INTERNATIONAL ENERGY AGENCY

# Energy Policies of IEA Countries

# CANADA

## 2004 Review

OECD

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**INTERNATIONAL ENERGY AGENCY**
9, rue de la Fédération,
75739 Paris Cedex 15, France

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

** IEA member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

**ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT**

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- to achieve the highest sustainable economic growth and employment and a rising standard of living in member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- to contribute to sound economic expansion in member as well as non-member countries in the process of economic development; and
- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

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# SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS



Endowed with large reserves of conventional and non-conventional oil and gas, coal, uranium and hydro, Canada is among the world largest producers of most types of energy and one of the IEA's largest energy exporters, principally to its neighbour, the United States. Marked differences among provinces and territories in terms of climate conditions and primary energy endowments, combined with a fast growing population and a strong and dynamic market economy, have impacts on energy demand and supply and raise a number of challenges for energy policy formulation and implementation.

Canada's constitution limits responsibilities of the federal government with regard to energy to international matters and inter-provincial issues and the management of uranium resources. The federal government is responsible for promoting the overall economic development of Canada. It is also responsible for preserving national interests such as environmental protection or the reduction of provincial economic disparities. Provinces have more jurisdictions over energy than the sub-national governments of other federal countries in the IEA. The only viable approach in addressing the most important energy policy challenges seems to be a process of intensive dialogue and consultation to achieve a national consensus on the goals and means of energy policies, but this process takes time. Such a process should cover areas such as climate change mitigation, streamlining regulatory regimes for new investment of energy production and transport, expansion of inter-provincial electricity interconnections, and research and development (R&D).

The federal government is to be commended for its efforts and achievements in formulating the National Climate Change Plan for Canada in November 2002. However, living up to Canada's commitment to the Kyoto Protocol, moving to a less emission-intensive economy and at the same time ensuring continued growth is the biggest single economic and political challenge for Canadian energy policy in the coming years. Curbing greenhouse gas (GHG) emissions is challenging because of the rapid expansion of energy production and exports. Since some provinces are clearly more emission-intensive than others, their support for the ratification of the Kyoto Protocol in December 2002 was not unanimous. Co-operation between the federal and provincial stakeholders is essential if Canada is to move forward with climate change policy implementation. While Canada has a large range of policies and measures to address climate change, the federal government's approach is largely based on fiscal and regulatory measures. Reflecting the concerns of the industrial sector competing with US industry not bound by the Kyoto

Protocol, the carbon price to Large Final Emitters under the covenant and trading scheme is capped. This could weaken the incentives for companies to invest in GHG emissions mitigation measures. Linking the emissions trading system with another region is being explored with a view to reducing carbon cost.

While Canada is highly energy-intensive owing to various structural factors, it has made significant improvements in increasing both the visibility of its energy efficiency policies and the systematic efforts to seek efficiency improvements in all sectors. Canada holds an excellent record in measuring, reporting and monitoring energy efficiency. Most importantly, measures are in place to constrain the growth of Canada's energy intensity. Nevertheless, Canada has at present the capacity to set more ambitious and sectoral energy efficiency goals and the ability to achieve them. Market-based measures, including fiscal incentives to increase more fuel-efficient vehicles could be explored in this direction. Close consultation between the federal and provincial governments is essential.

Although the old oil fields display a rather high decline rate, higher levels of exploration and production drilling of bitumen and synthetic crude oil from oil sands and east coast offshore have managed to keep production levels growing. To tap the potential of domestic resources further, exploration of areas under moratorium could be evaluated, taking relevant measures to maintain an adequate protection of the environment. There seems to be sufficient pipeline capacity to carry the current oil production to the refineries and the markets, but there may be concerns in the near future unless sufficient capacity is added. The production of unconventional oil from oil sands, which is growing rapidly, offers significant potential with a good economic margin. However, the huge forecast expansion in oil sands output will have local environmental impacts and contribute significantly to growth in Canada's greenhouse gas emissions because of the high energy input (from gas) to produce synthetic crude. Development of technologies to reduce emissions and the need for local natural resources such as gas and water is essential.

The Canadian gas sector is driven by competition upstream and is tightly integrated with the US market, with large volumes of Canadian gas exported to the US and Canadian gas prices determined in the larger North American market. The drilling level is high and the resulting increase in production, while disappointing, is sufficient to maintain supplies for domestic consumption and significant levels of exports over the long run, but not sufficient to allow for long-run export growth. Large and yet unexploited resources exist, but additional efforts are required in the future to stimulate production. Beyond possible external gas supply in the form of liquefied natural gas (LNG), possibilities to open the areas under moratorium should be considered. Resources of coal-bed methane (a form of non-conventional natural gas) have begun to be explored. The tax regime applied to coal-bed methane exploitation could be reviewed to facilitate its development.

Well-developed infrastructures within Canada and between Canada and the US create an integrated North American market for natural gas. Competition is well advanced. The regulatory environment in Canada has been stable, thereby creating trust by investors. However, within the regulated pipeline sector, different rates of return and risk between Canada and the US affect competition for investment between the two countries. In addition, setting up long pipelines requires numerous authorisations as these projects overlap jurisdictions. These factors could deter investors. Where jurisdictions overlap, the National Energy Board is working with provincial and territorial regulatory agencies to ensure that environmental assessment and regulatory issues are dealt with in a co-ordinated manner. Close co-operation with other regulatory agencies, wherever possible, and streamlining regulatory processes by using a single location for all administrative approvals should be pursued.

Although hydro remains the largest potential for renewable energy in Canada, large hydroelectricity projects (beyond 10 MW) are increasingly difficult to set up because of local environmental opposition. Given Canada's large potential, hydroelectricity should receive more attention. Recent years have witnessed a development of new and emerging renewable energy from wind or biomass. The main measures taken to support and guide the development of renewable energy in Canada are subsidies under various programmes. However, care should be taken to build in incentives for cost reduction in these subsidy programmes to ensure better cost-effectiveness than a flat subsidy scheme. Government efforts to maximise economic efficiency of the support scheme and to consider the advantage of market mechanisms are commendable. An *ad hoc* Federal-Provincial-Territorial Renewable Energy Working Group is now considering new measures to promote renewable energy, including the introduction of a renewable portfolio standard. It is also noteworthy that several provincial governments are also assessing the potential benefits of introducing portfolio standards.

Electricity in Canada is under provincial jurisdiction, except inter-provincial trade and international trade with the US. Nevertheless, with a view to improving overall competitiveness of the Canadian electricity industry and hence the Canadian economy, the federal government has to play an important role in several key policy issues. One of them is a growing interconnection between Canada and the US electricity markets. The grid failure of August 2003 demonstrates the need for more co-ordination and joint actions between the federal governments, provinces and their counterparts in the US with a view to ensuring reliability of electricity supply. Another issue is the development of Canadian domestic electricity markets through increased interprovincial transmission networks. When limited to provinces' boundaries, the supply-demand balance assessment cannot lead to cost-effective investment decisions. The federal authorities have to play their role to avoid this difficulty. While an east-west high-voltage link has yet to be proven economic, a larger integration of regional power systems is worth investigating. Further development of inter-provincial and international electricity trade could ensure effective competition. Close co-operation between the federal and provincial governments is the prerequisite.

The provinces have been taking the lead role in electricity market reform. They generally consider reform of the electricity sector to be necessary and are addressing the issues. However, reform progress differs among provinces according to their specific circumstances, such as the potential for competition, potential stranded assets and interconnections with other jurisdictions. Alberta and Ontario have competitive wholesale electricity markets and have introduced some amount of retail competition. Québec, Manitoba and British Columbia introduced wholesale competition while other provinces and territories continue to be supplied by one utility.

Electricity market liberalisation has sometimes been accompanied by increased price volatility. Measures taken in Ontario and Alberta to cope with electricity price hikes provide useful insights, in particular in terms of price volatility, investment and government intervention. To reduce the impact of a price hike on consumers after the market opening in 2002, the Ontario government capped retail prices for about half of the market at a price well below the cost of power and the entry cost of new plant. This has resulted in higher government subsidies and reluctance of investors to move into the Ontario market. The Alberta government, on the other hand, established a price cap at a relatively high level to preserve the signal for new investments to cope with price volatility. Investment in new generating capacity, which had been keeping pace with growth in peak load, is continuing. Such experiences could be shared in the federal and provincial co-operation process, and a consensus on effective mechanisms to mitigate the price volatility for households could be explored. While depending on provincial decisions, the federal government could also play a role in improvement of demand-side response with a view to reducing the extreme price volatility.

Canada's nuclear power programme is at a critical point in its history. While newer plants are performing satisfactorily, some of the old plants are experiencing significant problems in refurbishment. For example, the refurbishment of Pickering A Unit 4 resulted in significant cost and schedule overruns. An official review has identified many problems related to project management. Canada should not forgo potentially attractive nuclear generation and the federal government should explore barriers to the attainment of maximum economic generation from the existing shut down plants and help overcome the obstacles, consistent with safety considerations. At the same time, noting that Canada has a wide range of energy sources at its disposal for the generation of electricity, it seems appropriate for the federal government to evaluate the costs and benefits of deploying new nuclear plants in the future, in particular with regard to the environment and the benefit of further diversification of power generation in Canada.

The federal and provincial governments are making commendable efforts to pursue energy R&D. Since 1999, the federal government R&D budget has been increasing, which is in line with the policy goals to make Canada a strong knowledge economy. The announcement by the federal government on multi-year R&D programmes to cope with GHG emissions is also a positive development. Under the complexity of the funding structure, the federal government is establishing a comprehensive priority-setting process involving key stakeholders. Appropriate transparency in the decision-making process has been sought, supported by information exchange on activities and results achieved. Such efforts should be further enhanced.

## RECOMMENDATIONS

*The government of Canada should:*

### General Energy Policy

- *Take a more active role in initiating co-operation between federal, provincial and territorial governments with a view to formulating national consensus on the goals and implementation of energy policies, where mutually beneficial,* e.g. *through the Council of Energy Ministers and bilateral and regional meetings of ministers and high officials. Where applicable, the utilisation of the fiscal and regulatory instruments within federal jurisdiction could be explored to this end.*

- *Continue to ensure that the fiscal and regulatory environment is sufficiently competitive on an international basis to bring forward the necessary investment in the energy sector.*

- *Review energy data-reporting mechanisms to enable timely and comprehensive supply of data to policy-makers, analysts and international organisations.*

### Energy and the Environment

- *Increase co-operation with provinces and territories to implement the National Climate Change Plan, and in particular to develop the range of market incentives based on climate change policies. Promote the integration of energy and greenhouse policy objectives across federal and provincial governments.*

- *Undertake emissions projections and analyses for existing climate change measures as a matter of priority to allow adequate time for the identification of necessary further policies and measures.*

- *Investigate the possibility of strengthening and broadening the price signal for GHG emissions to ensure that new energy investment decisions reflect environmental considerations.*

- *Investigate further the potential of low emissions technology, and in particular $CO_2$ capture and storage, and the possibility of providing appropriate economic signals to encourage their development.*

### Energy Efficiency

- *Continue to assess the potential for energy efficiency improvements in all Canadian energy producing and consuming sectors.*

- *Consider developing a new set of sectoral efficiency goals associated with the introduction of market-based incentives to increase the uptake of efficient practices and enable structural change across sectors.*

- *Investigate and implement stronger measures to accelerate the shift towards more efficient motor vehicles.*

- *Enhance the consultation process between the levels of the federal government and provinces and territories in order to develop a comprehensive strategy for energy efficiency.*

### Oil

- *Evaluate the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *offshore British Columbia).*

- *Continue to facilitate the increase of oil sands production through fostering research and development on processing technology and environmental issues such as water treatment and $CO_2$ emissions reduction.*

- *Actively pursue the process to reduce the inconsistencies in regulations between the Atlantic provinces for offshore activity.*

### Natural Gas

- *Consider reviewing the tax regime to ensure the level playing field between conventional and unconventional gas to facilitate the exploitation of coal-bed methane.*

- *Continue reviewing the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *British Columbia).*

- *Investigate whether it is possible to streamline the pipeline approval process so that all the stakeholders are taken into consideration in a more efficient way. Promote the concept of a one-stop shop for regulatory approvals.*

- *Explore, in co-operation with the provincial regulatory authorities, the possibility of offering household customers an option to automatically be hedged against price volatility.*

### Renewable Energy Sources

- *Investigate further advancement of hydroelectricity.*

- *Consider new market-oriented incentives to promote renewable energy.*

- *Continue to facilitate production and use of renewable energy and concentrate its development and deployment on niche markets and high-value applications (*e.g. *energy supply to remote areas).*

### Electricity and Nuclear

#### Electricity

- *Work together with the provinces to ensure reliability of electricity supply, addressing the implications of increased physical and trade links with the US and the effects of ongoing market reform on grid design, operation and information flow between North American system operators and between other market participants.*

- *Analyse, in collaboration with the provinces, the costs/benefits of increased electricity links between different Canadian provinces with regard to improving reliability of electricity supply and creating larger electricity markets. Analyse what instruments would best promote such benefits.*

- *Set up a process of consultation with the provincial administrations and regulators, and the electricity supply industry to promote a consensus on the further advancement of electricity market reform compatible with US and Canadian electricity market developments. Co-ordinate with other policy objectives, such as environmental and industrial objectives, in order to ensure timely investment in new generating capacity.*

- *Foster the simplification of regulatory processes required for the authorisation of new power capacity and power lines.*

- *Address ways to improve demand-side response by all market participants. Analyse the effects of market opening on household consumers and find ways to protect households from electricity price volatility for those who do not wish to participate in the market.*

## Nuclear

- *Explore barriers for the attainment of maximum economic generation from existing nuclear plants, including the return of plants currently shut down, consistent with safety considerations. To this end, consider promoting more competition in the Canada Deuterium Uranium reactor (CANDU) plant operation and refurbishment.*
- *Evaluate the costs and benefits of adding new nuclear capacity with particular regard to the environment and diversification of power generation.*
- *Maintain under critical review the potential for the deployment of the Advanced CANDU Reactor (ACR).*
- *Maintain the option to deploy nuclear power plants in the future, irrespective of the success of the Atomic Energy of Canada Ltd. (AECL) in marketing ACR.*
- *Continue plans and intentions to identify and pursue the optimum means for the long-term management of irradiated CANDU fuel in Canada.*
- *Increase third-party liability of nuclear operators to reflect the kind of liabilities already established in other developed Western countries.*

## Energy Research and Development

- *If possible, avoid the kind of budget cuts in energy R&D that occurred in the late 1990s and maintain recent upward nominal trend.*
- *Increase further the profile of government R&D support by stronger prioritisation and concentration on a comprehensive view on key technologies.*

# *RÉSUMÉ DES CONCLUSIONS ET RECOMMANDATIONS*

Doté d'abondantes réserves de pétrole et de gaz conventionnels et non conventionnels, de charbon, d'uranium et de ressources hydrauliques, le Canada est l'un des plus grands producteurs et exportateurs d'énergie de l'AIE. Les États-Unis sont son principal débouché. Les situations contrastées entre provinces et territoires du point de vue des conditions climatiques et de la dotation en ressources énergétiques, ainsi qu'une croissance démographique rapide et une économie de marché solide et dynamique, influencent l'offre et la demande d'énergie et posent un certain nombre de défis pour la formulation et la mise en œuvre de la politique énergétique.

S'agissant de l'énergie, la Constitution canadienne limite la compétence du gouvernement fédéral aux questions internationales et interprovinciales ainsi qu'à la gestion des ressources en uranium. Le gouvernement fédéral est également responsable de la promotion du développement économique du Canada et de la défense des intérêts nationaux, tels que la protection de l'environnement ou la réduction des disparités économiques entre provinces. Les provinces quant à elles disposent, en matière d'énergie, de compétences plus étendues que les administrations infranationales d'autres pays membres de l'AIE à structure fédérale. Afin de dégager un consensus national sur les objectifs et moyens des politiques énergétiques, il est nécessaire d'engager un dialogue et une consultation intenses, mais ce processus prend du temps. Cette concertation devrait couvrir des domaines tels que la lutte contre le changement climatique, la simplification des régimes réglementaires des nouveaux investissements de production énergétique et de transport d'énergie, l'extension des interconnexions électriques entre provinces et la recherche-développement (R-D).

Il convient de féliciter le gouvernement fédéral pour ses efforts et les résultats atteints lors de la formulation du Plan du Canada sur les **changements climatiques**, en novembre 2002. Cependant, le respect de l'engagement pris par le Canada dans le cadre du Protocole de Kyoto – l'évolution vers une économie moins polluante tout en maintenant la croissance – constitue de loin le plus grand défi économique et politique du Canada dans le secteur énergétique pour les prochaines années. La réduction des émissions de gaz à effet de serre (GES) est un enjeu complexe face à l'expansion rapide de la production et des exportations énergétiques. Comme certaines provinces produisent à l'évidence des volumes d'émissions plus importants que d'autres, elles ne se sont pas prononcées unanimement en faveur de la ratification du Protocole de Kyoto, en décembre 2002. Pour que le Canada puisse progresser dans la mise en œuvre de sa politique de lutte contre le changement climatique, la coopération entre les parties prenantes fédérales et provinciales est essentielle. Bien que le Canada dispose d'une panoplie étendue de politiques et de mesures pour faire face au changement climatique, l'approche retenue par le gouvernement fédéral repose en grande partie sur des dispositions budgétaires et réglementaires. Afin de tenir compte des préoccupations du secteur industriel qui se trouve en concurrence avec l'industrie américaine, qui n'est pas soumise aux obligations du Protocole de Kyoto, le prix du carbone supporté par les grands émetteurs finaux prenant part au système d'échanges de droits d'émission est plafonné. Ceci pourrait affaiblir la motivation des entreprises à investir dans des mesures de réduction des émissions de GES. La possibilité de lier le système d'échanges de droits d'émission avec celui d'une autre région est à l'étude en vue de réduire le coût du carbone.

Bien que le Canada soit un gros consommateur d'énergie en raison de divers facteurs structurels, il a réalisé des progrès considérables en faisant mieux connaître ses politiques d'**efficacité énergétique** et en redoublant d'efforts pour améliorer l'efficacité dans tous les secteurs. Le Canada détient d'excellents résultats en matière de mesures, d'évaluation et de suivi de l'efficacité énergétique. Il a par ailleurs mis en place des mesures destinées à éviter la croissance de son intensité énergétique. Toutefois, le Canada pourrait se fixer des objectifs d'efficacité énergétique plus ambitieux au niveau sectoriel, et les moyens de les atteindre. Des mesures faisant appel aux mécanismes du marché, notamment des incitations fiscales visant à accroître le nombre de véhicules économes en carburant, pourraient être envisagées en ce sens. A cet égard, une étroite consultation entre le gouvernement fédéral et les autorités provinciales est essentielle.

Bien que la production des champs pétroliers les plus anciens marque un ralentissement rapide, l'intensification des activités de forage pour l'exploration et la production de **bitume** et de **pétrole** brut de synthèse extraits des sables bitumineux, ainsi que de pétrole en mer au large de la côte est, a permis de poursuivre la croissance de la production. Pour exploiter davantage les ressources du pays, il conviendrait d'évaluer les possibilités d'exploration de zones faisant actuellement l'objet d'un moratoire, en prenant les mesures nécessaires pour maintenir une protection adéquate de l'environnement. La capacité du réseau d'oléoducs semble suffisante pour acheminer la production pétrolière actuelle vers les raffineries et les marchés. Mais sans un renforcement de cette capacité, la situation pourrait devenir préoccupante dans un avenir proche. La production de pétrole non conventionnel à partir des sables bitumineux est en pleine croissance et offre des possibilités substantielles avec une bonne rentabilité. Cependant, la très forte expansion prévue de l'exploitation des sables bitumineux aura un impact sur l'environnement local et contribuera sensiblement à l'augmentation des émissions de GES du Canada, en raison notamment de la consommation énergétique élevée – principalement du gaz – nécessaire à ce type de production. Il est essentiel pour le Canada de mettre au point des technologies permettant de réduire les émissions et les besoins en ressources naturelles locales telles que le gaz et l'eau.

La production de **gaz** naturel obéit aux règles de la concurrence et le marché du gaz canadien est étroitement intégré au marché américain. Le Canada exporte des volumes significatifs de gaz vers les États-Unis, dont le prix est déterminé sur le marché nord-américain. L'activité de forage est intensive, et se traduit par une augmentation de la production qui, bien que décevante, est suffisante pour répondre à la demande intérieure et assurer des exportations importantes à long terme. Toutefois, cette augmentation n'est pas assez forte pour soutenir une croissance durable des exportations. Les immenses ressources encore inexploitées nécessiteront des efforts importants à l'avenir pour stimuler la production. Indépendamment de la possibilité de recourir à des sources d'approvisionnement extérieures sous forme de gaz naturel liquéfié (GNL), il conviendrait de relancer la question de l'ouverture à l'exploitation de zones actuellement visées par un moratoire. L'exploration des ressources de méthane de gisement houiller (ressources appartenant à la catégorie des gaz non conventionnels) a commencé récemment. Il pourrait être utile de réexaminer le régime fiscal de l'exploitation de ce méthane en vue de favoriser son développement.

Grâce à des infrastructures bien développées à l'intérieur du Canada et entre le Canada et les États-Unis, il existe un marché gazier nord-américain intégré. La concurrence y est active. La stabilité du cadre réglementaire canadien a créé un climat de confiance pour les investisseurs. Cependant, dans le secteur réglementé du transport par gazoduc, les écarts de marges bénéficiaires et de risques entre le Canada et les États-Unis ont une incidence sur la concurrence pour les investissements entre les deux pays. En outre, la construction de longs gazoducs exige de nombreuses autorisations car elle fait intervenir une multitude de juridictions. Ces facteurs constituent des barrières à l'investissement. Lorsque les juridictions se chevauchent, l'Office national de l'énergie collabore avec les autorités de régulation provinciales et territoriales pour faciliter leur coordination dans la gestion des processus réglementaires et de l'évaluation environnementale. Il convient d'établir une étroite coopération, dans la mesure du possible, avec les autres autorités de régulation et de rationaliser les processus réglementaires, par exemple en utilisant un système de guichet unique.

Bien que l'hydraulique demeure la principale source potentielle d'**énergie renouvelable** au Canada, les projets hydroélectriques d'envergure (plus de 10 mégawatts) sont de plus en plus difficiles à mettre en œuvre en raison de l'opposition que leur impact sur l'environnement suscite au plan local. Étant donné son énorme potentiel hydraulique, le Canada devrait accorder davantage d'attention à cette source d'énergie. On assiste depuis quelques années au développement des énergies renouvelables – vent et biomasse, par exemple – soutenu financièrement principalement par des subventions à l'investissement accordées par divers programmes. Il convient de prévoir dans ces programmes des incitations à la réduction des coûts pour obtenir un meilleur rapport coût-efficacité que celui offert par des subventions pures. Le gouvernement mérite d'être félicité pour ses efforts en vue d'optimiser l'efficacité économique du système d'aide et pour avoir étudié les avantages qu'il y aurait à introduire des mécanismes de marché. Un groupe de travail fédéral-provincial-territorial sur les énergies renouvelables examine actuellement de nouvelles mesures visant à promouvoir les énergies renouvelables, notamment la mise en œuvre d'une obligation de production d'énergie renouvelable. Il convient également de noter que plusieurs gouvernements provinciaux évaluent eux aussi les avantages potentiels de telles mesures.

Au Canada, la politique s'appliquant au **secteur électrique** incombe aux provinces, sauf en ce qui concerne les échanges interprovinciaux et les échanges avec les États-Unis. Néanmoins, pour améliorer la compétitivité globale de l'industrie électrique canadienne et, par là même, celle de l'économie canadienne dans son ensemble, le gouvernement fédéral a un rôle important à jouer sur plusieurs fronts, notamment celui de l'interconnexion croissante entre les marchés de l'électricité canadien et américain. La panne de réseau d'août 2003 a démontré la nécessité d'une meilleure coordination et d'actions communes entre les deux administrations fédérales, les provinces du Canada et les états des États-Unis, afin d'accroître la fiabilité de l'approvisionnement en électricité. Un autre aspect à prendre en compte est le développement des marchés intérieurs canadiens de l'électricité, par l'extension des réseaux de transport interprovinciaux. Si elle se limite aux frontières des provinces, l'évaluation de l'équilibre entre l'offre et la demande ne permet pas de prendre des décisions avisées en matière d'investissement. Les autorités fédérales ont donc un rôle à jouer pour résoudre cette difficulté. Si le bien-fondé d'une liaison haute tension est-ouest reste à démontrer, une intégration plus poussée des réseaux régionaux mérite d'être étudiée. Le développement accru des échanges interprovinciaux et internationaux d'électricité pourrait assurer une concurrence efficace, sous réserve d'une étroite coopération entre le gouvernement fédéral et celui des provinces.

Les provinces ont joué un rôle de premier plan dans la réforme des marchés de l'électricité, qu'elles jugent en général nécessaire, et ont entrepris l'examen des différentes questions qui se posent. Cependant, les progrès de cette réforme varient selon les provinces en fonction de leurs spécificités : possibilités de concurrence, existence d'actifs susceptibles de générer des coûts échoués et interconnexions des réseaux. L'Alberta et l'Ontario possèdent des marchés concurrentiels d'électricité de gros et ont introduit une certaine concurrence sur le marché de détail. Le Québec, le Manitoba et la Colombie-Britannique ont introduit la concurrence sur le marché de gros, tandis que d'autres provinces et territoires demeurent approvisionnés par un seul producteur.

La libéralisation des marchés de l'électricité s'est parfois accompagnée d'une plus grande instabilité des prix. Les mesures prises par l'Ontario et l'Alberta pour maîtriser l'augmentation des tarifs d'électricité permettent de mieux comprendre les effets de cette instabilité et les interventions auxquelles elle peut donner lieu. Pour atténuer l'impact d'une hausse de tarifs sur les consommateurs après l'ouverture des marchés en 2002, le gouvernement de l'Ontario a plafonné les tarifs de détail, pour environ la moitié du marché, à un niveau nettement inférieur au coût de production et au coût d'entrée d'un nouveau fournisseur sur le marché, ce qui s'est traduit par une augmentation des subventions publiques et a découragé les investisseurs de s'aventurer sur le marché ontarien. Le gouvernement de l'Alberta, de son côté, a fixé un prix plafond relativement élevé afin de préserver les signaux nécessaires aux nouveaux investissements dans un contexte de prix volatils. Les nouveaux investissements en capacité de production, qui avaient suivi le rythme de croissance de la demande de pointe, se poursuivent. L'expérience de ces deux provinces pourrait être mise en commun dans le cadre du processus de coopération fédérale et provinciale, qui permettrait de rechercher un consensus sur les mécanismes efficaces à mettre en œuvre afin d'atténuer l'instabilité des tarifs pour les ménages. La question relève certes de décisions provinciales, mais le gouvernement fédéral pourrait également jouer un rôle dans l'amélioration des mesures agissant sur la demande avec l'objectif de réduire la très grande instabilité des prix.

Le programme **nucléaire** canadien est arrivé à un point critique de son histoire. Si les centrales récentes fonctionnent de façon satisfaisante, la rénovation de certaines centrales plus anciennes pose d'importants problèmes. Par exemple, la rénovation de la tranche 4 du réacteur Pickering A a été extrêmement coûteuse et plus longue que prévu. Une enquête officielle a révélé de nombreux problèmes liés à la gestion du projet. Le Canada ne devrait pas renoncer à l'intérêt que présente l'électricité nucléaire, et le gouvernement fédéral devrait examiner les obstacles à l'optimisation économique de l'exploitation des centrales actuellement hors service et agir pour les surmonter, tout en respectant les impératifs de sûreté. Par ailleurs, comme le Canada dispose d'une grande diversité de sources d'énergie pour la production d'électricité, le gouvernement fédéral devrait évaluer les coûts et avantages de la mise en service de nouvelles centrales nucléaires à l'avenir, notamment pour l'environnement et pour l'intérêt que présente une diversification accrue de la production d'électricité au Canada.

Les gouvernements fédéral et provinciaux consacrent des efforts louables à la **recherche et au développement** (R-D) dans le domaine de l'énergie. Depuis 1999, le budget de R-D du gouvernement fédéral est en augmentation, conformément à l'objectif que le Canada s'est fixé de développer une solide économie reposant sur l'innovation. L'annonce par le gouvernement fédéral de programmes de R-D pluriannuels destinés à maîtriser les émissions de GES constitue également une évolution dans le bon sens. Compte tenu de la complexité de la structure de financement, le gouvernement fédéral met actuellement en place un processus complet d'établissement des priorités auquel sont associées les principales parties prenantes. Il a privilégié la transparence du processus décisionnel, favorisée par l'échange d'informations sur les activités et les résultats obtenus. Ces efforts devraient être encore accrus.

## RECOMMANDATIONS

*Le gouvernement du Canada devrait :*

### Politique énergétique générale

- *Jouer un rôle plus actif dans l'établissement de la coopération entre les gouvernements fédéral, provinciaux et territoriaux, en vue de dégager un consensus national sur les objectifs et la mise en œuvre des politiques énergétiques lorsque cette coopération peut être avantageuse pour tous, par exemple dans le cadre du Conseil des Ministres de l'énergie et des réunions bilatérales et régionales des ministres et des hauts fonctionnaires. Le recours à des instruments fiscaux et réglementaires dans le domaine de compétence fédérale pourrait être envisagé à cette fin.*

- *Continuer à veiller à ce que l'environnement fiscal et réglementaire ne réduise pas la capacité du Canada à attirer les investissements nécessaires dans le secteur énergétique.*

- *Revoir les mécanismes de soumission de données statistiques sur l'énergie pour faire en sorte que les décideurs, les analystes et les organisations internationales puissent disposer de données à jour et complètes.*

### Énergie et environnement

- *Accroître la coopération entre les provinces et les territoires pour mettre en œuvre le Plan national sur les changements climatiques, en particulier pour élaborer les incitations économiques correspondantes. Promouvoir l'intégration des objectifs de la politique énergétique avec ceux de la lutte contre l'effet de serre dans les programmes des gouvernements fédéral et provinciaux.*

- *Établir en priorité des projections des émissions et procéder à des analyses des mesures actuelles de lutte contre le changement climatique, de façon à disposer du temps voulu pour définir les politiques et mesures supplémentaires qui s'avéreront nécessaires.*

- *Étudier la possibilité de renforcer et d'élargir le signal prix des émissions de GES pour que les décisions d'investissements dans le domaine énergétique prennent en compte les considérations environnementales.*

- *Approfondir l'étude des possibilités qu'offrent les technologies peu polluantes et en particulier la séquestration et le stockage du $CO_2$, et étudier la possibilité d'émettre des signaux économiques appropriés pour en encourager le développement.*

### Efficacité énergétique

- *Continuer à évaluer les possibilités d'amélioration de l'efficacité énergétique dans tous les secteurs producteurs et consommateurs d'énergie au Canada.*

- *Envisager de définir une nouvelle série d'objectifs sectoriels en matière d'efficacité énergétique liés à l'introduction d'incitations économiques afin d'encourager l'adoption de pratiques efficaces et de favoriser le changement structurel dans les secteurs concernés.*

- *Étudier et mettre en œuvre des mesures plus rigoureuses pour accélérer l'évolution du parc automobile vers une plus grande efficacité énergétique.*

- *Renforcer le processus de consultation entre les administrations fédérale, provinciales et territoriales afin de mettre au point une stratégie globale d'efficacité énergétique.*

### Pétrole

- *Évaluer la possibilité d'ouvrir à l'exploitation des zones qui sont actuellement fermées à l'exploration et à la production, en prenant les mesures voulues pour maintenir une protection adéquate de l'environnement (par exemple, exploitation au large des côtes de la Colombie-Britannique).*

- *Continuer à faciliter l'accroissement de la production à partir des sables bitumineux en encourageant la recherche et le développement dans les domaines des technologies de traitement et des problèmes environnementaux tels que le traitement des eaux et la réduction des émissions de $CO_2$.*

- *S'employer activement à réduire les incohérences réglementaires entre les provinces atlantiques en ce qui concerne les activités pétrolières offshore.*

### Gaz naturel

- *Envisager de revoir le régime fiscal afin d'éviter toute discrimination entre gaz conventionnel et gaz non conventionnel et de faciliter également l'exploitation du méthane de gisements houillers.*

- *Continuer à étudier la possibilité d'ouvrir des zones aujourd'hui fermées à l'exploration et à la production, en prenant les mesures voulues pour maintenir une protection adéquate de l'environnement (par exemple en Colombie-Britannique).*

- *Déterminer s'il est possible de rationaliser le processus d'approbation des gazoducs de manière à ce que toutes les parties prenantes puissent être prises en compte de façon plus efficace. Promouvoir le concept de « guichet unique » pour les approbations réglementaires.*

- *Étudier, en coopération avec les autorités réglementaires provinciales, la possibilité d'offrir aux particuliers le moyen de se protéger automatiquement contre la volatilité des prix.*

### *Energies renouvelables*

- *Étudier les moyens de développer davantage l'hydro-électricité.*

- *Envisager le recours à de nouveaux mécanismes d'incitation économique pour promouvoir les énergies renouvelables.*

- *Continuer à faciliter la production et l'utilisation des énergies renouvelables et concentrer leur développement et leur déploiement sur des niches de marché et des applications à forte valeur ajoutée (par exemple, approvisionnement énergétique des zones éloignées).*

### *Électricité et nucléaire*

#### *Électricité*

- *Travailler de concert avec les provinces pour assurer la fiabilité de la fourniture en électricité, en prenant en compte les implications d'un resserrement des liens physiques et commerciaux avec les États-Unis ainsi que celles de la réforme du marché en cours sur la conception du réseau, son exploitation et la circulation de l'information entre les opérateurs du réseau nord-américain, et entre ces derniers et les autres acteurs du marché.*

- *Analyser, en collaboration avec les provinces, les coûts et bénéfices du développement de nouvelles connexions entre différentes provinces canadiennes pour améliorer la fiabilité de la fourniture en électricité et créer des marchés plus vastes. Déterminer les instruments qui seraient les plus adaptés pour promouvoir ces avantages.*

- *Créer un processus de consultation avec les administrations et les instances régulatrices des provinces, ainsi qu'avec l'industrie électrique pour promouvoir un consensus sur la poursuite de la réforme des marchés de l'électricité qui soit compatible avec l'évolution des marchés américain et canadien. Assurer la coordination de ces réformes avec les autres objectifs des pouvoirs publics, notamment ceux des politiques environnementales et industrielles, afin que les investissements nécessaires soient faits en temps voulu pour créer de nouveaux moyens de production.*

- *Promouvoir la simplification des processus réglementaires d'obtention des autorisations concernant de nouvelles capacités de production et de nouvelles lignes.*

- *Étudier les moyens d'améliorer la réponse de toutes les catégories de consommateurs. Analyser les effets de l'ouverture des marchés sur les ménages et les moyens de protéger contre la volatilité des prix de l'électricité les ménages qui ne souhaitent pas participer aux nouveaux marchés ainsi créés.*

### Nucléaire

- *Examiner les obstacles à l'optimisation économique de la production des centrales nucléaires existantes, y compris la remise en service de centrales actuellement fermées, dans le respect des normes de sûreté. À cette fin, envisager de promouvoir une plus forte concurrence pour l'exploitation et la rénovation des réacteurs canadiens à deutérium-uranium (CANDU).*

- *Évaluer les coûts et bénéfices de l'accroissement de la capacité nucléaire, particulièrement du point de vue de l'environnement et de la diversification du parc de centrales.*

- *Suivre de près les possibilités de déploiement du réacteur CANDU avancé (ACR).*

- *Conserver l'option de mettre en service des centrales nucléaires à l'avenir, indépendamment des résultats qu'Énergie atomique du Canada limitée (EACL) obtiendra dans ses efforts de commercialisation de l'ACR.*

- *Poursuivre les plans et préciser les intentions en vue de définir et de mettre en œuvre les meilleurs moyens de gérer à long terme le combustible épuisé des réacteurs CANDU au Canada.*

- *Renforcer la responsabilité civile des exploitants de centrales nucléaires, dans le sens de ce qu'ont déjà fait d'autres pays occidentaux industrialisés.*

## Recherche et développement

- *Si possible, éviter d'imposer des compressions budgétaires à la R-D dans le domaine de l'énergie, comme celles qui ont affecté le secteur à la fin des années 1990, et maintenir la récente tendance en faveur d'une hausse nominale.*

- *Faire mieux connaître l'aide publique à la R-D en établissant des priorités plus rigoureuses et en concentrant cette aide sur une vision globale des technologies clés.*

# ORGANISATION OF THE REVIEW



An IEA review team visited Canada in November 2003 to review the country's energy policies. This report has been drafted on the basis of information received during and prior to the visit, including the official Canadian government's response to the IEA 2002-03 policy questionnaire, and the views expressed by various parties during the visit. Pierre Audinet managed the review process and drafted this report, apart from the section on nuclear which was drafted by Peter Wilmer and the paragraph on oil emergency preparedness which was drafted by Rioji Iwama (IEA). Jane Anderson provided support for the chapter on the environment, Ralf Dickel for the chapters on electricity and gas, and Sabine Semke for the chapter on R&D. The team greatly appreciated the openness and co-operation shown by everyone it met, in Ottawa, Calgary (Alberta), Fort McMurray (Alberta) and Toronto (Ontario).

The members of the team were:

**Mr. Bjarne Moe**
(Team Leader)
Director-General
Ministry of Petroleum and Energy
Norway

**Ms. Jane Anderson**
Policy Adviser
Department of Industry,
Tourism and Resources
Australia

**Mr. Richard Lavergne**
Head, Energy Survey Unit
Ministry of Economy,
Finance and Industry
France

**Ms. Sabine Semke**
Head, PTJ-GIN Division
Forschungszentrum Juelich
Germany

**Mr. Ralf Dickel**
Head, Energy Diversification Division
International Energy Agency

**Mr. Noé van Hulst**
Director, Long Term Co-operation
and Policy Analysis Office
International Energy Agency

**Mr. Peter Wilmer**
Head, Nuclear Development Division
Nuclear Energy Agency

**Mr. Pierre Audinet**
(Canada Desk Officer)
Administrator,
Country Studies Division
International Energy Agency

# ORGANISATIONS VISITED

The team held discussions with the following organisations:

- Alberta Energy and Utilities Board
- Alberta Ministry of Energy
- Athabasca Regional Issues Working group
- Athabasca Tribal Council
- Bruce Power
- Canadian Association of Petroleum Producers
- Canadian Electricity Association
- Canadian Energy Efficiency Alliance
- Canadian Energy Pipeline Association
- Canadian Energy Research Institute
- Canadian Gas Association
- Canadian Hydropower Association
- Canadian Nuclear Association
- Canadian Society for Unconventional Gas
- Coal Association of Canada
- Department of Foreign Affairs and International Trade
- Enbridge
- Fuel Cells Canada
- IFP Technologies (Canada) Inc.
- National Energy Board
- Natural Resources Canada
- Ontario Ministry of Energy
- Ontario Power Generation
- Ontario Independent Electricity Market Operator
- Stuart Energy

- Sustainable Buildings Canada
- Suncor
- Syncrude
- Terasen Pipelines
- TransCanada

## REVIEW CRITERIA

The *Shared Goals* of the IEA, which were adopted by IEA Ministers at their 4 June 1993 meeting, held in Paris, provide the evaluation criteria for in-depth reviews conducted by the Agency. The *Shared Goals* are set out in Annex B. More generally, reviews assess the effectiveness of the country's energy policies in achieving a balance between economic efficiency, environmental sustainability and energy security.

Figure 1
## Map of Canada

# GENERAL ENERGY SCENE AND ENERGY POLICY

## BACKGROUND

Canada is a federation of ten provinces and three territories[1] and is a constitutional monarchy. The Parliament of Canada, in the capital Ottawa, consists of the elected House of Commons and the appointed Senate.

Canada is the largest of the OECD countries (nearly 10 million square kilometres) and the second-largest country by area in the world with a population of about 31 million. The population grew by 11% between 1990 and 2000, almost twice the IEA average, and is projected to increase to about 35 million by the year 2020. Nearly one-third of the population lives in the three largest cities of Toronto, Montréal and Vancouver. Measured in terms of GDP per capita, Canada has the sixth-highest standard of living in the world.

Gross domestic product grew by 1.5% between 2000 and 2001, but recovered to 3.3% in 2002. The Canadian economy has grown strongly by 32% between 1990 and 2000, against 27% for all IEA countries. Exports account for over one-third of gross domestic product and private consumption is growing at about 5% per year. Economic growth by region varies substantially. In the period 1997 to 2002, the Canadian average annual growth rate reached 3.8%, varying from 0.5% in Yukon, to 6.7% in Newfoundland & Labrador. Large provinces experienced sustained growth during the same period (*e.g.* 4.3% per annum in Ontario, 3.6% in Québec, or 3.5% in Alberta). Energy investments were important for growth in Alberta and the Atlantic region, particularly Newfoundland and Nova Scotia.

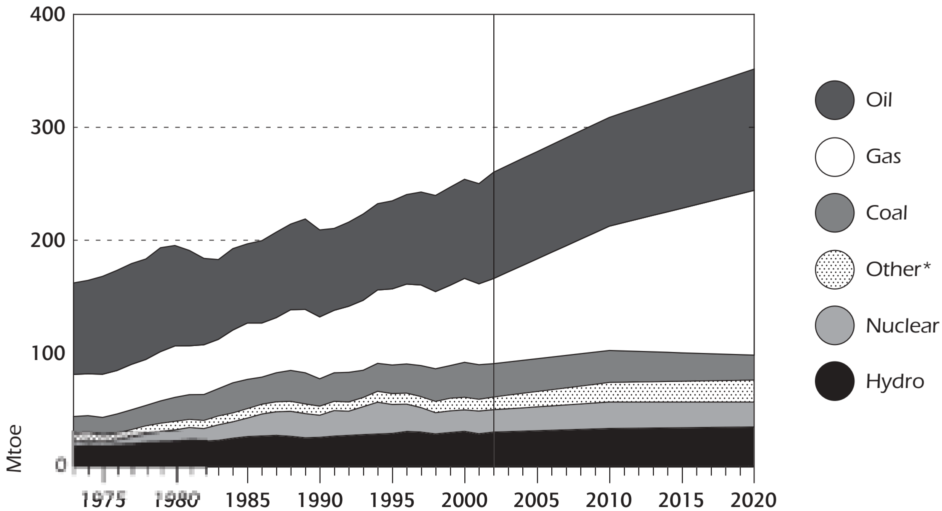
## ENERGY SUPPLY AND DEMAND

In 2002, the total primary energy supply (TPES) was 259 Mtoe, representing a growth of 20% over the 1990 level. There has been no substantial change in the share of each energy source during that decade. In 2002, oil represented 36%, gas 29%, coal 11%, hydro 12%, nuclear 8% and combustible renewables and wastes other than hydro, 4%. About three-quarters of Canada's TPES are derived from fossil fuels.

1. Alberta, British Columbia, Prince Edward Island, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, Saskatchewan, Newfoundland and Labrador, Northwest Territories, Yukon Territory and Nunavut. Nunavut was created on 1 April 1999.

Figure 2

**Total Primary Energy Supply, 1973 to 2020**




* includes geothermal, solar, wind and combustible renewables.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

Canada's total energy production is large by international standards (see chapters on oil, gas, coal, electricity and renewables for details). It grew substantially from 274 Mtoe in 1990 to 392 Mtoe in 2002. Canada is endowed with vast energy resources, many of which can be exploited at relatively low cost. The country has huge reserves of oil (conventional and oil sands), gas (conventional as well as coal-bed methane), coal and uranium. In 2002, Canada had the second-largest installed hydroelectricity capacity (67 GW, after the US), and large remaining potential to be tapped.

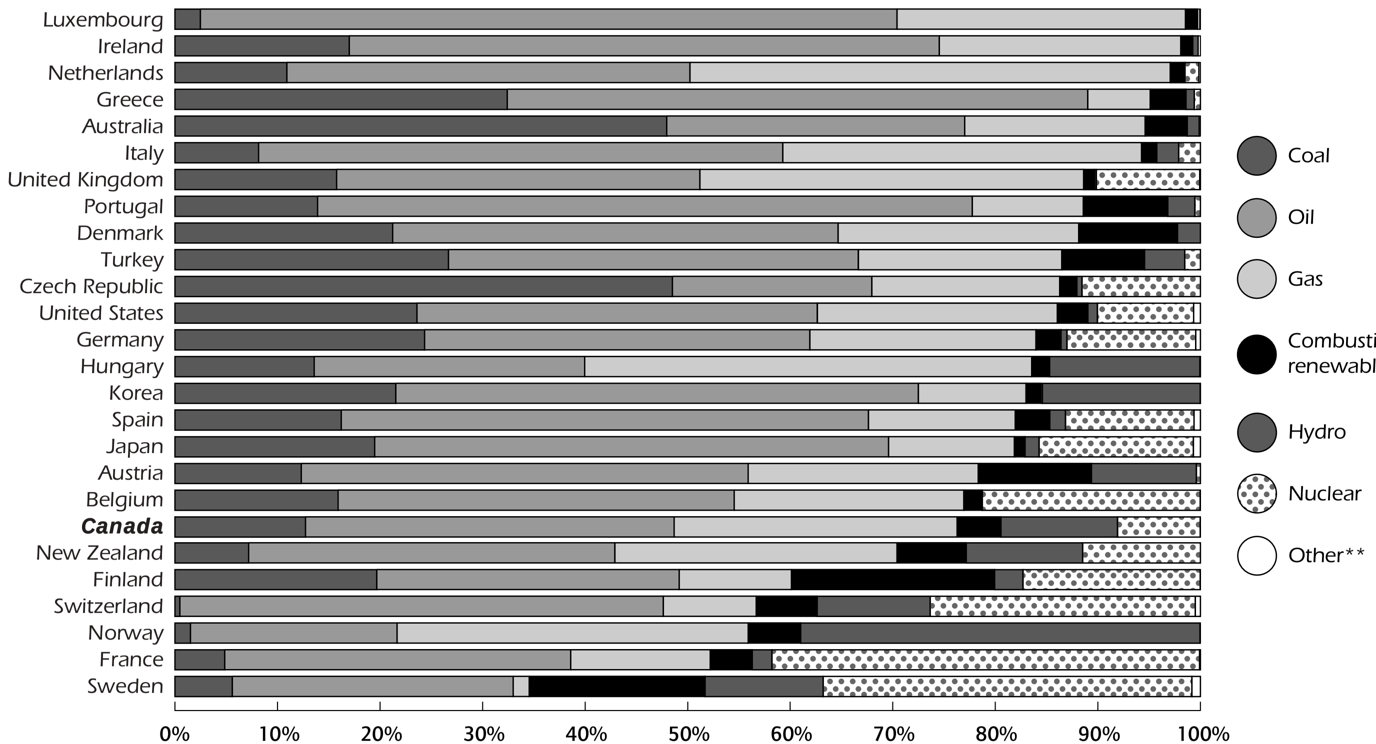
Energy consumption in Canada is driven by sustained economic and population growth, and the fact that Canada remains an energy-intensive economy as a primary producer and exporter of vast quantities of primary and secondary energy (see Chapter 5 for detailed information on Canada's final energy consumption).

Canada's net energy exports more than doubled from 61 Mtoe in 1990 to 138 Mtoe in 2002. About 30% and 61% of net energy exports are oil and gas respectively. In 2001, energy generated $26 billion of exports[2]. In total, energy accounted for 6.2% of GDP in 2002.

2. The $ sign refers to Canadian dollars throughout the text. $ 1 = US$ 0.714 (2003), US$ 0.639 (2002); US$ 0.646 (2001) (and €1 = US$ 1.126 in 2003).

Figure 3

## Total Primary Energy Supply in IEA Countries, 2002*




* preliminary data.
** includes geothermal, solar, wind and ambient heat production.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003.

Table 1

## Canada's Oil and Gas Remaining Reserves

(estimated on 31 December 2001, in cubic metres)

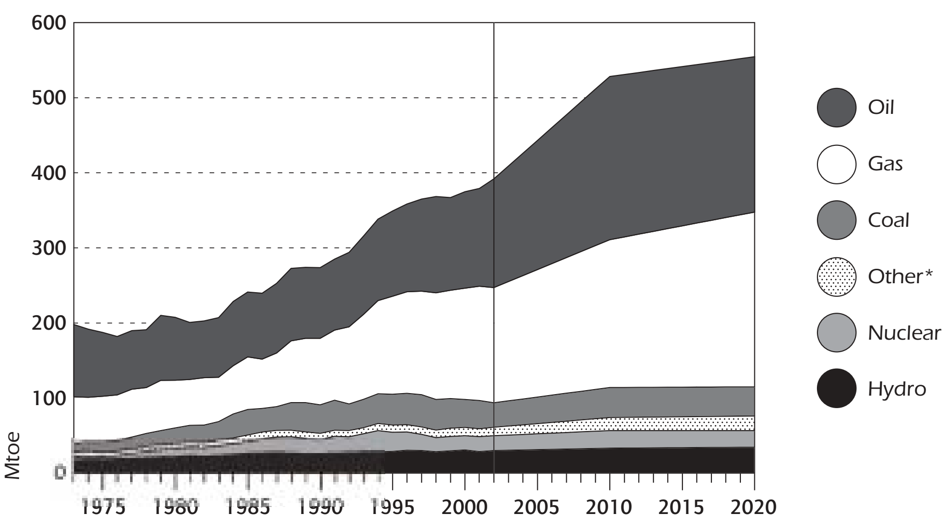
| | *Conventional crude oil (millions)* | *Crude bitumen (millions)* | *Natural gas (billions)* |
|---|---|---|---|
| British Columbia | 25.5 | - | 252.1 |
| Alberta | 278.4 | 27 770.0 | 1 182.7 |
| Saskatchewan | 182.0 | - | 77.6 |
| Manitoba | 3.8 | - | - |
| Ontario | 1.9 | - | 11.6 |
| Northwest Territories and Yukon | 10.4 | - | 14.0 |
| Nova Scotia | 0.0 | - | 76.5 |
| Newfoundland | 178.3 | - | - |
| **Total** | **680.3** | **27 770.0** | **1 614.5** |

Note: Large amounts of methane-rich gas are stored in coal beds. The US Geological Survey (1995) estimates resources worldwide of such "non-conventional gas" to 210 trillion cubic metres, out of which Canadian Gas Association puts Canada's resources of coal-bed methane to 15 trillion cubic metres. Coal-bed methane numbers refer to potential resources, not reserves, as there are many uncertainties related to their exploitation.

Source: National Energy Board, Annual report 2002.

Figure 4

## Energy Production by Source, 1973 to 2020




* includes geothermal, solar, wind and combustible renewables.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

Canada is a major supplier of energy to the United States and Japan. In 2001, Canadian gas exports to the US represented 93% of US natural gas imports, and its coking coal exports to Japan amounted to 45% of Japanese coking coal imports. Exports of crude oil were valued at $16.1 billion in 2001, 99% of it being for the US market.

Although Canada is a net exporter of energy, it imports significant quantities of coal (13.5 Mtoe in 2002), and oil (54 Mtoe). Coal enters via Ontario. Oil enters the country mostly from the east coast to supply the consumption centres located far from domestic resources (as these are mainly in the west).

The outlook to 2020 shows a sustained growth of supply to 350 Mtoe and production to 555 Mtoe due in particular to the likely development of further energy production projects for exports (such as oil sands) and a revised electricity fuel mix. Oil sands production is itself using large quantities of energy. Projections developed by the National Energy Board (NEB) assume an average annual rate of growth in the economy between 2.2% and 2.7% between 2000 and 2025. The NEB forecasts of energy production projects include assumptions on:

- Increased offshore oil production in Newfoundland and Labrador at the Hibernia, Terra Nova and White Rose fields.
- Increased natural gas production in Nova Scotia.
- Increased oil sands mining and *in situ* developments (an additional 625 thousand barrels per day by 2010 in Alberta).
- Increased natural gas production from offshore British Columbia.
- Possibility of Mackenzie natural gas development by 2015.
- Changes in primary energy supply for electricity production, particularly increased gas consumption and reduced coal consumption.

## *ENERGY SITUATION IN THE PROVINCES AND TERRITORIES*

Several driving forces shape energy policy at provincial levels:

- Provinces and territories have significantly different primary resource endowments from each other.
- Provinces and territories are owners of their ground resources (apart from resources located in aboriginal lands and national parks) and have primary responsibilities in shaping policies implemented in their jurisdictions.
- Energy plays a large role in some of the provinces' creation of wealth (*e.g.* Alberta, Québec or Saskatchewan, Newfoundland and Labrador).

For most provinces, the share of external energy trade they carry out with bordering US states is often larger than with Canadian neighbouring provinces.

### Table 2

## Canadian Provinces' and Territories' Economy and Geography, 2002

| | *Area, km²* | *Population, thousand* | *GDP, million $* | *GDP per capita, $* |
|---|---|---|---|---|
| **Canada** | **9 984 670** | **31 414** | **1 141 756** | **36 357** |
| Newfoundland and Labrador | 405 212 | 532 | 15 982 | 30 041 |
| Prince Edward Island | 5 660 | 140 | 3 767 | 26 907 |
| Nova Scotia | 55 284 | 945 | 26 193 | 27 717 |
| New Brunswick | 72 908 | 757 | 20 888 | 27 593 |
| Québec | 1 542 056 | 7 455 | 242 914 | 32 584 |
| Ontario | 1 076 395 | 12 068 | 470 567 | 38 993 |
| Manitoba | 647 797 | 1 151 | 36 527 | 31 735 |
| Saskatchewan | 651 036 | 1 012 | 34 526 | 34 117 |
| Alberta | 661 848 | 3 114 | 150 469 | 48 320 |
| British Columbia | 944 735 | 4 141 | 134 365 | 32 447 |
| Yukon | 482 443 | 30 | 1 211 | 40 367 |
| Northwest Territories | 1 346 106 | 41 | 3 412 | 83 220 |
| Nunavut | 2 093 190 | 29 | 935 | 32 241 |

Source: Statistics Canada.

### Table 3

## Canadian Provinces' and Territories' Energy Production, 2001

(PJ)

| | *Total primary energy* | *Coal* | *Oil* | *Natural gas* | *Hydro* | *Nuclear* |
|---|---|---|---|---|---|---|
| Newfoundland and Labrador | 470.0 | - | 320.9 | 9.4 | 139.8 | - |
| Prince Edward Island | - | - | - | - | - | - |
| Nova Scotia | 252.4 | 25.5 | 20.1 | 196.9 | 2.7 | - |
| New Brunswick | 28.0 | 4.4 | - | - | 7.4 | 16.5 |
| Québec | 609.2 | - | - | - | 592.3 | 17.3 |
| Ontario | 383.8 | - | 9.4 | 13.5 | 133.7 | 232.1 |
| Manitoba | 143.4 | - | 25.0 | - | 118.4 | - |
| Saskatchewan | 1 463.9 | 170.9 | 968.8 | 314.0 | 8.6 | - |
| Alberta | 10 335.5 | 629.4 | 3 495.7 | 5 598.3 | 5.6 | - |
| British Columbia | 2 035.0 | 702.7 | 125.3 | 1 008.5 | 177.0 | - |
| Yukon, NWT, Nunavut | 122.7 | - | 59.2 | 61.5 | 2.0 | - |
| **Canada** | **15 844.1** | **1 533.0** | **5 024.3** | **7 202.1** | **1 187.6** | **265.8** |

Source: Statistics Canada.

# ENERGY ADMINISTRATION

The Canadian constitution provides that legislative authority over energy matters is divided between the provinces and the federal government both geographically and functionally (see Table 4).

**Table 4**

**Constitutional Division of Responsibilities for Energy**

| *Provincial governments* | *Federal government* |
|---|---|
| • Development and management of resources within provincial boundaries.<br>• Property and civil rights within the province, *i.e.* environment, health, safety, land use, consumer protection, etc.<br>• Regulation and legislative framework for electricity and natural gas, including in many cases ownership of Crown corporations engaged in these activities.<br>• Secure appropriate economic rent as resource owner from Crown mineral rights.<br>• Policies in the provincial interests, such as economic development, and energy science and technology.<br>• Intra-provincial trade. | • Resource management outside the provinces.<br>• Uranium/nuclear power.<br>• Inter-provincial/international trade and commerce.<br>• Inter-provincial and international works and undertakings.<br>• Transboundary environmental impacts.<br>• Policies and legislation in the national interest:<br>– Economic development.<br>– Energy security.<br>– Federal energy R&D. |

On the east coast offshore areas adjacent to the provinces of Newfoundland and Labrador and Nova Scotia, known as the Accord Areas, Canada and the relevant provinces have reached an agreement on joint management of the offshore oil and gas resources and revenue sharing. These agreements were implemented through the adoption of legislation. The legislation clearly states that nothing in the agreements is to be construed as a basis for a claim by any province in respect of interest in or legislative authority over the resources. The oil and natural gas industry is jointly managed by the federal and provincial governments through the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canada-Newfoundland Offshore Petroleum Board (CNOPB).

Electricity is almost exclusively regulated at the provincial level. Each province has a separate regulator. Provincial regulators in some cases operate at arms-length from the government but are in other cases part of the policy arms of their respective government.

Indian and Northern Affairs Canada acts for the territories on all energy matters in the Northwest Territories and Nunavut. Under the process of devolution, the Yukon Territory now has similar jurisdiction to all other provinces in the federation. Negotiations are currently under way to devolve responsibility for energy matters to the Northwest Territories.

Policy co-ordination between the federal and the provincial levels takes place through formal high-level committees and informal contacts and consultations. At the highest level, the Council of Energy Ministers gathers annually all provincial, territorial and federal energy ministers. To address topical issues, *ad hoc* consultations take place. For example, to define climate change mitigation policies, federal, provincial, territorial and municipal governments in Canada have been working jointly with interested parties to develop the National Climate Change Plan for Canada (see chapter on Energy and the Environment). Between 1998 and 2001, some 450 experts from a broad cross-section of government, business and industry, academia, environmental groups and non-governmental organisations participated in 16 Issue Tables/Groups that examined and analysed the impacts, costs and benefits of options to address climate change. The outcome was presented to the Council of Ministers for consideration in 2000-1. Another example is the Federal-Provincial-Territorial Electricity Working Group created by federal, provincial and territorial energy ministers in 2003 to address inter-provincial issues on electricity and jointly develop solutions to common problems such as accelerating the process for issuing environmental and other permits for electricity production.

Natural Resources Canada (NRCan) is the primary federal government department responsible for energy. NRCan has the lead in general energy policy. It works with other government departments in the realm of energy efficiency, energy and the environment, renewables, energy in transportation, R&D and the general balance between energy policy goals and other objectives relating to Canada's economic development. NRCan also works towards developing and implementing policies facilitating oil, gas and nuclear energy development.

The collection of energy statistics in Canada involves many players, partly owing to the devolution of powers to provinces. At the federal level, main responsibility for collecting and processing all data, including energy data, belongs to Statistics Canada (StatsCan). StatsCan sends final data to NRCan for forwarding to the IEA. The provinces collect data from the industry for their regional needs. The National Energy Board collects and publishes energy export statistics.

There are two agencies responsible for energy regulation on behalf of the federal government: the National Energy Board and the Canadian Nuclear Safety Commission. They both report to Parliament through the Minister of

Natural Resources, but are independent regulatory institutions. The CNSOPB and CNOPB mentioned earlier also have energy regulation duties in their regions for the oil and gas sectors.

### NATIONAL ENERGY BOARD (NEB)

NEB regulates inter-provincial and international oil and gas pipelines, as well as the construction and operation of international power lines and designated inter-provincial lines under federal jurisdiction. NEB is also engaged in environmental protection, ensuring that environmental issues are managed during the planning, construction, operation and abandonment of energy projects within its jurisdiction. There are agreements between the NEB and the territorial boards with respect to regulations and assessments surrounding the development of the Mackenzie Valley Pipeline.

NEB also monitors the Canadian energy market on an ongoing basis and publishes reports on the energy market, including a periodic outlook for Canada's energy future, reports on the supply side of the industry, and energy market developments.

### CANADIAN NUCLEAR SAFETY COMMISSION (CNSC)

The CNSC regulates all aspects of the nuclear fuel cycle, including uranium mining, fuel production, nuclear power plants, nuclear research facilities and uses of nuclear material.

## ENERGY POLICY

The government of Canada's energy policy continues to aim at achieving a balance between:

- The environmentally responsible production and use of energy (including dimensions of health and safety).
- Growth and competitiveness of the Canadian economy.
- Secure and competitively priced energy and the protection of infrastructure.

The core of energy policy remains the same as in the IEA 2000 review, with actions to increase environmental protection, encourage competitive energy markets, develop nuclear power and uranium production and facilitate oil and gas production in frontier lands.

Energy supply and demand conditions are also guided by the North American Free Trade Agreement (NAFTA), which provides open access to US markets for Canadian energy.

On 16 December 2002, Canada ratified the Kyoto Protocol, under the United Nations Framework Convention on Climate Change (UNFCCC) after several years of discussions with provincial and territorial governments and other stakeholders. The ratification decision was debated in the House of Commons and the Senate.

## ENERGY SECURITY

Canada is a net exporter of oil, natural gas and electricity, and the federal government does not consider energy supply security as an issue of immediate significance. Primary energy reserves are currently largely sufficient to cover domestic needs (see oil, gas and electricity chapters). Energy imports are limited and Canada's energy policy is to allow normal market forces to reallocate supplies according to prices. Under NAFTA, neither Canadian nor US governments can arbitrarily cut off energy exports to the other.

In the event of disruptions to energy supply, the provinces have authority to implement demand restraint measures. Under certain circumstances (*i.e.* after declaring an emergency – a global oil supply reduction of 7%), a provision exists for measures to be taken by the federal government under the authority of the Energy Supplies Emergency Act, which empowers the Energy Supplies Allocation Board to reallocate energy supplies within Canada. Similarly, the Emergencies Act is another legislation that provides for special and temporary measures to ensure safety and security when a national emergency is declared. The federal government can order requisitions of energy supplies or their disposal, but this kind of process is time-consuming.

### OIL

Canada is a net oil exporter. Refineries in western Canada run domestically-produced crude oil, those in Québec and the eastern provinces run imported crude oil, while refineries in Ontario run both. Crude oil imports from OECD countries account for approximately 60%, while almost 90% of oil products imports are from OECD countries (mainly from the US). These imports may be replaced by domestic sources in times of supply shortages. The Emergency Supplies Allocation Board is mandated to prepare, develop and maintain in a state of readiness programmes to allocate crude oil and petroleum products, restrain demand for petroleum products, and ration gasoline and diesel fuel in case of emergency (see Chapter 6).

### NATURAL GAS

Canada is currently a net gas exporter. Natural gas production is concentrated in the western provinces, with some production off the east coast. In central

Canada, natural gas imports from western Canada are supplemented by very small amounts of imports from the US. In the future, Canada's ability to export may be significantly reduced with growing domestic consumption of natural gas needed to extract oil sands and a tapering of domestic natural gas production growth.

Gas markets are largely liberalised or deregulated. Local gas distribution companies (LDCs) ensure that their main consumers have enough gas by contracting sufficient pipeline capacity and storage to cover peak winter demand. LDCs are regulated, and must prudently serve their markets. This usually involves ensuring sufficient pipeline and storage capacity. Although there is no specific regulation to guarantee physical security of supply, it is ensured by multiple loops in the Canadian pipeline system.

## ELECTRICITY

Canada trades significant quantities of electricity with the US at many points stretching from Maine to Washington (see Chapter 10). Québec, in particular, is a major exporter to the northeast US. The North American Electric Reliability Council (NERC) is developing a single set of reliability standards to replace its existing operating policies and planning standards applying to the whole of North America (US, Canada and Mexico). NERC has projected Canada to have adequate electricity supplies until 2011, provided new generation is added as planned.

The provinces have Public Utility Boards that monitor and regulate the distribution of natural gas and electricity. In the two provinces with competitive wholesale electricity markets (Alberta and Ontario), their respective regulatory authorities have designated a backstop entity that is responsible for adding new infrastructure if the market does not respond to needed increases in infrastructure, in accordance with NERC recommendations.

On 14 August 2003, a cascading power outage, originating in the US, resulted in a blackout affecting more than 50 million individuals in Ontario and the northern US. It took ten days before the entire system was back to normal. NRCan had an emergency operations centre up and running in one hour. The Canadian Prime Minister and the US President established a Joint Canada-US Task Force on the Power Outage within 24 hours. The task force completed a report on the causes of the blackout in November 2003 and followed up with a second report in April 2004 that has provided policy recommendations. Recommendations call for a strong commitment by the electricity supply industry, its related organisations as well as the governments and regulators to adhere to strict reliability standards to operate the bulk power systems, including the application of penalties for non-compliance. Recommendations also called for internalising the costs of increased reliability.

All uranium production occurs in remote locations of northern Saskatchewan. Canadian uranium requirements are modest compared to the current rate of production. More than 85% of uranium production is exported and about 50% of the material exported goes to the United States. Only exports consistent with Canada's Nuclear Non Proliferation Policy are authorised.

## PHYSICAL SECURITY

The Office of Critical Infrastructure Protection and Emergency Preparedness (OCIPEP), initially under the Ministry of Defence and integrated under the Ministry of Public Safety and Emergency Preparedness since 2003, is mandated to provide national leadership to protect Canada's critical infrastructure, including electricity generation and transmission infrastructure, from physical and cyber threats. In 2001, NRCan created the Energy Infrastructure Protection Division as a nodal point within the energy administration, with a mandate to enhance the security of energy infrastructure in response to the government of Canada identifying energy as one of four key infrastructure sectors (banking, transportation and telecommunications being the others).

# ENERGY PRICES AND TAXES

Energy prices in Canada are generally lower than the IEA average, mainly because of the availability of primary energy resources and lower taxation rates. Oil and field gas prices have been deregulated since the mid-1980s.

**Table 5**

**Energy End-use Prices, First Quarter 2003**

(US$/toe)

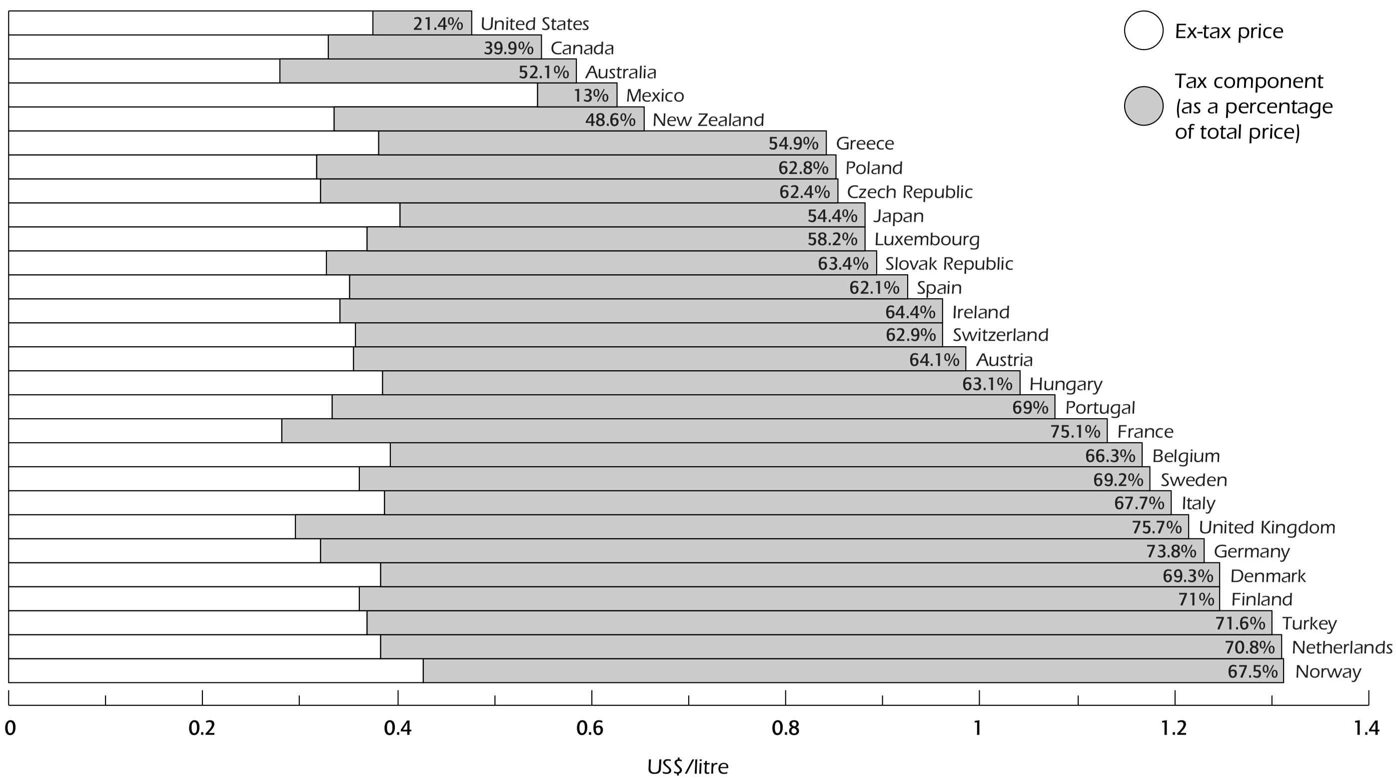
| *Fuel* | *Canada* | *Tax (%)* | *OECD* | *Ratio to OECD (%)* |
|---|---|---|---|---|
| High sulphur fuel oil for industry | 211.3* | - | 251.3* | 84 |
| Light fuel oil for industry | 345.6 | - | 373.7 | 92 |
| Light fuel oil for households | 526.9 | 10.2 | 547.7 | 96 |
| Automotive diesel for commercial use | 570.4 | 29.8 | 721.4 | 79 |
| Premium unleaded gasoline (98 RON) | 708.7 | 35.7 | 1 481.4*** | 48 |
| Natural gas for industry | 120.9** | - | 205.7** | 59 |
| Natural gas for households | 326.7** | - | 425.9** | 77 |

* 4Q2002; **2001; ***OECD Europe.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, Second Quarter 2003.

**Figure 5**

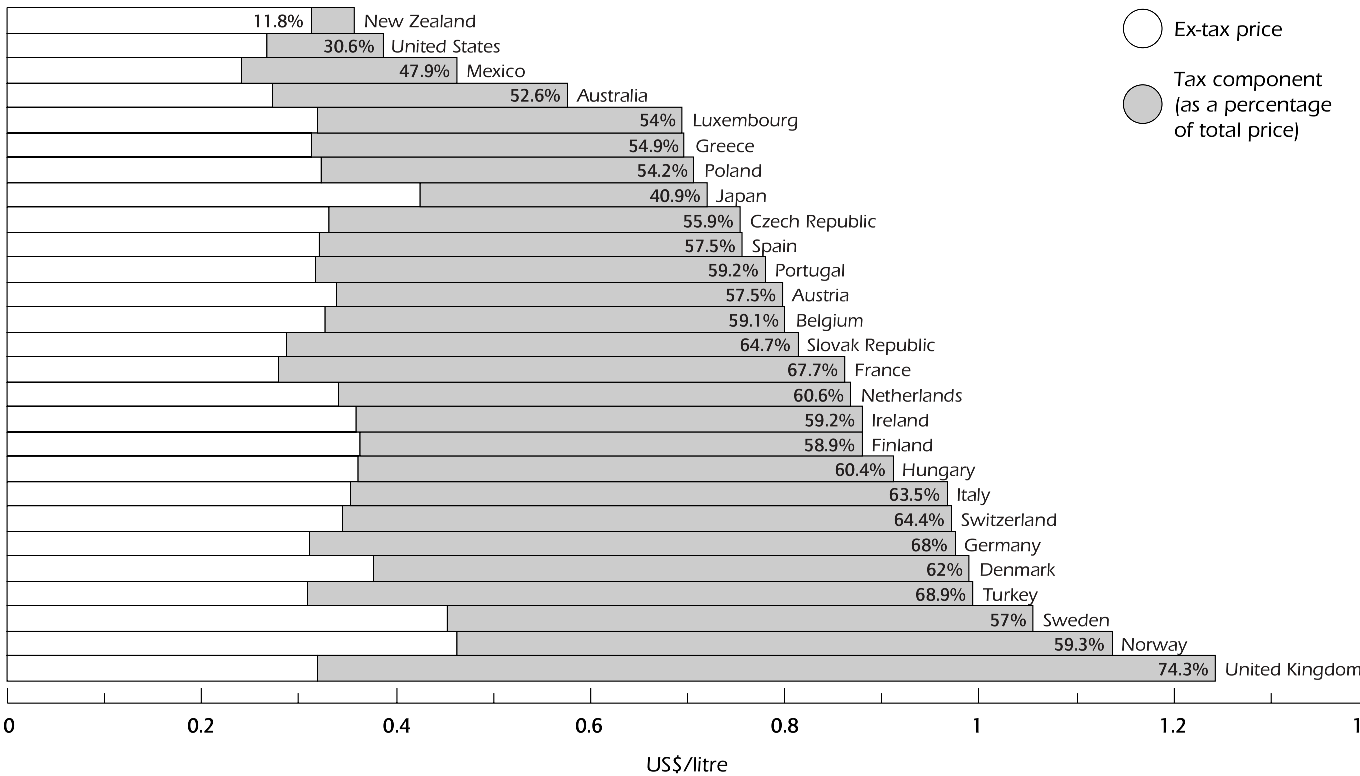
## OECD Unleaded Gasoline Prices and Taxes, Third Quarter 2003




Note: data not available for Korea.
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Figure 6

**OECD Automotive Diesel Prices and Taxes, Third Quarter 2003**

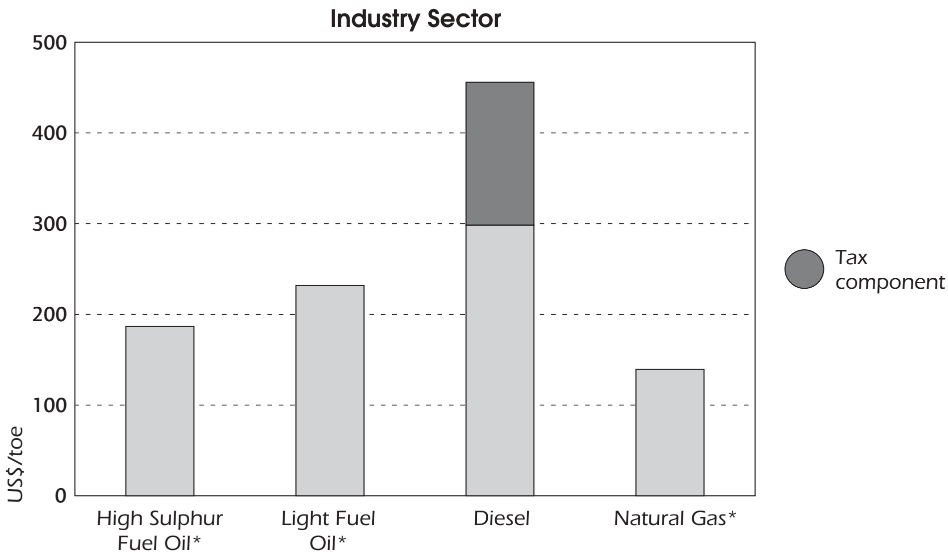


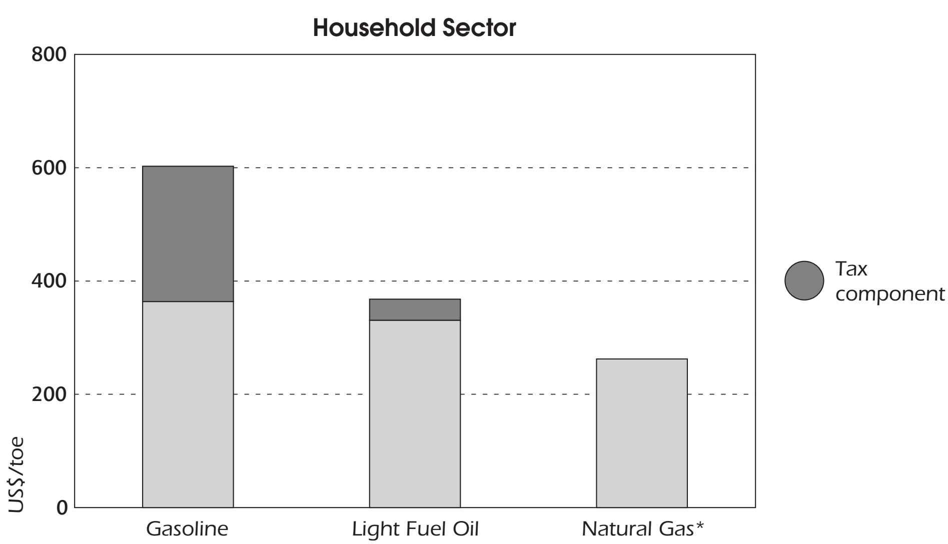

Note: data not available for Canada and Korea.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

Figure 7

## Fuel Prices, 2002




* tax information not available.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

As is the case for most of Canada's business sectors, the energy sector is subject to the rules of the federal Income Tax Act for corporate income taxes, and the Excise Tax Act for the Goods & Services Tax (GST). The GST is a 7% value-added tax applied to most goods and services consumed domestically (*i.e.* exports are not subject to the GST). The availability of input tax credits in the GST regime essentially eliminates this tax on most business inputs. The provinces have their own corporate income and sales tax rates. However, there are some features which are unique to energy. For example:

- Under the Canadian constitution, provincial Crown-owned power utilities are exempt from federal income tax. This exemption is removed in the event of privatisation.
- Upstream oil and gas sectors have access to the Resource Allowance, a special deduction to compensate for the fact that provincial royalties are not deductible from income in calculating federal business income taxes. The 2003 federal budget announced the government's intention to phase out the Resource Allowance and phase in royalty deductibility over the next five years.
- The oil and gas industries also benefit from special deductions in the form of accelerated write-offs and the right to issue flow-through shares on their exploration and development expenditures[3].
- Certain types of energy efficiency and renewable energy investments are eligible for similar high tax write-off rates for environmental reasons under accelerated capital cost allowance Class 43.1 and the Canadian Renewable and Conservation Expense (CRCE). CRCE can also be financed under flow-through share agreements.
- The federal government imposes excise taxes on conventional transportation fuels. The federal excise tax on motor gasoline and diesel stands at 10 cents and 4 cents per litre, respectively. Alternative transportation fuels (*i.e.* ethanol, methanol, propane and natural gas) are exempt from these taxes. This is a subsidy to alternative fuels although they remain subject to the GST. Provincial taxes on motor fuels are generally higher than the federal ones and often apply to alternative fuels as well.

## CRITIQUE

Endowed with abundant natural resources, Canada is among the world's largest producers of most types of energy, oil (ninth rank in 2002) and

3. A flow-through share is a share issued by an oil, gas or mining company to finance development and exploration work. The money raised on public and private capital markets is generally the main source of financing for junior mining companies. Flow-through shares offer tax deductions for the purchaser: all provinces other that Québec follow the federal rules regarding exploration (100% deductibility) and development (30% deductibility).

products (eighth), gas (third) and hydroelectricity (first). Canada is also one of the IEA's largest exporters of energy (oil and products, coal, gas and electricity).

Canada is a very large country with a harsh climate in some areas. Environmental awareness is high. The population is quite diverse, including aboriginal communities[4] and some people living in remote areas. There are marked differences in resource endowment between the provinces and territories. For example, fossil fuel production is concentrated in Alberta and is of major importance to the provincial economy. Nuclear production is concentrated in Ontario. Hydro production is important in a number of provinces, but notably in Québec. This situation has impacts on energy demand and supply and raises a number of challenges for energy policy formulation and implementation.

Canada's constitution provides responsibilities to the federal government with regard to energy that are limited to Canada lands[5], to international matters and inter-provincial issues. Further, under the authority of the constitution, Canada has used its declaratory power to assert jurisdiction over nuclear energy and the management of uranium resources. The federal government is responsible for promoting the overall economic development of Canada. It is also responsible for preserving national interests such as environmental protection or the reduction of provincial economic disparities. Provinces have more jurisdiction over energy than the sub-national governments of other federated countries in the IEA. Hence, delicate compromises required to satisfy diverse provincial interests related to specific topics (like climate change mitigation) have to be worked out. The only viable approach to address the most important energy policy challenges seems to be a process of intensive dialogue and consultation to achieve a national consensus on the goals and means of energy policies. Such a consensus could take many forms, ranging from implicit agreements on certain issues, the formulation of a joint "energy vision", to explicit *ad hoc* arrangements between federal and provincial governments on specific issues. Topics that may be of mutual interest are: implementation and co-ordination of climate change mitigation policies, streamlining of regulatory regimes and expansion of inter-provincial electricity interconnections and R&D. Where applicable, the utilisation of fiscal and regulatory instruments within federal jurisdiction could be explored to this end. As such a consultation takes time, emergency-related issues may be excluded.

To foster the development of Canada's energy sector in the coming decade, large investments are needed in oil sands, gas pipelines, electricity generation and transmission. Many of these new investments will take place in newer

4. Amongst Aboriginal people are First Nations, who have Indian ethnic origins. Aboriginal communities encompass Inuit, Métis as well as Indian peoples.
5. Canada lands are defined as lands that are outside the boundaries of the provinces, *i.e.* territorial lands, offshore, national parks, etc.

areas, such as northern Canada and offshore. Some concerns have been raised by the Canadian oil and gas industries on the investment and regulatory climate, pointing to possible higher constraints faced by investors in Canada compared to similar investments made in the US (for example in developing oil pipelines). The Canadian government has recognised the need to improve the regulatory situation, for example by creating a senior advisory committee on "Smart Regulation". Efforts to improve the situation may have to be pursued.

The lack of availability of published energy data in Canada shows an inability to give a comprehensive picture of the energy supply and demand situation. This is due to the complex network of information gathering which tends to delay energy information collection. The situation is improving but for some time, the federal government favoured quality of data over timeliness. This is the case, for example, for monthly oil and gas data, which, for the past few years, have been published with a few months delay compared to other IEA countries, with negative impacts on oil data transparency. Another reason for this difficulty is the protection of confidential industry data for which the federal government, and more specifically Statistics Canada, is prohibited by law (the Privacy Act) from releasing any information that identifies or could be used to identify an individual, business or organisation. StatsCan is allowed to disclose identifiable information when the respondent has given consent. For example, this affects directly the availability of coal production and consumption data. Similarly, unavailability of recent capacity data for electricity generating plants (including facilities using renewables) results in difficulties in assessing the overall generating capacity of the country. Another example of confidentiality of data is orimulsion, which is only used by one plant. The lack of figures on this fuel leads to difficulties in the calculation of energy balances and the derived $CO_2$ emissions. Data on coal and electricity prices have not been reported to the IEA for a few years. In the interest of market transparency, the Canadian administration should explore how this information can be made in the future without raising issues of confidentiality.

## RECOMMENDATIONS

*The government of Canada should:*

- *Take a more active role in initiating co-operation between federal, provincial and territorial governments with a view to formulating national consensus on the goals and implementation of energy policies, where mutually beneficial,* e.g. *through the Council of Energy Ministers and bilateral and regional meetings of ministers and high officials. Where applicable, the utilisation of the fiscal and regulatory instruments within federal jurisdiction could be explored to this end.*

- *Continue to ensure that the fiscal and regulatory environment is sufficiently competitive on an international basis to bring forward the necessary investment in the energy sector.*

- *Review energy data-reporting mechanisms to enable timely and comprehensive supply of data to policy-makers, analysts and international organisations.*

## GREENHOUSE GAS EMISSIONS

Canada's GHG emissions from energy combustion reached 519 Mt $CO_2$-equivalent in 2001, more than 20% above the 1990 level. $CO_2$ emissions[6] from energy production and use represent more than three-quarters of the total Canadian GHG emissions in 2001. Large final emitters (oil and gas production, smelting and refining, iron and steel, electricity generation) produce more than half of Canada's total greenhouse gas emissions. High population and economic growth leading to strong demand for transport fuels and electricity, added to the expansion of $CO_2$ emissions-intensive sectors such as oil sand production, are responsible for the current growth in $CO_2$ emissions. During the 1990s, a third of Canada's annual increase in GHG emissions was due to expanded energy exports (accounting for an additional 46 Mt $CO_2$). Representing one-quarter of the total energy-related emissions, public electricity and heat production experienced emission growth of 38% between 1990 and 2001. Emissions from other energy industries (including energy used by the extractive industries, the oil sand sector and the refining industries) represented 11% of total energy-related emissions in 2001[7], and grew by almost 34% since 1990. Emissions from the manufacturing sector stabilised over the same period, in spite of the construction sector (a sub-set of the manufacturing sector) having emissions that grew by more than 12%. Emissions from the residential sector decreased slightly by 3.6%. Emissions from the transport sector grew by 19%.

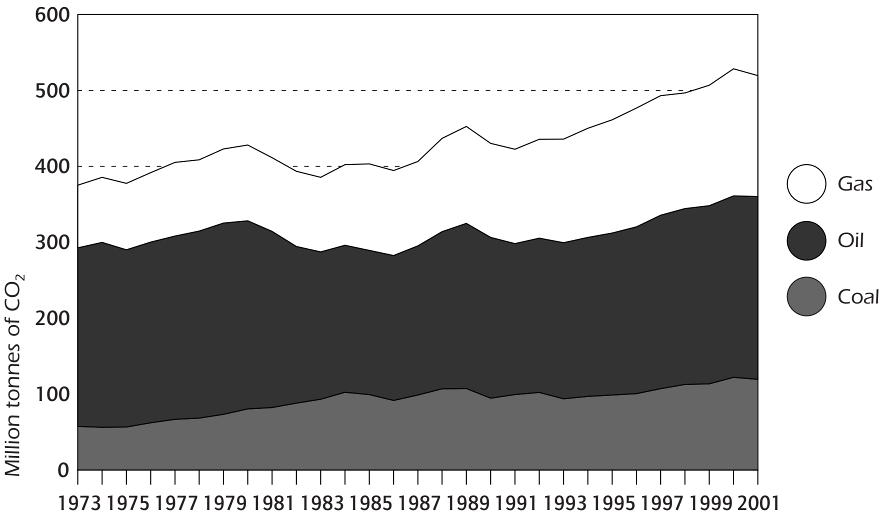
The effects of a warming climate are already evident in many parts of Canada through the reduction in sea ice and glacier cover and increased melting of permafrost. In addition, a number of recent events, including heat waves in southern Ontario, severe drought on the prairies, ice storms in eastern Canada, flooding in Manitoba, Québec and Newfoundland, forest fires and pest infestations in British Columbia, serve to highlight Canada's vulnerability to climate change. Many of these events have important implications for the energy sector.

Emissions vary significantly between provinces and territories, on account of the differences in energy use and production, as well as population and

6. $CO_2$ refers systematically to $CO_2$-equivalent emissions in the text.
7. Their share is more than twice as large in Canada than in OECD countries on average.

## Figure 8

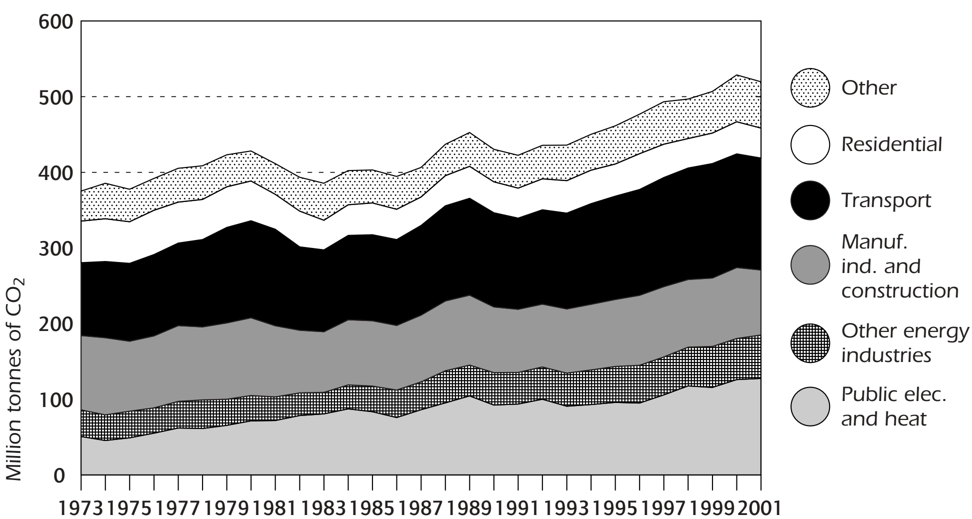
### $CO_2$ Emissions by Fuel*, 1973 to 2001




* estimated using the IPCC Sectoral Approach.
Source: *$CO_2$ Emissions from Fuel Combustion*, IEA/OECD Paris, 2003.

## Figure 9

### $CO_2$ Emissions by Sector*, 1973 to 2001



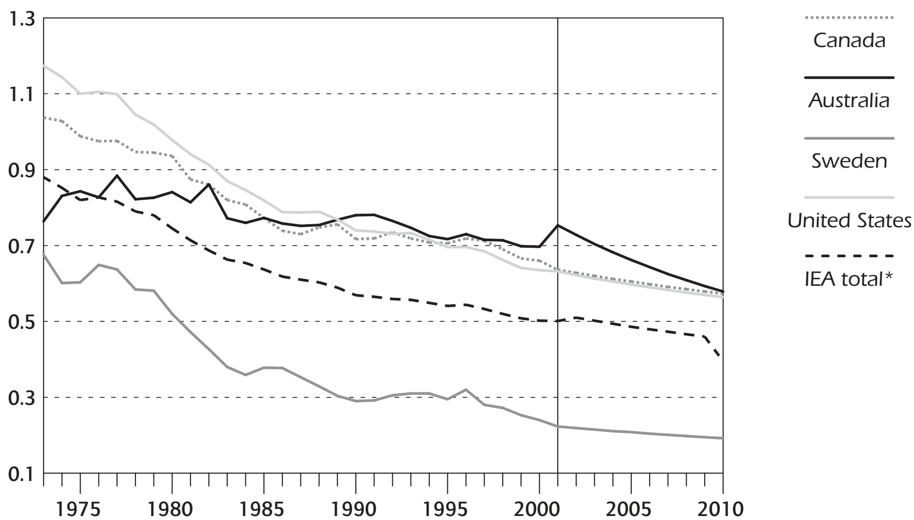

* estimated using the IPCC Sectoral Approach.
Source: *$CO_2$ Emissions from Fuel Combustion*, IEA/OECD Paris, 2003.

manufacturing activities. The two largest emitters are Alberta and Ontario, mainly because of oil and gas production in the former (including oil sands) and electricity produced from coal in the latter. Regional disparities in emission levels could increase substantially with further development of oil sands in Alberta, where production could increase by a factor of five over the coming decade. Although the oil sands sector has already reduced its emission intensity by 26% over 1990-2000[8] and there are still expectations for further improvements, emissions per unit of synthetic crude oil produced will remain 2 to 4 times higher than for conventional crude oil.

**Figure 10**

**Energy-related $CO_2$ Emissions per GDP in Canada and in Other Selected IEA Countries, 1973 to 2010**

($CO_2$ emissions/GDP using 1995 prices and purchasing power parities)




* excluding Japan, Korea and Norway from 2002 to 2010.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; *National Accounts of OECD Countries*, OECD Paris, 2003; and country submissions.

8. In 2001, energy consumed per cubic metre of crude oil produced from oil sands was 8.68 GJ, which is 20% less than the 1990 level (source: *Canadian Industry Program for Energy Conservation 2001/2002 Annual Report*, Office of Energy Efficiency, Ottawa).

Table 6

**Total Energy-related GHG Emissions in Provinces and Territories**

($Mt\ CO_2$-equivalent, 2001)

| *Provinces and territories* | *GHG emissions* |
|---|---|
| Newfoundland and Labrador | 9.0 |
| Prince Edward Island | 1.6 |
| Nova Scotia | 19.3 |
| New Brunswick | 21.3 |
| Québec | 61.2 |
| Ontario | 163.3 |
| Manitoba | 12.1 |
| Saskatchewan | 47.5 |
| Alberta | 191.8 |
| British Columbia | 53.9 |
| Yukon, Northwest Territories, Nunavut | 3.0 |
| **Total** | **584.0** |

Note: the difference between the sum of provincial emissions in this table and the 519 Mt figure mentioned in the text is due to the fact that IEA total energy emissions do not account for fugitive emissions and emissions from pipeline fuels.

Source: Environment Canada.

## *CLIMATE CHANGE MITIGATION POLICIES*

By ratifying the Kyoto Protocol in December 2002, the government of Canada committed to reduce overall emissions of greenhouse gases to 6% below 1990 levels between 2008 and 2012. Canada's emissions projections under business-as-usual scenario indicate that the emissions will reach 33% above the 1990 level in 2010, which will make the gap to the Kyoto target approximately 240 Mt in the Kyoto period.

The government of Canada has committed $3.7 billion of investment on climate change-related activities since 1998, including $2 billion announced in Budget 2003. $300 million has been allocated as part of the budget to external foundations working on climate science and the demonstration of environmental technologies; a further $1 billion was allocated in August 2003 to various federal initiatives related to GHG mitigation and the development of new emissions reduction technologies. The Climate Change Plan for Canada, released in November 2002, sets out Canada's framework and priorities in meeting the Kyoto target. The Climate Change Plan for Canada encompasses earlier climate change initiatives (see box). Priority areas include transportation, housing and commercial/institutional buildings, large industrial emitters, small and medium-sized enterprises, and the international market.

The plan includes a large allocation of funding for the development and diffusion of energy-processing technologies (including renewables), and also focuses on improving energy efficiency. As part of the measures taken before the Climate Change Plan was the Action Plan 2000 on Climate Change, initiated in 2000. Action Plan 2000 on Climate Change is a horizontally-managed initiative led by Natural Resources Canada and Environment Canada, and involves seven federal departments and 45 specific measures in distinct but interrelated sectors. The five-year $500 million Action Plan 2000 on Climate Change targeted key emitting sectors and is expected to achieve an estimated reduction of 65 Mt of $CO_2$ by 2010. While focused primarily on GHG mitigation, Action Plan 2000 on Climate Change also promoted knowledge progress and foundation-building in climate science, impacts and adaptation, northern and Aboriginal communities and technological innovation.

In addition, part of earlier measures, the 2000 federal budget included a component to replenish the Climate Change Action Fund (CCAF) – announced initially in the 1998 Budget – with an additional investment of $150 million over three years. The mandate includes five integrated components: building for the future; international policy and related activities, and several initiatives such as Technology Early Action Measures (TEAM), Science, Impacts and Adaptation (SIA) and Public Education and Outreach (PEO).

An important component of the Climate Change Plan for Canada are voluntary undertakings (for example by industry) registered with Canada's Voluntary Challenge & Registry Inc (VCR Inc.)[9]. The Climate Change Voluntary Challenge & Registry was established in 1994 and privatised in October 1997. The organisation registers voluntary commitments to reduce GHG emissions. In April 2004, there were 1 239 organisations registered at VCR Inc.

Co-ordination of environment and energy policy is undertaken through a number of consultative processes. For example, NRCan, Environment Canada and the National Climate Change Secretariat are currently meeting with stakeholders, industry, NGOs, provinces and territories in various forums to discuss implementation of the National Climate Change Plan for Canada. They are also trying to develop memoranda of understanding to agree to areas of priority to address climate change. A high-level group of officials within NRCan currently consulting with large final emitters is responsible for negotiating covenants on specific emissions reduction targets. There are also a number of working groups on climate change issues such as technology, forest sinks, electricity transmission, renewable energy, impacts and adaptations, and transportation.

The government created the Clean Development Mechanism and Joint Implementation Office within the Department of Foreign Affairs and

9. The Internet site for Voluntary Challenge & Registry Inc. is www.vcr-mvr.ca.

International Trade in 1998. This office negotiates bilateral agreements with countries hosting emissions mitigation projects, secures project approvals and provides technical and funding assistance for market identification studies, feasibility assessments, baselines and monitoring plans, risk assessments and environmental impact studies. Canadian companies are active players in the international market for carbon emissions permits.

## The Climate Change Plan for Canada

The Climate Change Plan for Canada, released in November 2002, outlined Canada's forecasted 240 Mt emissions reduction goal into a three-step approach: (1) Actions Underway (80 Mt); (2) New Actions (100 Mt); and (3) the Remainder (60 Mt).

*Step one* is comprised of actions that are under way, including those on transportation and buildings (estimated to reduce GHG emissions by 13 Mt) such as negotiations for 25% improvement in new vehicle fuel efficiency by 2010 and negotiations of voluntary agreements with air, rail, truck transport and marine sectors to improve fuel efficiency of goods transport; actions by large final emitters and other industrial emitters (25 Mt), agriculture, forestry and landfills; sinks and offsets[10] (38 Mt), and reductions acquired on the international market (2 Mt).

Many of these actions are being carried out in partnership with the provinces, territories and private sector and have been in operation for less than a year. An assessment of their effectiveness has been initiated. If required, resources will be shifted away from initiatives that are not meeting expectations into areas that have the potential to be more effective.

*Step two* proposes new measures in the following areas: more actions by Canadians and governments in the transportation and buildings sectors (15-20 Mt) such as increased use of public transit and sustainable urban planning; Large Final Emitters system, including reductions of emissions by industry through targets established under covenants with a regulatory or financial backstop, domestic emissions trading with access to domestic offset credits and the international carbon market (55 Mt), as well as strategic investments in renewable energy, technology and infrastructure (16 Mt); and more active government participation in the international market for emission permits (public purchases of a minimum 10 Mt). Together, these actions are estimated to result in approximately 100 Mt reductions in GHG emissions.

10. Offset credits are emissions reductions obtained in a sector (*e.g.* agriculture, forest and possibly landfills not covered by the Large Final Emitters system) that could be sold to industry, thus offsetting emissions generated by industries under the Large Final Emitters system.

*Step three* covers the remaining gap and puts forward a number of options that could be used, for example: an "opportunities envelope" for working with the provinces, territories and municipalities, Aboriginal communities, private sector and non-governmental organisations as well as infrastructure funding (20-30 Mt); existing and future technology R&D investments that produce emissions reductions (10 Mt); provincial and territorial actions under way not involving federal partnerships (10-20 Mt); community-wide emissions reduction plans by 100 municipalities (10 Mt); a challenge to Canadians to reduce emissions by 1 tonne each (7 Mt); and credits for cleaner energy exports (up to 70 Mt)[11].

Implementation of steps 2 and 3 has begun with the federal initiatives announced as a result of the Budget 2003 funding.

Table 7

**Overview of the Three Steps Envisaged under the Climate Change Plan**

| | | |
|---|---|---|
| Step 1: Actions Underway | 80 Mt | Action Plan 2000<br>Budget 2001 measures<br>Business-as-usual sinks<br>International market |
| Step 2: New Actions | 100 Mt | Large Final Emitters system<br>New targeted measures<br>International purchases or projects (CDM, JI, etc.) |
| Step 3: The Remainder | 60 Mt | To be determined |

The Large Final Emitters Group was established in late 2002 to facilitate annual greenhouse gas emissions reductions in key emitting industrial sectors. One of the key instruments of the Climate Change Plan for Canada is the proposed introduction of a set of negotiated emissions reduction targets to address emissions from Large Final Emitters.

Within these sectors, specific measures are not prescribed and individual firms will be responsible for implementing measures and/or purchasing permits in order to comply with their targets. The trading scheme will cover companies in

11. This proposal put forward by Canada in the international negotiations to implement the UNFCCC is to obtain credits for its exports of hydroelectricity and natural gas to the US that reduce emissions in the US. However, to date, other countries did not accept this proposal.

sectors representing about half of total projected emissions in 2010. The system proposes a general target for emissions reductions of 15% below business-as-usual. The federal government committed that the targeted emissions reduction from large industrial emitters will not exceed 55 Mt. To define targets, an emissions intensity approach will be used rather than a cap on emissions. Targets depend on specific circumstances and will be defined per company or per sector.

The system also introduces a cap on carbon price of $15 per tonne of $CO_2$, ensuring that final emitters will be able to meet their compliance obligations at a cost no greater than this limit. The federal government will be responsible to make up any difference between the 55 Mt target and actual emissions reductions through other domestic emissions reductions or the purchase of international emission permits. Given the importance of energy-intensive industry to Canadian GDP, the federal government has been rather cautious in its efforts, systematically putting forward its willingness to minimise the compliance burden on industry. An agreement on the principle of introducing such a trading system was signed between representatives of the industry and the federal government in October 2003. The trading system is projected to be introduced at the end of 2006. A number of important issues such as target allocation, compliance mechanisms and measurement, reporting and verification protocols were still to be determined at the time of writing this report in early 2004.

## Sectors Proposed for Inclusion on the Basis of Emissions Intensity

- Thermal electricity production (coal, oil and gas)
- Oil and gas (upstream extraction, oil and gas pipelines, gas utilities, petroleum refining)
- Mining (both metal and non-metal)
- Pulp and paper production
- Chemical production (industrial inorganic and organic chemicals, and chemical fertilisers and fertiliser materials)
- Iron and steel production
- Smelting and refining
- Cement and lime production
- Glass and cement container production

The Climate Change Plan gives a sense of the possible order of magnitude of impacts on industry, estimating the direct costs of such mitigation for selected industries. The results show that the costs are generally minor, with significant costs in a few energy industries (see Table 8)[12].

Table 8

**Estimated Mitigation Costs for Selected Energy Industries in 2010**

(cost as % of unit price, with 85% free permit allocation and a carbon price of $10 per tonne of $CO_2$)

| *Sector* | *%* |
|---|---|
| Conventional oil | 0.09 |
| Heavy crude oil | 0.05 |
| Oil sands bitumen | 0.34 |
| Oil sands crude oil | 0.31 |
| Natural gas | 0.14 |
| Refined petroleum products | 0.03 |
| Electricity coal | 1.94 |
| Electricity oil | 1.57 |
| Electricity gas | 0.60 |

Source: Climate Change Plan for Canada.

In terms of quantifying costs, the federal government generally does not calculate externalities, either positive or negative, on a programme-by-programme basis. The federal government does examine the externalities more qualitatively, however, in terms of their contributions not only to GHG emissions reductions but also as the contributions of programmes to various government objectives, environmental or other, such as the reduction of traffic congestion or the development of liveable cities. This can lead to the choice of policies that, on a cost-per-tonne basis, are modestly effective, but that may bring about a variety of positive externalities.

In the February 2004 Speech from the Throne, the government of Canada stated its intention to respect its commitment to the Kyoto Protocol on climate change in a way that produces long-term results while maintaining a strong economy. The government announced that it would do so by developing an equitable national plan, in partnership with provincial and territorial governments and other stakeholders.

12. Other non-energy energy-intensive sectors such as lime or cement production could be more affected. The study estimates that mitigation costs would amount to 2.5% of the unit lime price and 1.2% of the unit cement price.

# OTHER ENVIRONMENTAL ISSUES

Air quality and local environment issues appear to be dealt with effectively by the federal and provincial governments. Natural resources in Canada, including those associated with energy production and end use, are primarily under provincial jurisdiction. Provinces have adhered to consensus decisions to meet environmental standards of operation, including for air quality and atmospheric emissions. Environment Canada is the lead federal department on these issues, and NRCan participates in the energy-related policies and activities. These policies involve a mix of regulations, economic instruments and voluntary measures and include the following pollutants:

- Particulate matter (PM) and ground-level Ozone ($O_3$).
- Sulphur dioxide ($SO_2$) and nitrogen oxides ($NO_x$).
- Volatile organic compounds (VOCs).
- Persistent organic pollutants (POPs).
- Atmospheric emissions of mercury.

## PARTICULATE MATTER (PM) AND GROUND-LEVEL OZONE ($O_3$)

Since 2000, an Ozone Annex has been added to the 1991 Canada and US Air Quality Agreement. This annex committed the parties to implement measures to reduce $NO_x$ and VOCs based on their domestic legislation. Both Canada and the US are currently evaluating the feasibility of adding a particulate matter annex in 2005.

Particulate matter less than or equal to 10 microns (PM10) was added to the List of Toxic Substances in Schedule 1 of the Canadian Environmental Protection Act in May 2001. Future risk management strategies will focus on reductions in the precursors.

The Canada-Wide Standards (CWS) for particulate matter less than or equal to 2.5 microns (PM2.5) and ozone were endorsed in 2000 under the Canada-Wide Agreement on Environmental Harmonization.

In 2001, Canada published the Interim Plan 2001 on Particulate Matter and Ozone which identifies strategies proposed by the government to meet its commitments under the CWS process. The federal government is also working with provincial and territorial governments to engage industries in a multi-pollutant emissions reduction approach, addressing smog precursor emissions.

The Cleaner Vehicles and Fuels Agenda is a federal strategy identified in the Interim Plan on PM and Ozone to develop emission standards aligned with the United States.

- New On-road Vehicle and Engine Emission Regulations have phased in more stringent national emission standards and a new regulatory framework under the Canadian Environmental Protection Act 1999 beginning on 1 January 2004. When fully phased in in 2009, the regulations will subject all cars and light-duty trucks to the same set of stringent emission standards.
- Emissions regulations for off-road engines and vehicles are currently being developed under the Canadian Environmental Protection Act 1999.
- New regulations will reduce the sulphur content in on-road diesel fuel to 15 parts per million (ppm) in mid-2006.
- In 1999, the federal government passed the Sulphur in Gasoline Regulation which states that starting in 2005, low-sulphur gasoline (less than 30 ppm) will be required throughout Canada. As an interim step, gasoline must meet an average sulphur level of not more than 150 ppm during the phase-in period of 1 July 2002 to 31 December 2004.
- The Benzene in Gasoline Regulations control the level of benzene in gasoline to 1% by volume.

## SULPHUR DIOXIDE ($SO_2$) AND NITROGEN OXIDES ($NO_x$)

The Canada and US Air Quality Agreement commits both countries to address transboundary air pollution, primarily $SO_2$ and $NO_x$. In May 2003, the two countries announced pilot projects to further increase their collaboration in order to meet the agreed goals.

The Canada-Wide Acid Rain Strategy for Post-2000 provides the framework to achieve further reductions in emissions in $SO_2$ and $NO_x$ in Eastern Canada, including identification of critical loads for acid deposition, additional science, as well as monitoring and reporting on results achieved.

Under the CWS for PM and ozone, the federal government is working with the provincial and territorial governments to engage industries in a multi-pollutant emissions reduction approach.

## VOLATILE ORGANIC COMPOUNDS (VOCs)

There are no federal regulations regarding VOCs emissions from stationary sources. However, a number of national guidelines, codes of practice or standards for the reduction of VOC emissions were developed under the 1990

Canadian Council of Ministers of the Environment (CCME) $NO_x$/VOCs Management Plan. Provinces use the guidelines, code of practice or standards as the basis for provincial measures for the reduction of VOCs emissions from stationary sources.

National standards and guidelines are currently being developed for the reduction of VOCs for the wood furniture sector and have been developed for the reduction of VOCs from industrial maintenance coatings and Canadian automotive parts coating operations.

A ten-year federal plan is being developed to reduce VOCs emissions from consumer products, from the use of paints, solvents and other products in industrial or commercial processes.

## PERSISTENT ORGANIC POLLUTANTS (POPs)

The federal government manages POPs through the federal Toxic Substances Management Policy, the CCME Policy for the Management of Toxic Substances and the Canada-Wide Standards process under the Canada-Wide Agreement on Environmental Harmonization.

Provincial-territorial legislation and regulations limit the release of toxics to air, water and soil in their jurisdictions.

## ATMOSPHERIC EMISSIONS OF MERCURY

Canada-Wide Standards for incinerators and base metals smelters have been developed. A Canada-wide standard for mercury emissions from coal-fired electric power generation is currently under development.

Chlore-Alkali Mercury Release Regulations specify limits for releases to ambient air.

In addition to activities which are directed towards individual pollutants, the government of Canada is also examining innovative ways of managing air emissions. For example, the National Framework for Petroleum Refinery Emissions Reductions (NFPRER) led by the National Air Issues Coordinating Committee is currently developing a new approach to reduce emissions from the petroleum-refining sector. All levels of government, industry and non-governmental/health organisations are working together in order to provide principles and methods for various jurisdictions to establish facility emissions caps for their air pollutants and air toxics from petroleum refineries. Recommendations for performance based on environmental strategies are likely to be defined by spring 2004.

## CRITIQUE

The federal government should be commended for its efforts and achievements in formulating national climate change mitigation policies. Living up to Canada's commitment to Kyoto and at the same time ensuring continued growth of a competitive and innovative energy sector is the biggest single challenge for Canadian energy policy in the coming years. Although Canada is a major trading partner of the US which did not ratify the Kyoto Protocol, cost estimates calculated for the implementation of steps 1 and 2 of the Climate Change Plan show that the impact of climate change mitigation measures in terms of GDP loss for Canada as a whole may be manageable on a macroeconomic basis. The transition to a less emission-intensive economy will, however, negatively affect certain sectors and regions more than others, creating specific political and economic challenges.

The challenge is greater because of the rapid expansion of energy production and exports. Since some provinces are clearly more emission-intensive than others, it is not surprising that ratification of the Kyoto Protocol in December 2002 was carried out without unanimous support of the provinces. Alberta released a Climate Change Action Plan in October 2002 which focuses on an emissions intensity reduction approach and does not recognise the Kyoto Protocol framework or absolute emissions targets. The federal government is ultimately responsible for meeting Canada's Kyoto target. However, the majority of resource ownership and economic levers lie within the jurisdiction of the provinces and territories. The review team notes that co-operation between the federal and provincial stakeholders is essential if Canada is to move forward with climate change policy implementation and to ensure mutual benefits to the provinces and the country as a whole.

On the one hand, it is commendable that Canada takes a multi-step approach in its Climate Change Plan. On the other hand, the difference between the measures outlined in step 1 and those in steps 2 and 3 is not necessarily clear. The extent to which steps 2 and 3 of the Climate Change Plan are eventually going to lead to the expected emissions reductions is questionable considering the information available. Several measures depend on factors that are largely beyond the exclusive control of Canada for their design and implementation. This is the case, for example, for emissions reductions expected from improvements in the transport sector through more stringent vehicle fuel efficiency improvements, which will depend on the design and implementation of similar measures in the US.

The emissions trading system envisaged to help large emitters reduce their emissions is a move in the right direction. However, the trading system is yet to be implemented. Moreover, there is no guarantee that the industry will achieve the target of a 55 Mt emissions reduction. The burden of emissions reductions may eventually shift in part from the polluters to the federal government, with implications for every Canadian citizen. For climate change mitigation to move ahead and to keep up with the Kyoto commitment, emissions projections and analyses of envisaged mitigation measures need to be a policy priority. Also, more such efforts on a province-to-province basis need to be carried out and brought together in a consistent Canada-wide framework.

Last but not least, the extent to which policies and measures are necessary in addition to the trading system and the fact that they mesh well with the trading system does not seem to have been analysed thoroughly by the government.

Canada has a large range of policies and measures to address climate change. The federal government's climate change policy approach is largely based on fiscal and regulatory measures. The carbon price signal to Large Final Emitters under the covenant and trading scheme is limited because it is capped at $15 per tonne of carbon dioxide. This reflects the concern of the industrial sector that has to compete with the US industry which is not bound by Kyoto Protocol commitments. The energy sector in Canada is growing rapidly and major new infrastructure investments and energy resource developments will take place in the near future. It is important that the federal government ensures that companies are able to take into account likely future carbon dioxide emission requirements when making investment decisions. In this context, capping carbon prices could weaken such incentives for companies. Expanding or strengthening the carbon price signal could assist in achieving such an objective. There could be a possibility to reduce carbon cost by linking the domestic emissions trading system with other regions, including the European Union (EU).

Within the IEA member countries, Canada is in a unique and challenging situation with a strong commitment to climate change mitigation and large fossil fuel reserves currently being developed and large associated emissions growth. To facilitate a more sustainable development of its fossil fuel reserves, Canada needs to further its support to R&D to rapidly deploy low-emission technologies, and in particular carbon capture and storage technologies. The review team found that significant current industry and federal government efforts to develop these technologies focus essentially on sequestration techniques that lead to enhanced oil (or gas) recovery. Some efforts are directed towards $CO_2$ sequestration in oil sands and gas hydrates, and enhanced coal-bed methane recovery. Development of $CO_2$ capture technologies includes amine capture at the international test centre in Saskatchewan, $O_2/CO_2$ combustion and novel gasification techniques. Imposing a stronger carbon price could also assist in encouraging the deployment of conversion technologies, including carbon dioxide capture and storage, which may not develop in the absence of a strong price signal.

Air quality and local environment issues appear to be dealt with effectively by the federal and provincial governments. However, cumulative impacts of energy sector developments will need to be monitored closely, particularly in environmentally sensitive areas.

## RECOMMENDATIONS

*The government of Canada should:*

- *Increase co-operation with provinces and territories to implement the National Climate Change Plan, and in particular to develop the range of market incentives based on climate change policies. Promote the integration of energy and greenhouse policy objectives across federal and provincial governments.*
- *Undertake emissions projections and analyses for existing climate change measures as a matter of priority to allow adequate time for the identification of necessary further policies and measures.*
- *Investigate the possibility of strengthening and broadening the price signal for GHG emissions to ensure that new energy investment decisions reflect environmental considerations.*
- *Investigate further the potential of low emissions technology, and in particular $CO_2$ capture and storage, and the possibility of providing appropriate economic signals to encourage their development.*

## ENERGY CONSUMPTION

Canada is an energy-intensive country. Consumption of primary energy and electricity per unit of GDP or per capita is among the highest in the world. The total primary energy is 8 tonnes of oil equivalent (toe) and electricity consumption is 16.7 MWh per capita per annum, against 5 toe and 8.6 MWh respectively on average in the IEA. There are important structural reasons for such a large energy intensity of the Canadian economy: a high concentration of output in a few energy-intensive sectors (non-ferrous metals, pulp and paper, oil and gas), a very cold climate, high living standards with limited constraints on space occupation resulting in significant residential and commercial heating demand and large distances.

Final energy consumption in Canada has grown regularly in the past decade, less rapidly than the economy, showing signs of improved efficiency. Total final consumption (TFC) has grown from 161.3 Mtoe in 1990 to 195.4 Mtoe in 2002, or 1.8% per annum. Industry consumed 39.8% of TFC in 2002 and transport 27.4%. Residential and commercial sectors consumed the remaining one-third.

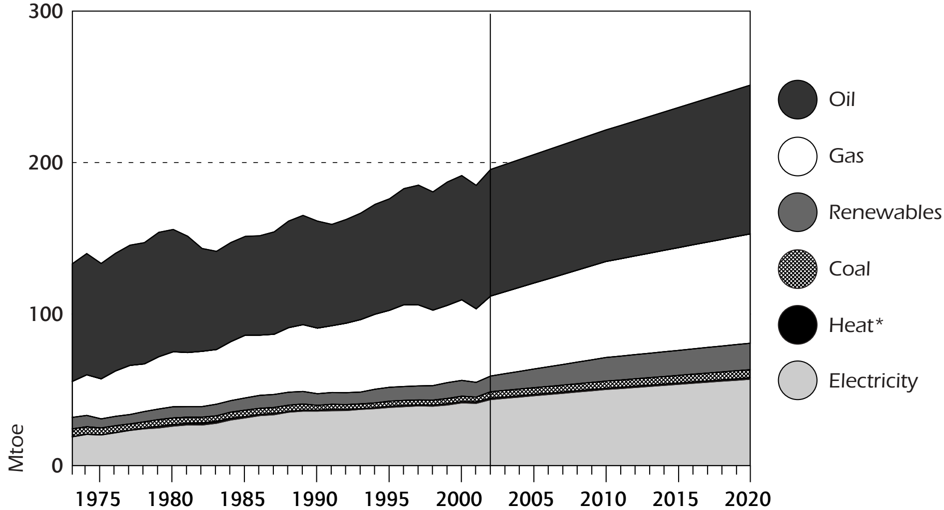
The federal government projects final consumption to grow at a more sustained rate in the decade ending in 2010, by 2.0% per annum (against 1.6% for TPES) and a further slow-down between 2010 and 2020, by 1.2% per annum (against 1.0% for TPES), projecting more efficiency gains in the latter part.

In 2003, the Office of Energy Efficiency (OEE) published *Energy Efficiency Trends in Canada: An Update*, its seventh annual review of energy efficiency in Canada, covering the period 1990-2001. This review tracks national trends in energy efficiency and their contribution to changes in energy use and related carbon dioxide emissions. The OEE Index measures performance in energy efficiency on a sector basis – separating the actual efficiency gains from the structural and physical changes affecting energy consumption. According to the OEE, final energy consumption grew by 16.7% in 1990-2001. Industrial activity increased by 36% during this period. The total residential floor space in Canada grew by 18%. The amount of commercial floor space increased by 24%. And there was a 14.7% growth in passenger-kilometre and a 37.1% increase in freight tonnes-kilometre. TPES per GDP unit decreased from 0.39 to 0.34 Mtoe and TFC per GDP unit from 0.30 to 0.25 Mtoe between 1990 and 2001. Structural changes in the economy have a responsibility in lowering growth, but the most important contributor is a significant improvement in actual efficiency reaching 9.4% between 1990 and 2000 (about 1% per year)[13].

13. See *Energy Efficiency Trends in Canada, 1990 to 2001*, Office of Energy Efficiency, NRCan, Ottawa, 2003.

## Figure 11

### Total Final Consumption by Source, 1973 to 2020

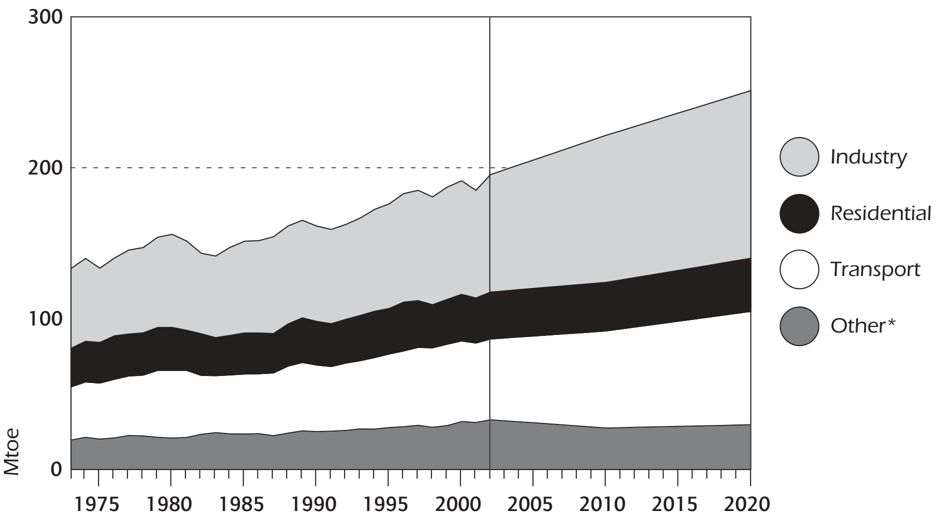



* negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

## Figure 12

### Total Final Consumption by Sector, 1973 to 2020

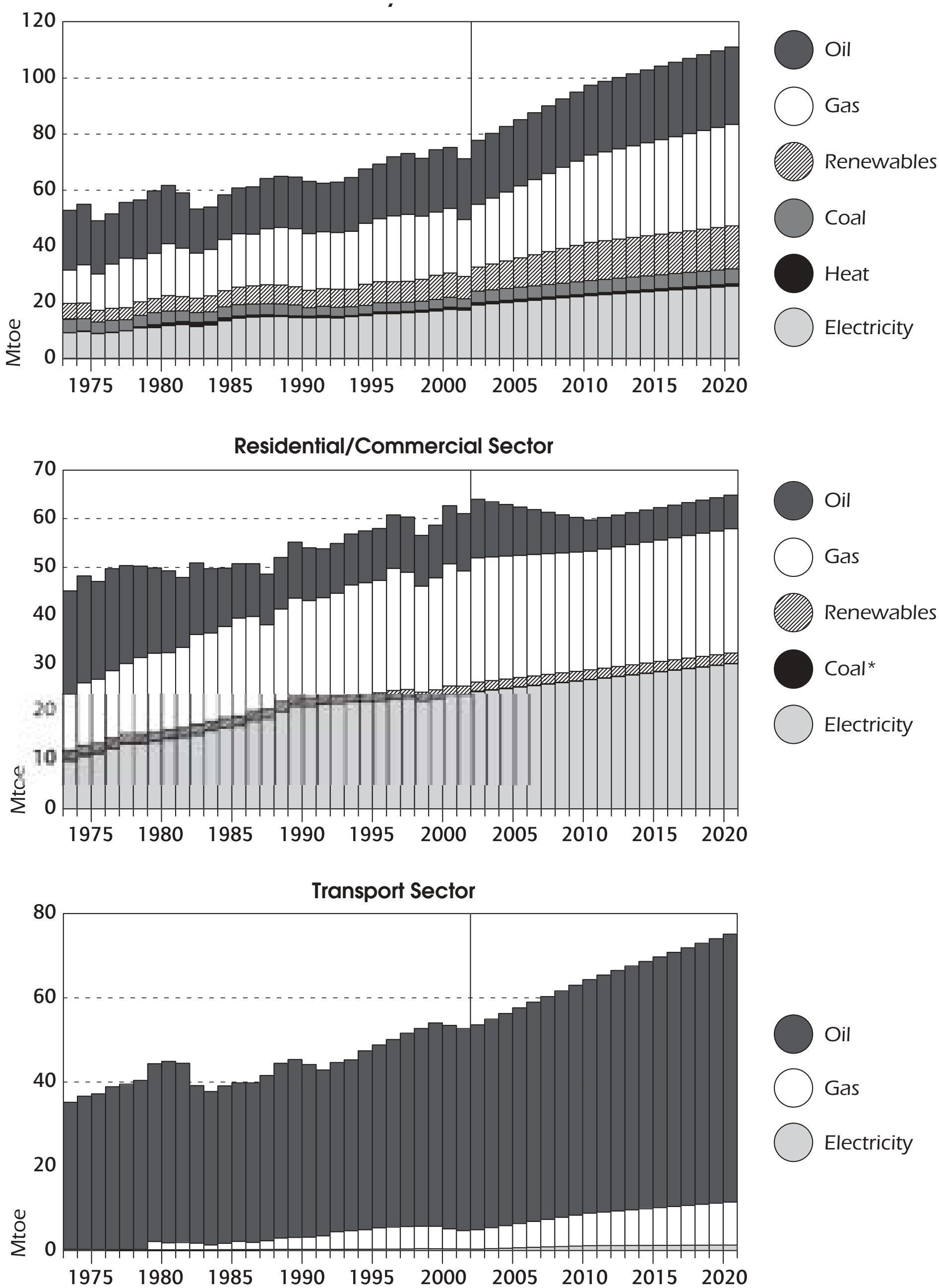



* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

Figure 13

**Total Final Consumption by Sector and by Source, 1973 to 2020**



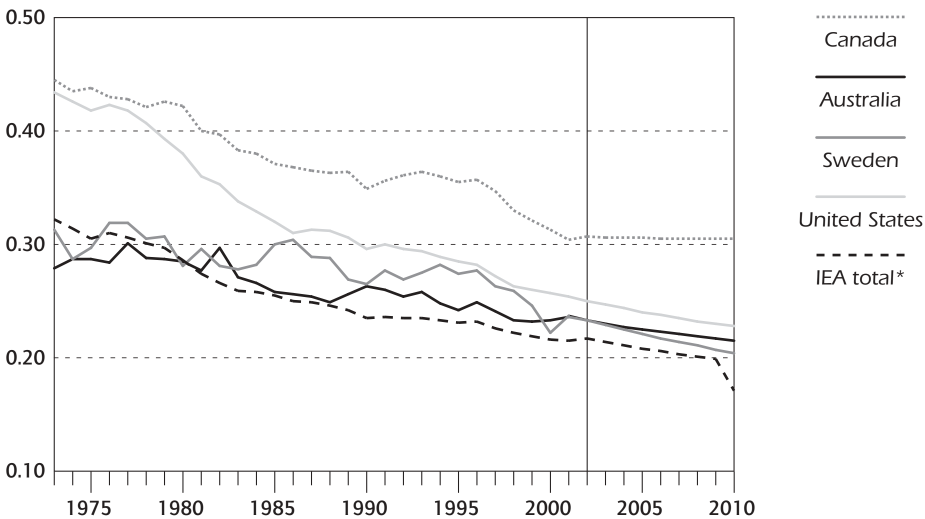

* negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

Figure 14

**Energy Intensity in Canada and in Other Selected IEA Countries, 1973 to 2010**

(toe per thousand US$ at 1995 prices and purchasing power parities)




* excluding Japan, Korea and Norway from 2002 to 2010.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; *National Accounts of OECD Countries*, OECD Paris, 2003; and country submissions.

## *ENERGY EFFICIENCY AND CONSERVATION POLICIES*[14]

Improving energy efficiency and increasing the use of alternative transportation fuels in order to limit GHG emissions and improving economic efficiency are strategic goals of the Canadian government. To do so, the federal government relies on policy instruments to overcome barriers of inadequate information and knowledge, institutional deterrents, and financial and economic constraints in the energy end-use market. Such policy tools are: leadership by example; information and awareness of energy-efficient products and practices; voluntary initiatives; financial incentives and regulations. These features are reflected in the Energy Efficiency Act passed in 1993. The federal government has authority over:

- Regulation of energy performance levels of energy-using products (including windows and doors) that are imported or shipped between provinces.

14. See also the IEA *Energy Efficiency Update* on Italy, http://www.iea.org/pubs/newslett/eneeff/it.pdf

- Energy labelling of these products.
- Collection of statistics and information on energy use and alternative energy.

The government of Canada manages programmes in all energy end-use sectors through the Office of Energy Efficiency, created in 1998 and operating under NRCan. Provincial and territorial governments, municipalities, utilities, as well as some non-governmental organisations also contribute to energy efficiency policies though their own set of programmes. The acceleration in formulating and implementing climate change mitigation policies has provided a new stimulus to energy efficiency policies since the late 1990s and in the early 2000s, and has reinforced co-operation between NRCan and Environment Canada to implement energy efficiency policies.

With the Action Plan 2000 on Climate Change released in 2000, the government of Canada calculated potential emissions reductions from existing programmes of energy efficiency. These estimates were included in the Climate Change Plan of 2002. Canadian Industry Program for Energy Conservation (CIPEC) – see below for more information on the programmes mentioned here – is targeted to cumulatively reduce GHG emissions by 4.1 Mt by 2006, and by 5.8 Mt by 2010. The EnerGuide for Houses Initiative has set a long-term GHG reduction target of 2.5 tonnes per house per year. The Energy Efficiency Standards Initiative is targeting a 29 Mt of $CO_2$ reduction annually by 2020. The Equipment Labeling Program envisages a 1.1 Mt annual reduction in 2006, and 2.8 Mt by 2010. The Commercial Vehicles Initiative aims at reducing GHG emissions in the freight sector by 2 Mt by 2010.

Changes in energy efficiency in the economy are tracked using the OEE Index mentioned earlier, which has been developed with factorisation methodology. Annual assessments of trends in energy use are published in the technical report *Energy Efficiency Trends in Canada*. The government of Canada has also developed the National Energy Use Database (NEUD) that provides a reliable and comprehensive source of information on energy consumption in all sectors of the Canadian economy. The government of Canada maintains the *Directory of Energy Efficiency and Alternative Energy Programs in Canada*. The directory is an inventory of programmes to promote the efficient use or conservation of energy at the end-use level and/or the use of alternative energy in Canada. As part of non-official monitoring of efficiency efforts, the Canadian Energy Efficiency Alliance, a non-governmental organisation, publishes annually a national report card on energy efficiency that rates federal and provincial governments according to the level of support and continuity of their energy efficiency action (see Table 9).

Since the federal government has limited jurisdiction over energy matters, provincial policy measures have an important role. Provincial and territorial end-use policies, including collaboration with federal programmes, vary significantly

Table 9

## Main Provincial and Territorial Energy Efficiency Policies, 2002

| *Provinces and territories* | *Main policies* |
|---|---|
| Newfoundland/Labrador | Government focuses on improving energy efficiency in its own facilities through energy performance contracting for renovation of its building stock. |
| Prince Edward Island | Training and on-site energy analysis for the industry through the government-led $MART Energy Management Program. Deployment of similar efforts towards residential and commercial sectors. |
| Nova Scotia | Regulations and energy standards for new buildings, particularly public ones. |
| New Brunswick | Wide range of recommendations on energy efficiency implemented through electricity market reform policy, climate change mitigation policies. |
| Québec | Wide range of sectoral energy efficiency programmes associated to targets and assigned budgets, implemented by the Agence de l'Efficacité Energétique du Québec. Expansion of the product range falling under efficiency standards and labels. Mandatory adoption of the Model National Building Code for Buildings by municipalities. Demand-side management programmes offered by gas and electricity distributors. |
| Ontario | Canada's largest number of products regulated for minimum energy efficiency levels. Regulation promoting energy efficiency in the gas industry, beginning to be applied to the electricity industry. |
| Manitoba | Reduction of government-led energy efficiency measures, compensated by mandate given to Manitoba Hydro to deliver gas and electricity efficiency programmes. |
| Saskatchewan | Creation of an Energy Conservation Office. |
| Alberta | Efficiency measures mostly carried out as part of climate change mitigation efforts. Newly created Energy Efficiency Office to deliver information on efficiency measures. |
| British Columbia | Regulation of energy efficiency through a provincial Energy Efficiency Act and the British Columbia Building Code. Gradual reduction of public budget, compensated by growing role of BC Hydro in delivering energy efficiency programmes. Renewed emphasis on efficiency and conservation measures in the 2002 Energy Plan. |
| Yukon, Northwest Territories, Nunavut | Wide range of efficiency support measures to involve all energy stakeholders in partnerships in yielding efficiency gains, through regulation, and third-party involvement in Yukon and Northwest Territories. |

Source: Compiled from Canadian Energy Efficiency Alliance, *National Report Card on Energy Efficiency 2002*.

across provinces and territories. Generally, provincial governments focus on energy supply issues and, apart from energy efficiency regulation of products, they appear to use and promote end-use initiatives – including those developed by the federal government – only to a limited extent (see Table 9).

## INDUSTRY

In spite of efficiency gains, the federal government projects final consumption from industry to grow significantly to 111 Mtoe by 2020, or a 5% per annum increase, which is approximately twice as large as the projected economic growth. If energy upstream activities and power production are subtracted from the total industrial final energy consumption, the projected growth is slightly above 1% per annum.

Industry, including forestry, mining, manufacturing and construction, is the largest final energy-consuming sector. Energy consumed by the petroleum refining, iron and steel, upstream mining, aluminium, organic chemicals, pulp, newsprint and other paper industries, accounts for two–thirds of the total industrial energy demand. Between 1990 and 2000, increased industrial activity resulted in a 16.3% increase in energy use. The increase was somewhat mitigated by improvements in energy efficiency without which, the government estimates, industrial energy use would have been 25% higher.

The OEE's general approach to industry is to implement more stringent minimum efficiency standards for some industrial equipment (electrical motors, lamps) and to encourage and make voluntary action easier, both industry-wide and at the company level, in order to improve energy efficiency in industrial processes through best practices and technology development.

The government of Canada works with industry in voluntary action to promote energy efficiency through two leading measures:

- The Canadian Industry Program for Energy Conservation (CIPEC), a sector-level programme that targets a 1% increase in energy efficiency per annum through monitoring and reporting of energy intensity, networking and energy efficiency information diffusion. The programme has 25 task forces and a network of more than 40 trade associations. Organisations that participated in CIPEC realised significant energy savings. The mean five-year increase in energy consumption for non-participants was 5.2%, whereas the increase registered by CIPEC participants was only 2.2% during the same period.

- The Industrial Energy Innovators Initiative is a company-level programme that addresses barriers to planning, implementing and tracking energy efficiency projects in industry. In 2003, around 500 companies representing 80% of energy use were included in the programme. In 2001-

2002, 24 new companies signed on to be Industrial Energy Innovators. Member companies are eligible to receive co-funded energy audits, energy management workshops customised to individual company needs, advanced access to technical information and special recognition and celebration.

In 2001, the government of Canada launched the EnerGuide[15] for industry programmes, to promote and encourage financially the manufacture, purchase and use of more energy-efficient industrial equipment. EnerGuide is a voluntary label describing yearly energy consumption rating and its position on a scale between the most and least comparable models.

## TRANSPORT

Without significant energy efficiency improvements, energy final consumption for transport is projected to grow significantly, at an average annual rate of 3.5% until 2020, to reach 75.1 Mtoe in 2020.

Between 1990 and 2000, despite a significant growth in activity, transportation energy use increased by just over 21.5%. Transport energy use represented 28% of TFC in 2001. Road transport accounts for more than 77% of total transportation energy use. Without improvements in energy efficiency, the federal government estimates that the increase in energy use would have reached 40%.

Nevertheless, Canada has one of the highest levels of activity in passenger transport among OECD countries (measured in passenger-kilometres per capita). Geography, high car ownership and low fuel prices compared with international averages[16] contribute to this situation, but not for all vehicles.

High shares of cars and domestic aviation contribute to the high energy use per capita in passenger transportation. Recent growth in energy demand for transport is led by the rising preference of Canadians for minivans and sport utility vehicles[17], and an increase in the amount of freight shipped by truck.

Improvements in engine efficiency or in other efficiency-increasing techniques are mostly offset by the increase in average horsepower or weight of new cars. As a result, the average consumption observed in new cars fell by only 1.25% between 1995 and 2000 (to reach 7.9 litres of gasoline per 100 km) and

15. EnerGuide is used for three voluntary measures – EnerGuide for Houses, EnerGuide for Vehicles and EnerGuide for Industry.
16. Gasoline prices are relatively low on an international scale in Canada, but they are higher than in the US.
17. Although this may sound similar to US consumption patterns, a notable difference in Canada is the fast growing number of small cars sales that caught up in 2002 with consumption records they had reached in the late 1980s, a trend that is not observed in the US. Yet on Canadian roads, 51% of new cars were more than 1 360 kg in 2000, against 77% in 1985, and on average the horsepower of new cars increased from 106 hp to 152 hp over the same period.

remained stable in the overall car stock (to 9.1 litres of gasoline per 100 km). At present, recent data published by the IEA show that in 1998, Canadians drove as much as in many other IEA countries (including much smaller ones), around 8 000 vehicle-km per capita, but would use vehicles with lower efficiency than many other IEA countries (with a fuel efficiency just below 12 litres per 100 km on average in 1998), eventually affecting Canada's fuel use per capita[18]. The federal government is attempting to increase efficiency in transport by developing vehicle efficiency targets, but its main instruments are voluntary agreements, information to consumers and financial support to the development of new technologies (fuel cells, see Chapter 11 on R&D). The success of regulatory efforts to develop efficiency targets is constrained by the need for, but the absence of, similar initiatives to those taken in the US since a large share of vehicles used in Canada are imported from the US or the design of cars produced in Canada is often guided by the larger US market.

Through its Motor Vehicle Fuel Efficiency Initiative launched in the mid-1990s with the signing of two memoranda of understanding with the automobile industry (in 1995 with the Motor Vehicle Manufacturers Association and in 1996 with the Association of International Automobile Manufacturers of Canada)[19], the government of Canada aims to achieve a voluntary improvement of 25% in fuel efficiency in new vehicles by 2010.

Under a voluntary agreement, manufacturers attach an EnerGuide on fuel consumption to their new cars to provide information to consumers. The percentage of new vehicles on car lots with EnerGuide labels increased from 64% in 1999 to 77% in 2001, and in dealership showrooms from 47% to 56% over the same period.

In the February 2003 budget, the government of Canada granted an excise tax exemption for biodiesel. The federal government estimates the amount of ethanol blended into motor gasoline in Canada per annum to have reached 240 million litres in 2001, or less than 0.6% of the total motor gasoline final consumption. The Canadian ethanol industry is relatively new but shows tremendous growth potential. The government push for ethanol extends from the federal government's Climate Change Plan for Canada (2002) and its recently launched "Ethanol Expansion Program" (2003). These initiatives allocate $100 million (60% available in the first year) to contribute to the funding required to build a number of ethanol plants beginning in early 2004. The Climate Change Plan targets 35% of gasoline supply being blended with ethanol by 2010. The Future Fuels Initiative includes the National Biomass Ethanol Program (NBEP). The Future Fuels Initiative provides contingent loan

18. See IEA, *30 years of Energy Use in IEA Countries*, Paris, 2004.
19. The Motor Vehicle Fuel Efficiency Initiative is based on the earlier Motor Vehicle Fuel Consumption Program (MVFCP) initiated in the late 1970s which encourages motor vehicle manufacturers to meet voluntary annual company average fuel consumption (CAFC) targets for new automobiles sold in Canada.

guarantees of up to $140 million to encourage investment in new ethanol production facilities, funds for analytical research such as new feedstocks and conversion technologies, and public awareness activities.

In 2002, the government of Canada began a Transit Pass Pilot Project which allows federal government employees to purchase bus passes at a discount through payroll deductions.

## RESIDENTIAL AND COMMERCIAL SECTORS

The residential and commercial/institutional sectors account for 17% and 13% respectively of secondary energy use. OEE calculates that residential and commercial/institutional energy consumption increased by 6.8% and 22.1% between 1990 and 2000 respectively. Without improvements in energy efficiency, OEE estimates that the increase in energy use would have been 15.1% and 25% higher in the residential and commercial/institutional sectors respectively.

The OEE takes the following approach to improving efficiency in these two sectors:

- Information, labelling (EnerGuide and Energy Star) and incentives to accelerate deployment of more energy-efficient equipment used in these sectors.
- Standards and regulations to gradually exclude from the market the least efficient equipment used in these sectors.
- Supporting the design and construction of more energy-efficient houses through voluntary standard development and training (R-2000 Homes) and labelling of new homes (EnerGuide for New Houses).
- Incentives to improve the energy performance of new buildings through incentives for more energy-efficient designs (Commercial Buildings Incentives Program).
- Performance-based incentives to improve the energy efficiency of existing housing (EnerGuide for Houses).
- Incentives to improve the energy performance of existing buildings (Energy Innovators Program).
- Support for building codes development.
- Consumer information.
- Partnerships with key associations to encourage investments in energy-efficient building retrofits to lower costs and reduce $CO_2$ emissions.

Though the stock of major appliances increased by 25% between 1990 and 2000, the energy used by these appliances decreased by 10%. This development was partly due to the effectiveness of the federal government's regulation and labelling programmes. In 2001, the government of Canada launched an initiative for the adoption and use of the internationally accepted Energy Star symbol. The symbol allows the consumer to easily identify the most energy-efficient products available on the basis of a set of criteria. The initiative also encourages the purchase of "best in class" energy-efficient products. Since the first Energy Efficiency Regulations were implemented in 1995 under the 1993 Energy Efficiency Act, labels and standards have been established for more than 30 products that consume 80% of the energy used in the residential sector and 50% in the commercial and institutional sector.

A number of programmes target residential and commercial buildings through different mechanisms. In 2003, the federal government launched an EnerGuide for Houses Retrofit Incentives Program for the residential sector to promote renovations in houses leading to increased energy efficiency. This programme is associated with control measures by independent energy auditing institutions to assess the eligibility of owners. For new houses, R-2000 is an industry-endorsed voluntary certification programme that features a technical performance standard for energy efficiency, indoor air quality and environmental responsiveness. The Model National Energy Code for new residential and commercial buildings was developed by the federal government in co-operation with other stakeholders. However, building codes are under the responsibility of provinces and only a few provinces are adopting the Model National Energy Code. Similarly, the diffusion of the R-2000 standard in provinces is limited.

Since its inception in 1998, the Commercial Building Incentive Program (CBIP) provided support to 165 projects. These projects were designed to achieve, on average, a 32% improvement in energy performance, more than what is required in the Model National Energy Code for Buildings.

The Energy Innovators Initiative (EII) provides financial incentives for the energy retrofit of existing institutional and commercial buildings. In 2001-2003, it financially supported 205 planning and retrofit projects that reduced their energy consumption by an average of 20%.

In 1995, the government of Canada committed to reducing its own $CO_2$ emissions by at least 20% from the 1990 level by 2005 and launched the Federal House in Order Initiative. This target was then upgraded to 31% in 2000 with the Action Plan 2000. This goal will be achieved primarily by making energy efficiency improvements in buildings, putting the "federal garage in order", switching to cleaner fuels and buying more renewable energy. Two leading programmes help achieve the goal: the Federal Building Initiative and the Federal Vehicle Initiative. Some provinces and municipalities replicate the initiative approach. In 2001, the federal government had achieved a 24.4% emissions reduction level.

Fostering energy efficiency is one of the key elements of the Canadian approach on the limitation of $CO_2$ emissions. The federal government projects the residential sector to be the only sector where $CO_2$ emissions will be lower in 2010 than in 1990. Equally important, policy measures taken to reduce emissions in this sector become increasingly effective, even after 2010, because of the slow stock turnover in buildings. In all other sectors, the balance is less positive, since activity increases and structural changes are expected to outweigh the energy intensity improvements triggered by the policy initiatives in spite of the new measures envisaged in the Climate Change Plan.

## CRITIQUE

Canada has made significant improvements in increasing both the visibility of its energy efficiency policies and the systematic efforts to seek efficiency improvements in all sectors. The government's efforts carried out with the help of its Office of Energy Efficiency should be praised. Most important, measures are in place to constrain the growth of Canada's energy intensity. Formulating and implementing climate change mitigation policies have offered a new impetus to energy efficiency improvements.

In 2000, the Office of the Auditor General (OAG) conducted an evaluation of the OEE's performance and concluded that NRCan had made satisfactory progress in energy efficiency programmes in accordance with the previous OAG recommendations in 1997. The follow-up report by the OAG also noted improvements in the evaluation of energy efficiency performance (both projections and achievements). This has also improved the quality of NRCan's Report to Parliament on energy efficiency and alternative energy initiatives implemented under the authority of the 1993 Energy Efficiency Act. The operation of the Office of Energy Efficiency has increased the transparency and accountability of Canada's energy efficiency programme. The National Energy Use Database and the report *Energy Efficiency Trends in Canada* provide a good analytical basis for understanding energy use and efficiency trends in Canada. Both the database and the work on energy efficiency trends are valuable for priority-setting and for monitoring sectoral policy initiatives in the end-use sectors. The government should carry on monitoring energy efficiency improvements and reductions in energy intensity of processes and products *per se*.

Comprehensive regulation and labelling of appliances and equipment are now in place in the residential and commercial sectors. Standards, codes and regulations cover a large share of household energy consumption and achieve – where they are mandatory in nature – a high penetration in the market. A widening and strengthening of the building codes in the provinces is gradually occurring, although the adoption of, for example, the Model National Energy Code for Houses and Buildings or the participation in the R-2000 Program varies widely in the provinces. For appliances, federal Canadian regulation is influenced by initiatives in the US. For the coming years, the challenge remains for the federal government to foster a widespread adoption of regulation and codes by the provinces, in order to achieve the expected limitation of $CO_2$ emissions. The task for the federal government will be to gain an accepted and proactive role in the tightening of standards, especially for appliances and equipment, taking into account standards in the provinces and the US.

In the industry sector, the philosophy of efficiency policies remains the same as portrayed in the last review, focusing largely on voluntary measures. This focus on voluntary measures, coupled with strong integration with the US economy, tends to support the conclusion that there is limited economic incentive to industry to further minimise energy consumption. The voluntary approach dates back to the 1970s and government-industry collaboration has reached a remarkably high coverage of the national industrial players. But the commitments under these agreements do not appear to be a significant step beyond autonomous energy intensity improvement and may not be sufficient to meet the present-day challenge of energy conservation and $CO_2$ emissions mitigation. The federal government should strive to encourage stronger commitments. The introduction of emissions trading between the Large Final Emitters could be a strong driving force in this direction, provided the carbon price that emerges from the new market offers a sufficiently strong signal.

In transportation, federal measures rely mostly on the potential to establish improved practices and behaviour, through labelling, training and other information measures. With Canadian markets closely intertwined with the US, the range for domestic manoeuvre is perhaps most limited in this sector and explains the focus of the current policy programmes. Nonetheless, it is one of the sectors with the highest expected increases in energy consumption and $CO_2$ emissions.

Although a part of the high level of energy intensity of the Canadian economy is explained by structural factors that are difficult to modify, such as an extreme climate or the availability of space, more progress is still possible. With its excellent record in measuring, reporting and monitoring energy efficiency, Canada has now a good capacity to set more ambitious and sectoral energy efficiency goals and to achieve them. However, if the sectoral programmes are heavily reliant on voluntary measures, without strong economic incentives for structural changes, the scope of further efficiency improvement can be rather limited. Measures such as differentiation of vehicle taxation according to fuel efficiency, or selected fiscal incentives, might be worth considering in this context. This category of measures and their consistent integration with the existing approach clearly have to involve federal and provincial government action.

The role of provincial governments is essential in promoting further energy efficiency because they have strong authority, in particular in the residential/commercial sectors. On the other hand, provincial end-use policies, including collaboration with federal programmes, vary significantly across provinces and territories. Generally, provincial governments focus on energy supply issues and, apart from energy efficiency regulation of products, they appear to use and promote end-use initiatives – including those developed by the federal government – only to a limited extent or in a selected fashion. Provincial measures should primarily seek to implement the federal programmes at their levels and develop their own whenever they judge it necessary to complement the federal drive to adapt to provincial conditions or to go beyond federal goals. More consultation with provincial governments on energy efficiency policies is required to work out a comprehensive strategy that will eventually benefit the whole Canadian economy.

## RECOMMENDATIONS

*The government of Canada should:*

- *Continue to assess the potential for energy efficiency improvements in all Canadian energy producing and consuming sectors.*
- *Consider developing a new set of sectoral efficiency goals associated with the introduction of market-based incentives to increase the uptake of efficient practices and enable structural change across sectors.*
- *Investigate and implement stronger measures to accelerate the shift towards more efficient motor vehicles.*
- *Enhance the consultation process between the levels of the federal government and provinces and territories in order to develop a comprehensive strategy for energy efficiency.*

## INDUSTRY STRUCTURE

In 1990, the government of Canada formally ceased to restrict foreign ownership in the upstream petroleum sector. The decision to remove foreign ownership restrictions in the petroleum industry reflected, in part, trade liberalisation between Canada and its partners under the free trade agreements. Under the Canada–United States Free Trade Agreement and NAFTA, Canada made the commitment to provide "national treatment" to firms owned by American and Mexican citizens. Deregulation has increased the flow of investment in Canada's petroleum industry, facilitating its development.

About half the oil industry has a majority of its capital being owned by non-Canadians, with a few multinational oil companies dominating both upstream and downstream operations. Canadian oil resources are now being developed and produced primarily by the 140 companies that are members of the Canadian Association of Petroleum Producers (CAPP). Many smaller explorers and producers are also active (over 600 in Alberta, for example); 380 of them are represented by the Smaller Explorers and Producers Association of Canada (SEPAC) which are generally Canadian-owned and controlled.

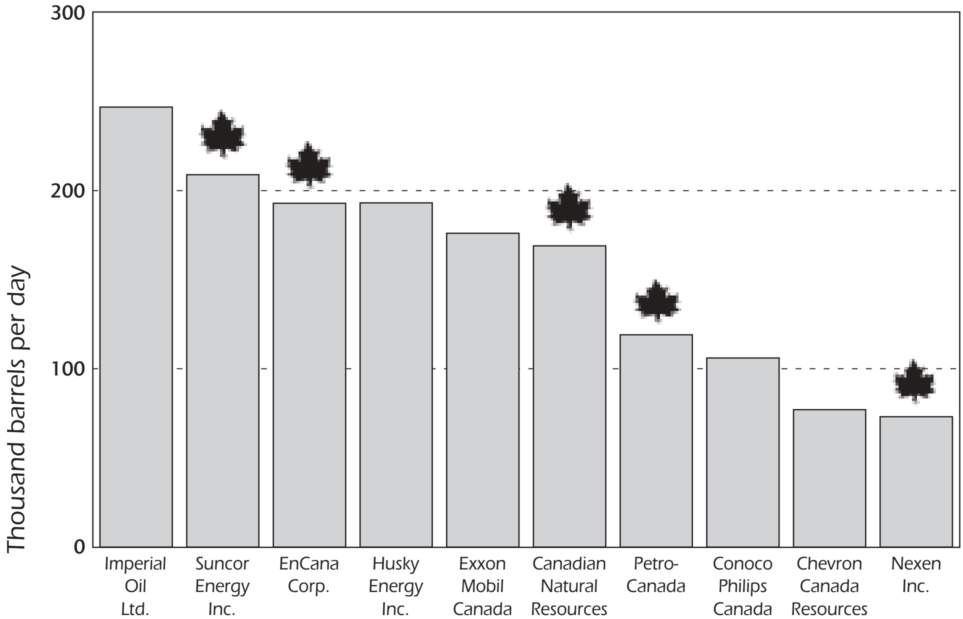
In 2002, the top 20 oil producers in Canada controlled 86% of domestic oil production. Five of the top ten oil producers have a majority of their capital owned by Canadians. Five Canadian firms (Encana, Canadian Natural Resources, Petro-Canada, Suncor and Nexen) accounted for 32% of all Canadian production.

The federal government retains 19% of the capital of Petro-Canada which was created as a government-owned company in 1975. The government interest has been privatised progressively since the early 1990s and further privatisation will be carried out when market conditions are judged suitable. The federal government and some provinces have also kept an interest in some smaller resource companies and energy projects.

In 2000, according to Statistics Canada, foreign businesses controlled 44% ($67 billion) of the assets and generated 56% ($40 billion) of the operating revenues in the oil and gas industry. These figures do not appear to be out of line with other capital-intensive, global sectors of Canada's economy. Foreign control of assets and operating revenue also exceeds 40% in manufacturing, and in non-depository credit intermediation and insurance industries.

Figure 15

**The Ten Largest Oil Producers in Canada, 2002**




Source: NRCan, *Oilweek Magazine.*

According to the Canadian Association of Petroleum Producers, the share of Canada's petroleum production held by foreign interests rose from 31% in August 1999 to 49% in May 2002. However, foreign control of Canadian petroleum production remains well below the peak level of 74% reached in 1977. Furthermore, foreign control of Canadian oil production did not grow in 2002 owing to a decline in the number of US-based mergers and acquisitions.

## MARKET TRENDS

### DOMESTIC PRODUCTION

Canada is the world's ninth-largest oil producer. In 2002, total production of crude oil and equivalent hydrocarbons reached around 2.37 million barrels per day (mbd). More than half the volume produced (1.46 mbd) was exported to markets in the US (mainly in the Midwest). Around 905 thousand barrels per day (kbd) were imported into eastern Canada (mainly in Québec and the Atlantic provinces) for refineries exporting products to the northeast US, resulting in net exports of 557 kbd, or 24% of production. Between 1999 and 2002, total domestic crude oil production grew at an annual average of 4%, largely sustained by the growth of crude oil production from oil sands which grew by 10% per annum during the same period.

Conventional light and medium, conventional heavy and offshore oil accounted for about 1.4 mbd. Oil sands crudes (bitumen blend, synthetic bitumen blend, upgraded oil sands light) accounted for the remainder. Canada's crude production requirements are becoming increasingly dependent on oil sands bitumen blends and synthetic crude. The federal government and the National Energy Board estimate that these sources could represent approximately 60% of the various crude products produced in Canada by 2010 (see Table 10) from a little above 45% in 2003. Canadian bitumen and synthetic crude are used domestically and are exported to the US. In terms of crude and product exports, Canada is the first-ranked supplier to the US market.

**Table 10**

**Oil Production Projections**

(kbd)

| | *2000* | *2005* | *2006* | *2007* | *2008* | *2009* | *2010* |
|---|---|---|---|---|---|---|---|
| Condensates | 177 | 171 | 171 | 170 | 167 | 162 | 170 |
| Mining / upgraded bitumen | 315 | 754 | 778 | 788 | 823 | 881 | 904 |
| In situ bitumen | 279 | 503 | 540 | 577 | 606 | 650 | 703 |
| Conventional light – WCSB | 662 | 556 | 533 | 513 | 496 | 480 | 464 |
| Conventional heavy-WCSB | 560 | 571 | 571 | 563 | 551 | 535 | 516 |
| Conventional east coast | 148 | 379 | 398 | 357 | 321 | 317 | 321 |
| **Total** | **2 141** | **2 934** | **2 991** | **2 968** | **2 964** | **3 025** | **3 078** |

WCSB = Western Canadian Sedimentary Basin.
Source: National Energy Board.

In 2002, according to the US Energy Information Administration, Canadian exports represented 18% of net US petroleum imports and 9% of US consumption. Canada's share of US supply is expected to increase with higher oil sands production.

The location of Canada's conventional oil and gas reserves is fairly well known and defined[20]. Although Canada's oil resources are geographically

20. This report uses terminology used in Canada, but not necessarily elsewhere. The term "conventional" highlights the difference between regular crude – that is, petroleum found in liquid form, flowing naturally or capable of being pumped without further processing or dilution – and either (1) crude that is located in less accessible locations (for example offshore continental shelves) or (2) "synthetic" crude that is produced by upgrading oil sands bitumen deposits. Upgrading is accomplished by either removing carbon (for example by coking) or adding hydrogen (for example hydro treating or hydro cracking). Synthetic crude has some special characteristics. It has virtually no impurities and bottoms content compared with regular crude that contains a full spectrum of molecules. Bitumen, in the Canadian context, is extra heavy crude (*i.e.* 12 API); it does not flow under normal conditions. Bitumen is either mined or produced *in situ* (steam-assisted gravity drainage or cyclic steam stimulation) from oil sands, also referred to as tar sands, and is blended to make it transportable, or coked or upgraded to produce "synthetic" crude. Bitumen is not kerogen, the hydrocarbon found in oil shale.

dispersed, most Canadian oil production is in western Canada, principally in Alberta. The largest population and industrial centres generating most petroleum demand, however, are in the eastern provinces of Ontario and Québec. For economic and logistical reasons, in particular large land transport distances, Québec and the Atlantic provinces depend on imported sources of oil. Ontario also has access to imported oil with the reversal of the pipeline between Sarnia (where much of Ontario's refining capacity is located) and Montreal.

Private companies undertake petroleum exploration and production under licences granted by federal and/or provincial government authorities.

Since 1997, the number of oil wells drilled in Canada regained growth. After a peak in 1997 at 8 543, it decreased to 2 761 wells in 1998 and reached 4 319 wells in 2002. Increased cash flow from high oil prices, improvements in royalty rate structures, higher demand from Canadian and US markets and the gradual settlement of native land claims issues have all contributed to the increase in drilling activity.

## Offshore

In recent years, east coast offshore and northern Canada has seen increased exploration and development activity. Provinces also regulate oil production in their jurisdiction. Provincial government licenses oil production in accordance with its constitutional responsibility for conservation and management of the resource. In the Atlantic offshore areas, joint federal-provincial management bodies, the Canada-Newfoundland Offshore Petroleum Board and the Canada-Nova Scotia Offshore Petroleum Board, license production. In onshore areas of northern Canada, the National Energy Board, under contract to the Yukon and territorial governments and the Federal Department of Indian Affairs, performs production licensing.

In Newfoundland and Labrador, offshore conventional crude oil reserves are concentrated in Hibernia, Terra Nova and the White Rose oil fields. Hibernia's production began in November 1997 and in 1998, the oil field completed its first full year of production. Hibernia has recoverable reserves estimated at 865 million barrels of oil with production of 180 kbd in 2002. A consortium of six companies, including an 8.5% share held by the government of Canada, is operating the field. Hibernia is located east of St. John's, Newfoundland. The Terra Nova oil field is the second largest oil field off Canada's east coast, with recoverable reserves of 405 million barrels of oil. Despite delays and cost overruns, the Terra Nova project began delivering 20 kbd in January 2002. It reached 95 kbd in March and ended 2002 with 115 kbd. A consortium of seven companies holds an interest in the Terra Nova offshore oil project. Commercial oil production from White Rose oil field is expected to begin in 2005. Recoverable reserves from the White Rose are estimated at 280 million barrels of oil. Offshore Newfoundland production is shipped to east coast refineries in both Canada and the US.

Oil resources offshore British Columbia have been estimated at around 10 billion barrels of oil, but oil resources in British Columbia have been barred from being exploited by a moratorium originally implemented in 1959, then lifted briefly in the late 1960s before being imposed again. Discussions have been on and off for several years to review the moratorium, in the light of economic development needs for the region, as well as technological improvements enabling the reduction of environmental risks associated with oil exploration and production. Currently, a federal review process is under way to inform a decision by the government of Canada on whether to lift the federal moratorium on oil and gas activities for the Queen Charlotte Basin area offshore British Columbia. There are three elements to the review: a science review, a public hearing process and First Nations engagement. The science review was completed in February 2004.

## Oil Sands

Oil sands generally refers to a mixture of bitumen, sand and clay. Bitumen is an extremely heavy crude oil. In its natural state, crude bitumen is so viscous that it cannot flow easily enough to be recovered by conventional drilling. It must either be mined or produced by *in situ* processes that generally involve heating the sands and the oil it contains to enable it to flow[21].

Canada's oil sands are spread across 77 000 sq. km of relatively remote northern Alberta landscape in the Western Canada Sedimentary Basin. They are located in four deposits – Peace River to the northwest, Athabasca and Wabasca to the northeast, and Cold Lake to the east. These deposits cover a minimum of 4.3 million hectares (ha), 729 thousand ha and 976 thousands ha, respectively. The oil sands contain an initial in-place volume of 1.6 to 2.5 trillion barrels of crude bitumen from which the oil is recovered. The Alberta Energy Utilities Board has estimated that, with anticipated technological improvements and estimated economic conditions, up to 319 billion barrels of bitumen could ultimately be recovered. The Alberta Energy Utilities Board estimated remaining established reserves recoverable at current costs and under existing economic conditions at 175 billion

21. Oil sands mining projects have three main functions: mining the bitumen resources using the truck and shovel methods, extracting the bitumen from sand and clay through a process of adding water and agitation, and upgrading the bitumen into a marketable commodity. Only about 20% of the oil sands layer is buried at depths of 80 metres or less, making surface mining economically feasible. *In situ* recovery is used for bitumen deposits buried beyond 80 metres for mining to be practical. Most *in situ* bitumen and heavy oil production come from deposits buried more than 400 metres below the surface of the earth. Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are *in situ* recovery methods, which include thermal injection through vertical or horizontal wells. Solvent and $CO_2$ injection are examples of other *in situ* recovery methods. Canada's largest *in situ* bitumen recovery project is at Cold Lake, where deposits are heated by steam injection to bring bitumen to the surface, then diluted with condensate for shipping by pipelines. Other technologies are emerging such as pulse technology and vapour recovery extraction (VAPEX).

barrels. This is far beyond conventional oil reserves of Canada (4.8 billion barrels), or even US (22 billion barrels of conventional oil), and puts Canada between the world's two largest reserves of Saudi Arabia (260 billion barrels) or Iraq (112 billion barrels).

Oil sands operations produce two products, bitumen and synthetic crude oil. Bitumen is a very dense, black, tar-like substance that must be upgraded to make it an acceptable feedstock for refineries. Bitumen can be upgraded on site into synthetic crude oil that has density and flow characteristics similar to conventional light crude oil, but with very low sulphur content. Bitumen that is not upgraded on site is blended with diluent, and shipped via pipeline to a refinery for feedstock.

Production of bitumen and synthetic crude oil from oil sands has grown dramatically, from 217 kbd in 1985 to 740 kbd in 2002. In 2002, 439 kbd of synthetic crude and 301 kbd of bitumen were produced. In 2002, 814 kbd (or 56%) of Canada's total oil exports to the United States were from conventional oil production, and 646 kbd from oil sands production (407 kbd of bitumen and 239 kbd of synthetic crude oil).

Continued technological innovation and know-how have substantially reduced capital and operating costs. The production unit cost decreased from US$ 30/barrel (bbl) in the early 1980s to US$ 8-12/bbl today. It is projected to further decline to the range of US$ 7-10/bbl by 2015, which would significantly improve the competitiveness of oil sands operations.

The production of oil sands has been dominated by two companies, namely Syncrude and Suncor, which produce light synthetic crude at a high fixed cost, but low variable cost. Syncrude and Suncor mostly use an open-pit mining process. In this process, resources are better assessed and, therefore, unlike conventional oil, their oil sands production rate is relatively fixed. Because of the scale of the mining operations, producers necessarily plan over an extended period and do not respond to short-term movements in oil prices. The current production trend is gradually moving to developing *in situ* operations. *In situ* production can involve relatively smaller amounts of capital upfront and their profitability can be secured with smaller outputs. *In situ* projects also have lower labour costs. The Albian Sands Project joined the ranks of Suncor and Syncrude by achieving fully integrated operations by April 2003. Also, Imperial's Cold Lake cyclic steam project has been in production since 1985 and has averaged production of 140 000 barrels per day (b/d).

The quantity of energy required to extract the bitumen *in situ* is more than double that for mining oil sands, and is raising concerns about the tensions that this will increasingly generate in the use of domestic energy sources, in particular natural gas, as oil sand production grows. Oil sand production is likely to carry on adding significant amounts of GHG emissions to Canada's emissions in the coming years. Industry, the federal and Alberta governments and academia are working on solutions to these problems through the Oil Sands Technology Roadmap.

Changes to the federal fiscal regime and provincial royalty regime have resulted in a favourable investment environment for petroleum exploration and development in Canada, both for conventional and non-conventional oil. In 1995, the government of Alberta announced the introduction of a new generic royalty regime for oil sands projects in the province, creating a lower royalty rate for the oil sands than conventional developments. Royalty is calculated on a revenue-less-cost calculation, which helps project cash flows in the early years. In the March 1996 budget, the federal government announced changes to its fiscal regime relating to oil sands. The Accelerated Capital Cost Allowances (ACCA), an investment incentive available to mines, was extended to eligible investments in *in situ* oil sands projects. In March 2003, the government of Canada announced that it was phasing out the existing 25% resource allowance and replacing it over a five-year time span with a full deduction, for income tax purposes, of the actual provincial Crown royalties and mining taxes paid. Furthermore, over this same five-year period (between 2003 and 2007), a reduction in the federal statutory corporate income tax rate on income earned from resource activities will gradually reduce taxes from 28% to 21%.

The petroleum industry in Canada responded favourably to these changes. As a result, $24 billion in new oil sands investment projects have been approved since 1996, of which $17 billion in investments are completed, and $7 billion in projects are still under construction. In addition, $62 billion in investments are under study, which brings total oil sands announced investment since 1996 to $86 billion.

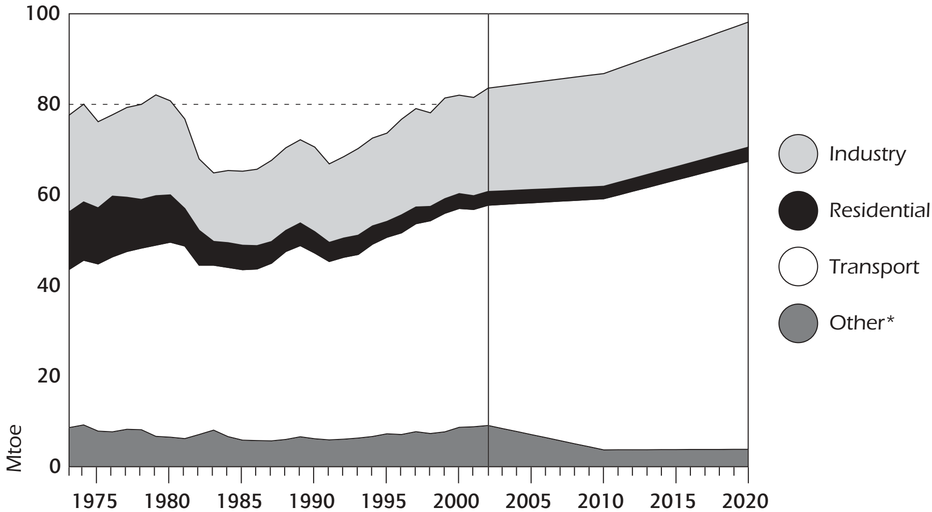
The production impact of the announced projects will be significant. However, estimates about the future growth of output vary significantly. The National Energy Board projects synthetic crude production to increase to 991 kbd and bitumen production to increase to 650 kbd by 2015, or a total of 1.6 mbd. If the total amount of $24 billion worth of investments in already committed projects comes on-stream with expected results, oil sands output could nearly double to 1.1 mbd in 2010. On top of that, there have been announcements for further investments with a different degree of certainty. In March 2002, the Regional Infrastructure Working Group (RIWG) of the Athabasca Oil Sands Developers (province of Alberta) assessed the amount of cumulated proposed investments in oil sands at approximately $84 billion to develop projects helping the total oil production to reach 3.8 mbd over the period 1995-2010.

## OIL DEMAND

In 2002, oil dominated the primary energy supply with 36% of the mix. Transport is the largest consuming sector and represented 65% of all secondary oil use in 2001, as compared to industrial oil use of about 20%.

Figure 16

**Final Consumption of Oil by Sector, 1973 to 2020**




* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

## EXTERNAL TRADE

Canada imports significant quantities of crude oil. A significant share comes from OECD countries (see Table 11). Canada also imports some oil products, mainly from the US. In spite of the availability of domestic oil and products, imports are explained by the large distances existing between the crude oil production sites, mainly located in the west in spite of the growing roles of east coast offshore oil production, and the consumption centres for products that are mainly Québec and Ontario. Canada's exports of crude oil and products are almost entirely going to the neighbouring US, in the east.

The anticipated increases in production would have a significant impact on future crude oil exports. In the NEB Base Case Scenario, crude oil exports would jump from 1.4 mbd to 1.9 mbd, an increase of about 39% by 2010. However, in the NEB Supply Push Scenario, crude oil exports would jump from 1.4 mbd to 2.1 mbd, an increase of about 50% by 2010.

Oil is shipped to domestic and US markets through three main pipeline systems:

- The Enbridge pipeline (formerly named Interprovincial), which delivers 1.7 mbd of crude oil from Edmonton in Alberta into the US Great Lakes region and the province of Ontario.

Table 11

## Imports of Crude Oil and Oil Products, 2002

(estimates)

| *Items* | *Main origin* | *Thousand metric tonnes* |
|---|---|---|
| Crude oil | Mexico | 1 109 |
| | Norway | 12 245 |
| | United Kingdom | 10 421 |
| | United States | 955 |
| | Venezuela | 3 154 |
| | Irak | 4 245 |
| | Saudi Arabia | 2 717 |
| | Algeria | 4 811 |
| | Nigeria | 883 |
| | **TOTAL** | **43 292** |
| Oil products | United States | 6 391 |
| | Venezuela | 733 |
| | **TOTAL** | **9 288** |

Source: IEA.

Table 12

## Exports of Crude Oil, Oil Sands Products and Oil Products, 2002

(estimates)

| *Items* | *Destination* | *Thousand metric tonnes* |
|---|---|---|
| Crude oil | United States | 56 844 |
| | **TOTAL** | **56 844** |
| Oil sands products | United States | 11 263 |
| | **TOTAL** | **11 263** |
| Oil products | United States | 19 622 |
| | **TOTAL** | **20 268** |

Source: IEA.

- The Express pipeline, which delivers crude oil from Alberta into Wyoming and onward via its Platte pipeline connection into Illinois.
- The Trans Mountain Pipe Line, which delivers oil mainly from Alberta west to Vancouver (British Columbia), the Puget Sound region of the US, and offshore through port facilities at Burnaby (British Columbia).

In 1997, the National Energy Board issued a Memorandum of Guidance to all companies under its jurisdiction setting out a new procedure to be followed by applicants for long-term oil export licences (25 years or more). These changes were meant to protect the public interest of Canadians by giving domestic refiners an opportunity to purchase domestic crude oil on terms no less favourable than those offered to foreign refiners. They also aimed to give producers more comfort with regard to long-term access to the export market. To obtain the licences, the procedures are similar to those that apply to natural gas and electricity exports. For long-term exports, the National Energy Board has a responsibility to ensure that exports are authorised only after due consideration has been given to meeting the long-term requirements of Canadians. However, the prime function of export licensing is to ensure a level playing field between Canadian and foreign consumers with regard to the consumption of Canada's oil resources. The licensing procedures for long-term exports are not intended primarily as a conservation mechanism. This is considered by the NEB to be a fair market test, and not a test of resource sufficiency.

There are no changes to the application requirements for exports of refined products from Canada. Permits for short-term exports of crude oil (one to two years) require only that a prospective exporter provides the name and address of the firm, a contact name and the volume of crude oil to be exported. This information is used essentially for monitoring and entails a minimum administrative burden.

## REFINING

Canadian refineries have undergone significant rationalisation in the past decade, with a total number of refineries decreasing from 58 in the 1970s to 18 in 2004. Most of the closures took place before 1995. In 2002, total crude oil refining capacity was 1.87 mbd and the rate of utilisation was 94%. Ontario and Québec have the largest capacity.

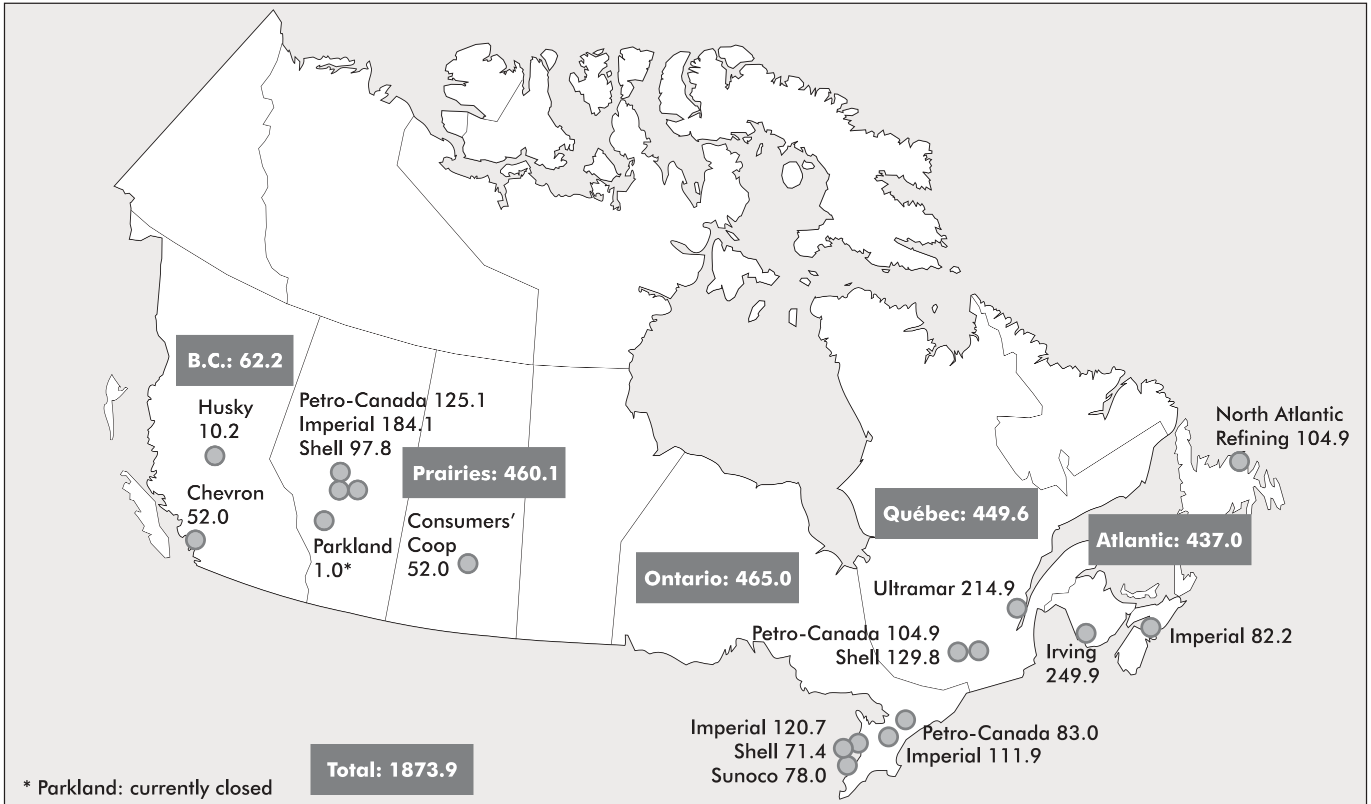
The federal government does little by way of economic regulation of the refining industry. However, the introduction of stringent environmental standards for vehicles and fuels will continue to present economic and technical challenges for Canadian oil refiners at least until 2010. Recent developments in this regard include:

- The requirement that, from July 1999, gasoline contains less than 1% benzene.
- The implementation, on a national basis, of the following standards for sulphur content in refined products:
  - Gasoline – average of 150 parts per million (ppm) for the period of July 2002 until December 2004; an annual average of 30 ppm with a maximum sulphur content per batch of 80 ppm, beginning January 2005.
  - Diesel fuel – proposed diesel fuel regulations will limit the sulphur content in on-road diesel to 15 ppm by 1 June 2006. Additional regulations concerning the sulphur content in off-road diesel fuel are also being developed.

Figure 17

## Refineries in Canada

(thousand barrels per day)




Source: NRCan.

Most future changes to the make-up of the Canadian refining industry are expected to be in response to changing fuel quality standards.

The map in figure 17 shows the location of the refineries in Canada. There are three main refining centres located in Edmonton (Alberta), Sarnia (Ontario) and Montreal (Québec). Manitoba and Prince Edward Island are the only provinces without a refinery and there are no refineries in the territories. Canada's oil economy is a dual market. Refineries in western Canada run domestically produced crude oil, those in Québec and Atlantic Canada run primarily imported crude oil, while refineries in Ontario run a mix of both imported and domestically produced crude oil. While Canada is a large and growing net oil exporter, crude oil imports satisfy approximately half of domestic refinery demand. Petroleum products move in both directions across the Canada/US border depending on market conditions. However, Atlantic Canada is a major exporter of refined products to the US east coast.

## EMERGENCY PREPAREDNESS

The Energy Supplies Emergency Act of 1978-79 as amended in 1990 is the legal instrument which deals with emergencies defined by the IEA's International Energy Program and/or national oil emergencies. In a declared emergency, it authorises the Energy Supplies Allocation Board, under its Mandatory Allocation Program, to prepare, develop and maintain in a state of readiness programmes to allocate crude oil and petroleum products, restrain demand for petroleum products, and ration gasoline and diesel fuel. The Emergency Act and the Emergency Preparedness Act of 1988 provide statutory powers to develop programmes for national emergencies that complement the Energy Supplies Emergency Act.

There is no legal federal authority for demand restraint prior to a declared emergency or prior to an emergency as defined by the IEA's International Energy Program. Such authority rests entirely with the provinces and territories. Some provinces already have legislative authority and other provinces are studying their legislation requirements. Those provinces that do not have demand restraint programmes would rely on energy efficiency programmes instead. At the federal level, media campaigns could be used to encourage voluntary consumption reductions and discourage hoarding.

As a net oil exporter, Canada does not have an IEA emergency reserve commitment and all oil stocks held in Canada are commercially owned. In a declared emergency, the federal government would decide the threshold level for activation of emergency measures in consultation with the oil industry.

Surge production would have a rather limited effect in a crisis. It typically could be used only under very severe emergency conditions. Moreover, provincial regulatory agencies could relax best production practices, but could not force oil companies actually to increase production.

## CRITIQUE

Production from Canada's oil industry is gradually shifting from the conventional producing areas in western Canada to increased production of bitumen and synthetic crude oil from oil sands, and to some extent to the east coast offshore. The federal and Alberta governments and other stakeholders are commended for their continuous efforts in developing the oil sands. Although the old oil fields display a rather high decline rate, higher levels of exploration and production drilling have managed to keep production levels growing. Future growth in oil output will also be supported by production of bitumen and by the output of conventional oil from the Hibernia field and other new offshore fields.

There seems to be sufficient pipeline capacity to carry the current oil production to the refineries and the markets, but there may be concerns in the near future unless sufficient capacity is added. The federal government will need to carefully monitor if regulations of pipeline returns offer sufficiently attractive terms for investors to come forward and gradually increase transportation capacity.

The federal government has continued to streamline licensing procedures for exploration and development of oil and gas in regions under its jurisdiction. Licensing procedures generally rely on the market to allocate Canadian supply where it is most advantageous. As a result, the regulatory framework places more emphasis on environmental and safety regulation rather than economic regulation. Project proponents are expected to consult broadly with stakeholders on such matters as environmental issues before applying for a certificate of public convenience and necessity so that new exploitation of oil resources have limited local environmental impacts. This is intended to bring forward issues and reduce the time taken for the formal application process. Oil resources offshore British Columbia are barred from being exploited by a moratorium that has been extended in time. The legitimacy of such impediments may benefit from being reviewed over time. The federal government will need to evaluate the extent to which it is possible to open areas now closed for exploration and production while ensuring environment protection. Impeding the exploitation of natural resources for environmental reasons may be an appropriate measure if environmental risks are considered too high. But technology and regulations evolve over time and reduce these environmental risks. Avoiding overburdening environmental regulations is essential to tap the economic potential of these resources.

The production of unconventional oil from oil sands from Canada offers significant potential which has just begun being tapped. Future growth in oil production will depend on the success of expansion plans envisaged in synthetic crude production from oil sands. Production from the oil sands currently seems to have a good economic margin. The economic potential for higher oil production from oil sands either by mining or *in situ* production also seems high. The federal government and the Alberta government will have to pursue efforts to facilitate developments in this industry.

However, the huge forecast expansion in oil sands output will have local environmental impacts and contribute significantly to growth in Canada's GHG emissions because of the high energy input (from gas) to produce synthetic crude. Companies involved will need to accelerate the efforts to rehabilitate the open mines after their exploitation and mitigate local environmental damage, and co-operate with the government to develop technologies that reduce emissions and preserve local natural resources such as water. The development of carbon sequestration technologies would benefit from an accrued allocation of resources by the federal government and commitments from the industry to develop the technologies.

The federal government has jurisdiction over international and inter-provincial issues. Offshore oil production development will benefit from an active federal leadership and support in harmonising regulatory inconsistencies that constitute an obstacle (because of duplication and overlap, generating long cycle times for approvals and increasing regulatory risk). The Atlantic Energy Roundtable has already promoted a consensus on such issues and its work would need to be supported to find and implement rapid solutions.

## RECOMMENDATIONS

*The government of Canada should:*

- *Evaluate the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *offshore British Columbia).*
- *Continue to facilitate the increase of oil sands production through fostering research and development on processing technology and environmental issues such as water treatment and $CO_2$ emissions reduction.*
- *Actively pursue the process to reduce the inconsistencies in regulations between the Atlantic provinces for offshore activity.*

# NATURAL GAS

## INDUSTRY STRUCTURE

The Canadian natural gas industry includes around 1 000 firms involved in exploration, production and processing. These firms are also often involved in oil production when both oil and gas are found together in the ground. The largest 100 companies account for more than 85% of production. The smaller producers tend to sell their output through marketers and aggregators, while many of the larger companies market their supplies directly.

A handful of firms are involved in gas storage, pipeline transmission and distribution to customers. Finally, several dozen firms are involved in marketing natural gas.

## GAS RESOURCES

Canada’s natural gas reserves are large and represent around 1% of the world total reserves (end 2002). Canada’s proved reserves have decreased over time, however, from 2 762 billion cubic metres at end 1990 to 1 702 bcm at end 2002 (IEA). At 2002 levels of production, Canada has about 77 years of natural gas resources.

These reserves are spread over a very large number of relatively small pools. The Western Canada Sedimentary Basin, centred in Alberta, accounts for around 70% of discovered resources and almost all production. Large undiscovered resources are estimated in the Canadian frontier areas. Estimates of the ultimate gas resource of the Western Canada Sedimentary Basin have tended to increase over time as a result of refined assessment methods and improved geological understanding of the basin.

## PRODUCTION

Canada’s production is the third-largest in the world (after Russia and the United States) with 182 bcm in 2002.

Production is principally in the Western Canada Sedimentary Basin centred in Alberta, but also covers parts of British Columbia, Saskatchewan, Northwest Territories, Yukon and Manitoba (and a minor production in Ontario), which together produced 97% of the total Canadian gas production in 2002. East coast off-shore production in Nova Scotia is growing in importance and brings gas to regions currently without gas supply, but represented only 3% of total

Table 13

## Canada's Gas Reserves and Resources

(bcm)

| (billion cubic metres year-end 2001) | Discovered marketable resources: Cumulative production | Remaining reserves | Resources | Total | Undiscovered resource | Ultimate resource potential |
|---|---|---|---|---|---|---|
| **WCSB conventional** | **3 557** | **1 527** | **0** | **5 083** | **2 804** | **7 887** |
| Alberta | 2 996 | 1 183 | 0 | 4 178 | 1 983 | 6 161 |
| British Columbia | 411 | 252 | 0 | 663 | 765 | 1 428 |
| Saskatchewan | 137 | 78 | 0 | 215 | 28 | 243 |
| Southern Territories | 13 | 14 | 0 | 27 | 28 | 55 |
| **WCSB unconventional** | **0** | **0** | **0** | **0** | **2 266** | **2 266** |
| **Other conventional** | **42** | **88** | **57** | **187** | **538** | **725** |
| Ontario | 33 | 12 | 0 | 45 | 28 | 73 |
| Scotian shelf | 9 | 76 | 57 | 142 | 510 | 652 |
| **Frontier** | **0** | **0** | **935** | **935** | **5 127** | **6 062** |
| Grand Banks/Labrador | 0 | 0 | 255 | 255 | 1 020 | 1 275 |
| Mackenzie/Beaufort | 0 | 0 | 255 | 255 | 1 558 | 1 813 |
| Arctic Islands | 0 | 0 | 397 | 397 | 878 | 1 275 |
| Other Yukon/NWT | 0 | 0 | 28 | 28 | 283 | 311 |
| Offshore west coast | 0 | 0 | 0 | 0 | 255 | 255 |
| Other frontier | 0 | 0 | 0 | 0 | 1 133 | 1 133 |
| **Total Canada** | **3 599** | **1 615** | **992** | **6 206** | **10 735** | **16 941** |

Note: *Cumulative production* is the total amount of hydrocarbons produced at a given date. *Remaining reserves* are initial reserves less cumulative production at a given time. *Resources* (discovered resources) are those estimated to be recoverable using known technology, but that have not yet been recognised as established reserves because of uncertain economic viability (*i.e.* there is no pipeline that reaches the resource). *Undiscovered resources* are those estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but which have not yet been shown to exist by drilling, testing or production. *Ultimate potential resources* is an estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology; it consists of cumulative production, remaining established reserves, discovered resources and undiscovered resources.

Source: NRCan, *Canada's Energy Future 2003*, Ottawa.

Canadian natural gas production in 2002. Exploration in frontier areas such as the Mackenzie Delta has not yet started but the government expects the projects to have their first gas flow by 2009. Project proponents filed a preliminary information package with regulators in June 2003. There is a moratorium on the exploitation of resources located offshore British Columbia.

Canadian coal-bed methane – also referred to as a form of unconventional natural gas – is slowly moving from an exploration phase into development mode. Coal-bed methane's potential is examined through 20 pilot projects in Alberta. A recent estimate quoted by NRCan in its *Canadian Natural Gas Review of 2002 and Outlook to 2015* (2003) shows Canadian coal-bed methane gas production in 2002, of around 100 wells, averaged a total between 0.4 and 0.7 mcm/day. Canada's coal-bed methane resources have been estimated to be between 100 and 500 thousand cubic feet.

However, despite ever-higher drilling activity, the growth in natural gas production has slowed down since the mid-1990s. Higher gas prices facilitated higher drilling activity in the early 2000s, but rapidly increasing supply in the short term is difficult because the sources of growth are located in areas requiring significant investments for development. Drilling activity is concentrated on shallow gas exploitation, with 6 804 gas drilling completions in 2002[22], and only 2 266 gas drilling completions in deeper formations[23].

Upstream development is carried out essentially under the responsibility of the provinces. The regulation of inter-provincial and international natural gas transmission pipelines is the responsibility of the NEB.

At present Canada does not import any LNG. Private developers are planning three LNG terminals on the east coast to supply growing gas demand of the eastern Canadian provinces and northeast US: Irving Oil–Canaport facility, Saint John, New Brunswick (5 bcm per annum); Access Northeast Energy, Point Tupper, Nova Scotia (7-10 bcm per annum); and Gaz Métro & Partners, Saint Lawrence River, Québec.

## *TRANSMISSION AND STORAGE*

As with oil, production is concentrated in the west and principal export and domestic markets are in the east, necessitating long transmission pipelines. There are eight major transmission pipelines, representing approximately 80 000 km of transport capacity carrying gas from the processing plants to the consuming regions and export points at the international border.

All natural gas transmission pipelines, both inter-provincial and intra-provincial, are owned and operated by private-sector companies, except the natural gas transmission system in Saskatchewan, TransGas Limited, which is a provincial Crown corporation under the authority of the SaskEnergy Act. The major natural gas pipeline transmission systems in Canada are: Duke Energy Gas Transmission (formerly Westcoast) located in British Columbia,

22. For Alberta, west of 4th meridian gas wells.
23. Including Alberta W5 and W6 meridian gas wells, plus most British Columbia gas wells.

TransCanada Pipelines "Alberta System" (formerly Nova Gas Transmission Ltd.) and TransCanada Pipelines "Canadian Mainline" east of Alberta. These systems carry natural gas both for domestic and export markets. In addition, there are several export-oriented pipelines such as TransCanada Pipelines "BC System" (formerly Alberta Natural Gas Company Ltd.), Foothills Pipeline Ltd., which spans British Columbia, Alberta and Saskatchewan, and the Maritimes and Northeast Pipeline, which transports gas to markets in Atlantic Canada and the US northeast. Canada's natural gas transmission pipeline network interconnects with the US pipeline system at 8 major export points[24] (among 16 interconnections) along the Canada-US border.

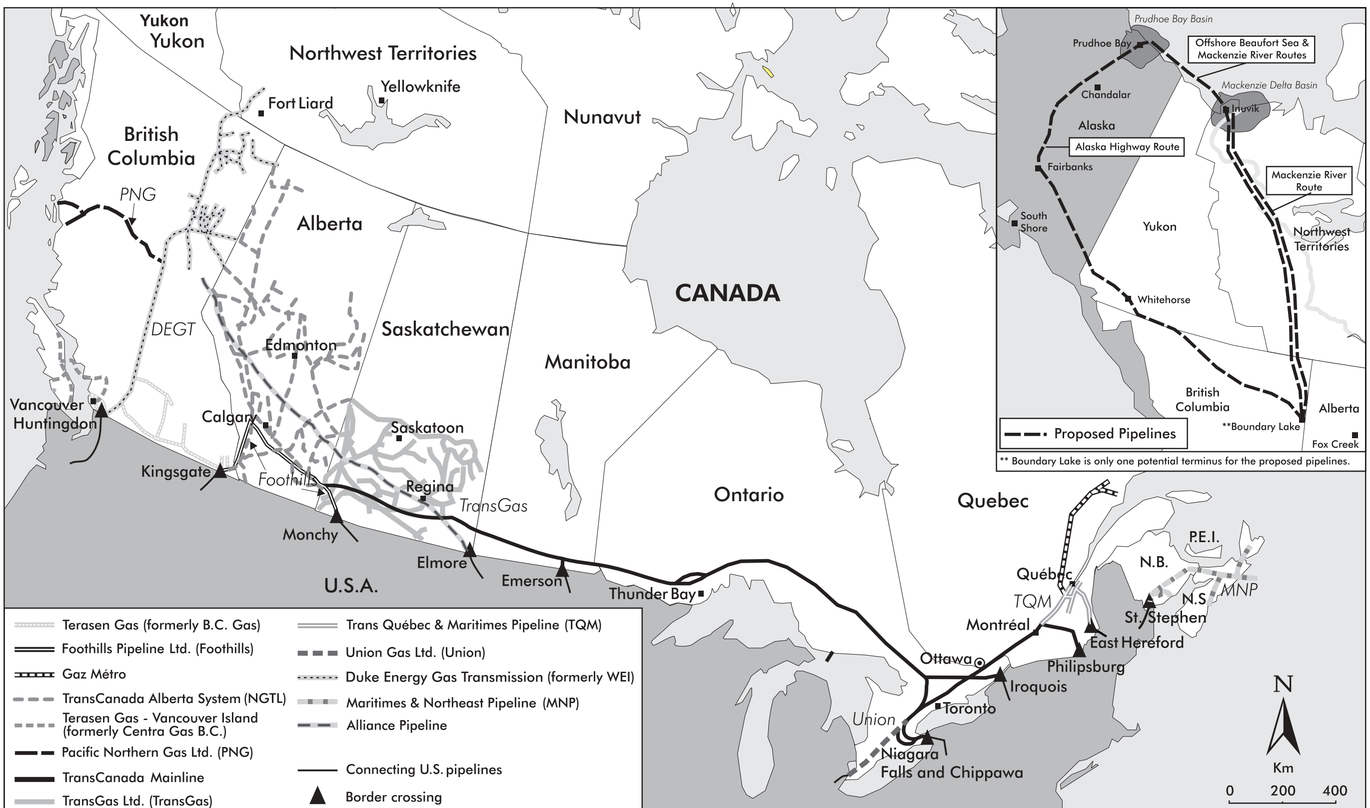
Canadian pipeline capacity is expanding as needed. Capacity of existing systems (*e.g.* TransCanada Pipelines) is augmented through applications to the National Energy Board. Gas supply growth, combined with strong demand in the US Midwest, California and northeast US, drove major pipeline construction to these regions at the end of the 1990s. The Northern Border Pipelines, reaching to Chicago, came on stream in 1998 and the Maritimes and Northeast Pipeline from Sable Island to New England in January 2000. The Alliance Pipeline project reaching Chicago was completed in December 2000. Several pipeline projects were suspended in 2002 following a decrease in natural gas prices. As of 2002, the physical export capacity reached 127 bcm. Pipeline capacity utilisation in Canada is generally high. Existing export capacity was used at close to 80% load factor in 2002. Right now, export capacity cannot be filled owing to a lack of gas supply. Because of various constraints, capacity is seldom used at 100% load factors. In recent years, the best fill rate for total export capacity was about 95%.

Development of the transmission network is left to the market. The National Energy Board prepares a comprehensive review of Canadian energy markets every two to four years (*Canadian Energy Future Scenarios for Supply and Demand to 2025*, last published in July 2003), and NRCan Gas Division prepares an annual review of North American gas markets. These publications provide information to the market on pipeline capacity, other market fundamentals and forecasts.

Vulnerability to supply disruption arising from long transmission pipelines is mitigated by duplicated lines and substantial upstream storage capacity in western Canada and downstream storage in eastern Canada. Storage also acts to mitigate production disruptions and seasonality of demand. Total storage capacity was 17.2 bcm in 2000, or 19% of gas consumption. Downstream storage is slightly higher than upstream storage, but upstream storage is being expanded in the producing regions.

24. Hungtinton and Kingsgate (British Columbia); Monchy (Saskatchewan); Elmore (Saskatchewan); Emerson, Niagara Falls (Ontario); Iroquois and Hereford (Québec); Saint Stephen (Nova Scotia).

## Figure 18
## Gas Transmission System




Source: *Natural Gas Information 2003*, IEA/OECD Paris, 2003.

The role of storage in Canada is essential to meet peak demand and hedging. Since deregulation in 1985, excess deliverability has decreased. Many producers and marketers have increased the proportion of their total gas supply that is sold on a short-term or spot basis. This enables them not only to backstop their long-term commitments, but also to take advantage of any short-term spikes. For many years, local distribution companies have used downstream storage facilities located near their markets as an efficient tool to manage their gas supply portfolios and their customers' gas peak demand during the heating season. Downstream storage is increasingly used not only by local distributors but by end-users, marketers and pipeline companies as a way of increasing the reliability of gas supplies.

## DISTRIBUTION

Distribution is carried out by 16 local utilities that have a regulated monopoly over the physical distribution of gas. The largest eight utilities account for about 95% of total local distribution company sales. The largest, Enbridge Gas Distribution, supplies about 25% of customers, and the smallest has less than 10 000 customers. With two exceptions, local distribution companies (LDCs) are privately owned. SaskEnergy is a Crown corporation in Saskatchewan, and in 1999 Manitoba Hydro (a Crown corporation) bought the private gas distribution company, Centra Gas Manitoba. Within Alberta, municipally-owned utilities and regional gas co-operatives account for nearly 10% of the distribution.

Third-party access (TPA) is allowed to the distribution grids and some large industrial customers and power generators can buy gas directly from producers. Some smaller customers in the residential and commercial sectors can also buy gas directly from producers through aggregators, brokers and other middlemen. There are about 4.8 million customers (4.2 million residential customers, 0.47 million commercial customers and 18 000 industrial customers).

## RETAIL COMPETITION

Retail gas competition has been developing in a number of provinces for some years, including Alberta and Ontario. The development was encouraged by falling gas prices and has been slowed by higher prices and by experience with price spikes.

Ontario was one of the first jurisdictions in North America to allow residential and other small volume customers to buy natural gas competitively. Ontario began opening up its gas market in the mid-1980s. Competition in the Ontario market led to a significant drop in the commodity price of gas. Well over a dozen brokers became active in the Ontario market and the distribution utilities estimate that around 40% of residential customers in Ontario buy their gas from an entity other than their distribution utility. The cost of utilities' gas fell owing to competition as well as to the price negotiated by aggregators. In Ontario, however, because title was held by the local distribution company, smaller customers could only enter into buy/sell arrangements with aggregators. While the rebates offered by the aggregators had the same effect as price reductions for consumers and put effective downward price pressure on producers, supply obligations on aggregators were limited and gas utilities were the suppliers of last resort providing customers with supply protection. The legislative impediments that tied title to the utility made the market less effective and competitive and some consumers complained that they did not receive their negotiated rebates. By allowing title to gas to be held by the supplier, legislation passed in 1998 has permitted the re-emergence of competition. Clarification of the role of distribution utilities as supplier of last resort and setting out the financial obligation for providing supply remains contentious.

Since 1996, Alberta has allowed residential and other small volume customers to buy gas competitively. Around 5% of residential customers in Alberta buy their gas from an entity other than their distribution utility. In 2003, Alberta aligned its legislation and regulations governing retail gas and electricity markets.

## DEMAND

At 29% of TPES in 2002, gas penetration is high in Canada compared with other IEA countries (22% on average). Canadian demand totalled 81 bcm in 2002, decreasing from the peak of 90 bcm attained in 2000. The industrial sector represents a third of the gas consumed (25 bcm) and the most price-sensitive part of consumption since it shrunk from almost 29 bcm in 1999 after the price hike of 2000-1 (see section on Gas Prices below). The residential sector consumed 16 bcm and commercial and public sectors absorbed another 13 bcm. Electricity generation consumed 9.9 bcm in 2001, up from 2.7 bcm in 1990 and 7.6 bcm in 1999. After electricity production, the second-fastest growing natural gas-consuming segment is oil sands extraction which consumed almost 15 bcm in 2001, from 9.6 bcm in 1990 and 14 bcm in 1999. Although the oil sand industry is considering the possibility of substitutes to natural gas, the current oil sand process requires 11.2 $m^3$ of natural gas to produce one barrel of oil in mined oil sands, and 28 $m^3$ for *in situ* oil sands.

Electricity restructuring will have a continuing influence on demand for gas. Gas use is expected to increase tenfold in central Canada between now and 2020. Growth in gas demand will be driven by increasing the use of combined-cycle gas generation technology, which will steadily gain market share from other forms of generation. By 2010, gas combined-cycle generation in Canada is forecast to be nearly as important a source of power as coal steam-cycle generation is at present. Future consumption of gas will, however, depend on the future role of nuclear and coal.

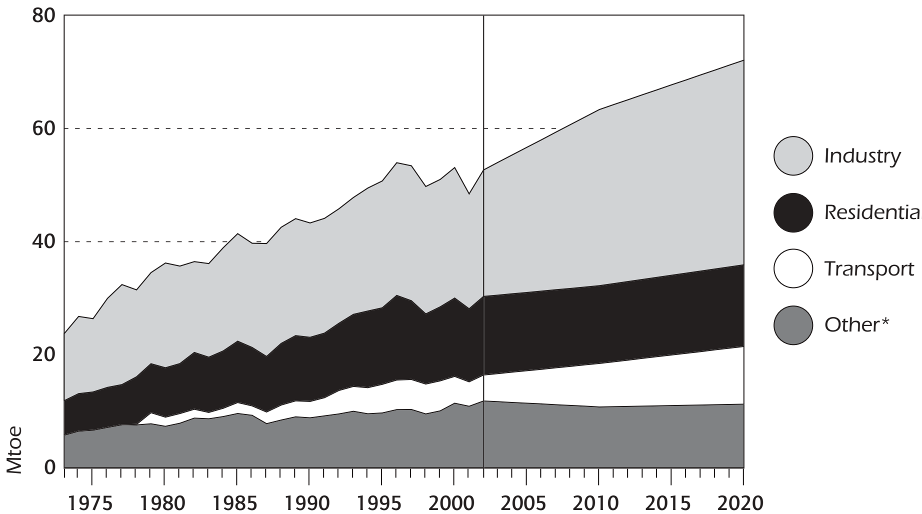
Growth in gas demand is expected to be higher in Canada (2.3% per year) than in the US (1.6% per year) to 2020, but the market will grow as a single North

American market. The integration of the Canadian and US markets, under the influence of electricity deregulation and rising gas demand, is expected to generate a doubling of gas flows between western Canada and the US Midwest to over 200 mcm/d by 2015. Forecast western Canada flows to domestic and export markets in eastern Canada indicate the need for 42 mcm/d of additional corridor capacity by 2020. An additional 14 mcm/d of capacity would be required to bring east coast offshore gas to Atlantic Canada and the US Northeast under Canadian Energy Research Institute scenarios.

Canada's net gas exports represent more than half of its production. In 2002, Canada exported 106 bcm, entirely to the US. Canadian gas represented 94% of US gas imports in 2002 and 17% of the total US gas supply. The prospect for sustained growth in domestic gas demand for the production of oil sands and other consumption segments, combined with slowing growth in production, is likely to translate in falling natural gas exports in the future and an upward pressure on natural gas prices.

**Figure 19**

**Final Consumption of Natural Gas by Sector, 1973 to 2020**




* includes commercial, public service and agricultural sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

Seasonality of gas demand is high, mainly because of weather patterns. The consumption profile of each market sector is important, as it defines the type of contracting practices and risk management the sector will pursue. The ratio between total gas sales in the peak and the lowest month of the year was 2.1 to 1 in 2000.

## REGULATION

The division of responsibilities for gas regulation in Canada is shown in Table 14.

Table 14

**Natural Gas Regulation in Canada**

| *Provincial* | *Federal* |
|---|---|
| • Production | • Inter-provincial transmission |
| • Processing | • Exports and imports |
| • Intra-provincial transmission | |
| • Distribution | |
| • Marketing | |

A federal agency, the NEB, is required by the NEB Act to ensure that export licences are given only as long as natural gas exports are surplus to reasonably foreseeable Canadian requirements. In July 1987, the NEB adopted the procedure known as Market-based Procedure to make this assessment. The basic premise of the procedure is that the market will work to satisfy Canadian requirements for natural gas at fair market prices. For this premise to be fulfilled, markets must be competitive, there should be no abuse of market power and all buyers should have access to gas on similar terms and conditions. These conditions were considered to be fulfilled by the Agreement on Natural Gas Prices and Markets signed in October 1985 between the governments of Canada and the three gas-producing provinces of British Columbia, Alberta and Saskatchewan. The agreement allowed gas buyers to directly contract for supplies with producers, marketers and other agents at freely negotiated prices.

Inter-provincial natural gas transmission pipelines are regulated by the NEB, which ensures that open, non-discriminatory access is provided to all shippers on inter-provincial gas pipelines. Inter-provincial transportation rates, conditions of access and terms of service are regulated by the National Energy Board. "Settlement agreements" on rates are often negotiated by large groups of shippers directly with the pipeline company. These agreements are then forwarded to the board, which may adopt the recommendation in its rates decision. However, the board sets transportation rates which are publicly known and are the same for all customers. The board has powers to hold public hearings, if considered necessary.

Local distribution companies are regulated at the provincial level by public utility commissions. The commissions regulate the rates charged by the companies for services, and authorise construction of transmission and distribution lines, including approving and recommending the granting of a franchise area.

Public utility commissions ensure that rates are fair, that gas supplies are secure and that environmental issues are addressed. Most commissions impose minimal supply conditions on agents, brokers and marketers. In contrast, LDCs are usually required to hold natural gas supplies to cover all their direct sales for a number of years. However, if consumers choose to purchase gas from other than local distribution companies, security of supply is less certain. Agents, brokers and marketers are not required to meet any minimum supply requirement to serve residential consumers. In the case of a supply disruption, the commission relies on other agents, brokers and marketers, or on the local distribution company, to use all reasonable means to mitigate any gas disruption. In practice, physical supply is unlikely to be disrupted, but the price at which supply is provided may rise.

## GAS PRICES

Gas prices in the industry and household sectors are very low compared to international levels.

Gas prices were deregulated in 1985. Since then, a general decreasing trend was initially observed. For example, average gas prices at the Alberta provincial border decreased by 53% in real terms between 1985 and 1997 (and 36% in nominal terms, from $2.8/GJ to $1.8/GJ). In response to lower gas prices, demand grew rapidly in the 1990s, until the price spikes of 2001. Canadian natural gas commodity prices have risen from an average of $2.77/GJ in 1999 to an average of $5.91/GJ in 2001. Prices were particularly high during the 2000-1 winter, reaching a high of $13.78/GJ in January 2001. Extremely high gas prices in the winter of 2000-1 were the result of numerous events occurring simultaneously: low storage inventories, very cold weather and higher demand – especially for power generation. The 2001 price hike led to significant gas demand destruction and a price adjustment in 2002. North American gas demand fell by nearly 5% in 2001 as a result of high prices and a weakening economy. Most of the demand loss occurred in the industrial sector, particularly in the ammonia and methanol industries, where companies temporarily, or in some cases permanently, shut down plants to move to areas providing low-cost gas supplies.

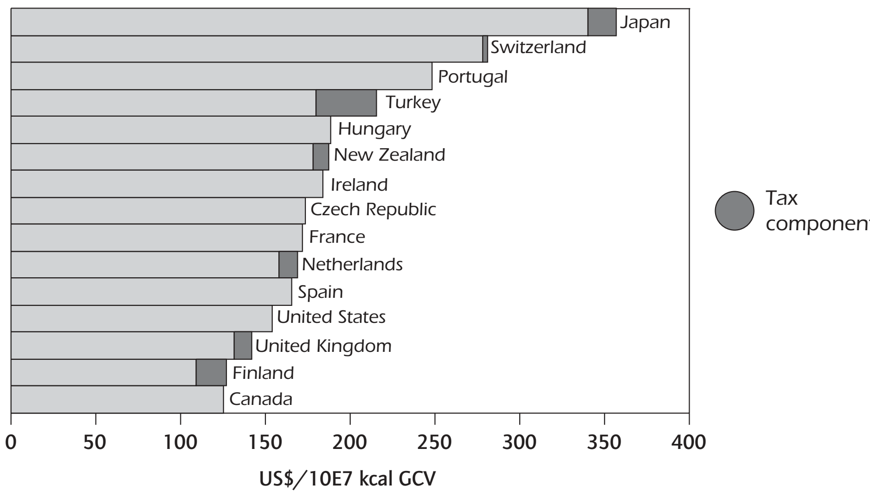
In 2001, to compensate consumers for high energy prices, the government of Canada introduced a $1.3 billion heating rebate programme. The programme offered a rebate of $125 per individual and $250 per household. The heating rebate assisted Canadians who were most vulnerable – low-income Canadians, including seniors and rural Canadians.

Prices have moderated since then, averaging $3.83/GJ for Alberta gas in 2002. Although prices have fallen, they have not fallen back to the levels seen in 1998 and before, mainly because of the growing interaction between US and Canadian gas supply and demand conditions, leading to an increased connection between Canadian and US natural gas prices.

Figure 20

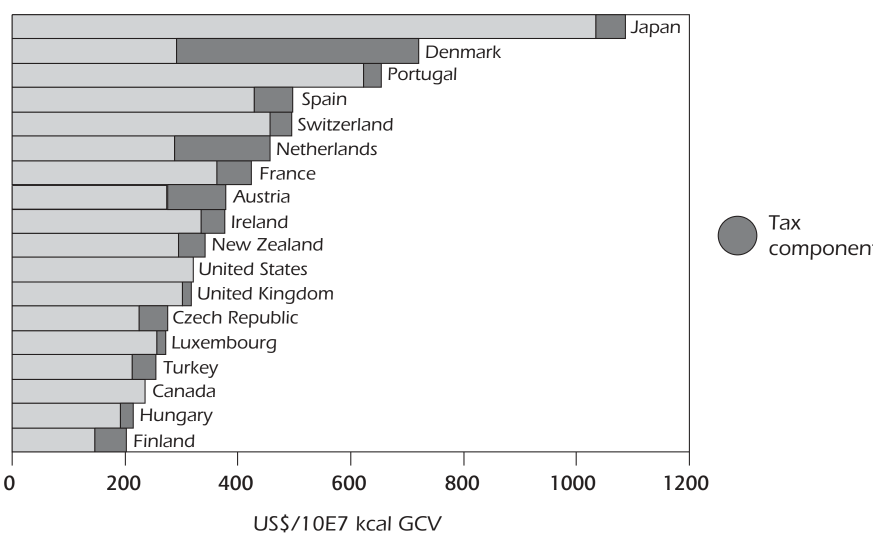
## Gas Prices in IEA Countries, 2002

### Industry Sector




Note: Tax information not available for Canada and the United States. Data not available for Australia, Austria, Belgium, Denmark, Germany, Greece, Italy, Korea, Luxembourg, Norway and Sweden.

### Household Sector

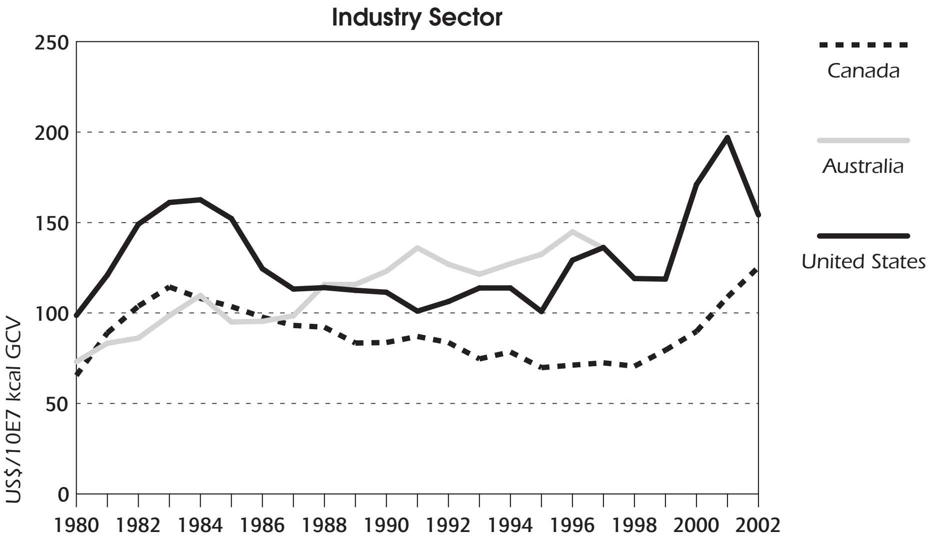


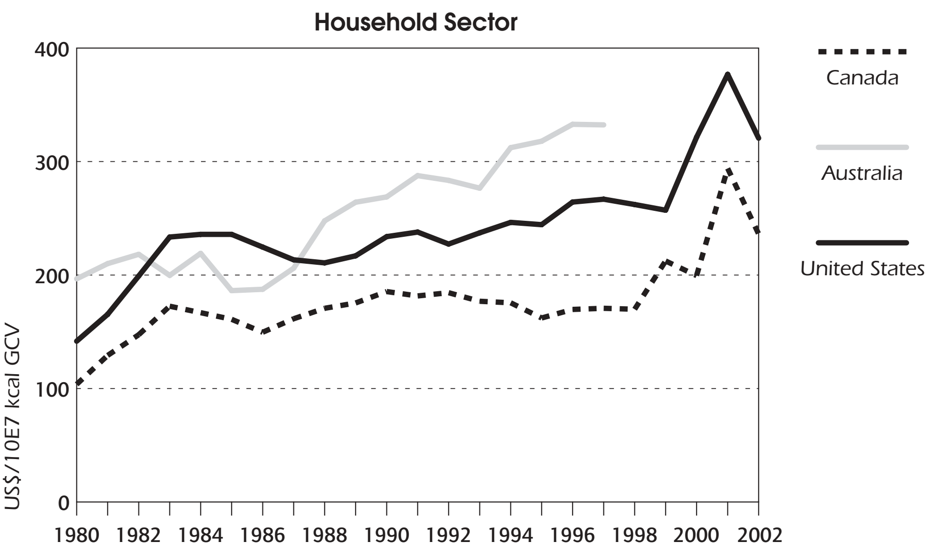

Note: Tax information not available for Canada and the United States. Data not available for Australia, Belgium, Germany, Greece, Italy, Korea, Norway and Sweden.

Source: E*nergy Prices and Taxes*, IEA/OECD Paris, 2003.

Figure 21

## Gas Prices in Canada and in Other Selected IEA Countries, 1980 to 2002




Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2003.

In late 2002 and early 2003, spot prices grew again, reaching a peak of \$8.45/GJ in March 2003 and are expected to average \$4.8/GJ in 2004. This is purely a result of market fundamentals, combining a growing demand and supply constrained for multiple reasons (lower find rates in exploration, environmental constraints to access domestic resources) and affects the whole of North America.

## CRITIQUE

The reserve situation for natural gas is satisfactory and relatively stable given current demand conditions. The drilling level is high. The resulting increase in production, while disappointing, is sufficient to meet domestic demand and significant levels of exports to the US. However, the North American natural gas market is becoming tighter, and may ultimately need to turn to external gas supplies in the form of LNG.

Large and yet unexploited resources exist, but efforts may be required in the future to stimulate production. There is currently a possible bias towards drilling for shallow gas that could be explained by a combination of factors related to the structure of the industry, geology and taxation regime. The bulk of drilling activity is pursued by numerous small companies in mature areas (such as the Western Canada Sedimentary Basin in Alberta) at limited risks and with low volume prospects, and the rest is made by larger companies in frontier areas where development is riskier, requiring more investment and lead time. This bias is reinforced by a favourable tax regime making it advantageous for small companies having successfully drilled wells to sell them to oil and gas income trusts[25]. While the exploitation of these wells by income trusts does not seem problematic, the reinvestment of profits by drilling companies in exploration activities could be limited.

Resources of coal bed methane (unconventional natural gas) have begun to be explored. Although coal bed methane's exploitation is taxed similarly to natural gas, there are different technical conditions of exploitation. Some natural constraints limit the productivity of coal bed methane exploitation. For example, in some cases there are water issues associated with coal bed methane exploitation that need to be managed and impact coal bed methane's production cost. It may, therefore, be appropriate for the government to consider levelling the playing field between conventional and unconventional gas exploitation to facilitate coal bed methane development.

25. An income trust is an investment syndicate that pools its money to buy a cash flow generating asset with the cash flow after expenses are distributed back to the unit holders. The trust does not engage in exploration, development, construction or manufacturing. It focuses on ownership and management with a view to generating income. The yield on income earned through royalty trusts is enhanced because the income earned is subject to only one level of taxation at the ultimate investor level (rather than being taxed at both the corporate and the investor levels).

Some promising areas in terms of resources remain closed to production for environmental reasons (such as offshore British Columbia). As technology evolves and environmental regulatory standards become more stringent, the risk of environmental damage decreases, thus enabling production in certain conditions. Efforts have been ongoing to assess the present situation and review the British Columbia moratorium (see Chapter 6 on Oil). The federal government, along with the province and, wherever necessary, representatives of First Nations, need to pursue efforts to review whether the interests of environment and production can both be safeguarded.

The Canadian gas sector is driven by competition upstream and is also strongly influenced by the US market, with large volumes of Canadian gas exported to the US. Well-developed infrastructures within Canada and between Canada and the US create an integrated North American market place for natural gas. Competition is well advanced. The regulatory environment in Canada has been stable, thereby creating trust by investors. Canadian pipeline companies are currently in a strong financial condition, and are able to raise capital to maintain and expand pipelines in Canada. In fact, Canadian pipeline companies are currently buying US ones. However, within the regulated pipeline sector, different rates of return and risk between Canada and the US affect competition for investment between Canada and the US. Regulators are aware of these possible discrepancies that could deter investments. In addition, to set up the long pipelines needed to transport gas from frontier areas to the markets requires numerous authorisations as these projects overlap jurisdiction, which can further deter investors. Where jurisdictions overlap, the NEB is working with a number of regulatory agencies to ensure that environmental assessment and regulatory issues are dealt with in a co-ordinated manner. Co-ordinated efforts have been focused on eliminating duplication while maintaining or enhancing meaningful public engagement. One of the NEB's key corporate strategies is to partner with other regulatory agencies wherever possible in order to improve regulatory processes and provide industry with a single location for all its administratives approvals. These efforts need to be pursued.

One last issue is the negative impacts of price volatility to natural gas household consumers. There is a direct link between retail prices and wholesale prices for households which makes them subject to price volatility. Natural gas commodity prices are negotiated in open, large wholesale markets between sellers and buyers of natural gas. Local distribution companies (LDCs) are large buyers of natural gas. Gas commodity price variations are directly passed through to household customers by LDCs. For Canadian residential gas consumers, an increase in natural gas commodity prices will generally result in an increase in consumer prices or "burner-tip" prices. LDCs may use storage and/or financial hedging to moderate the prices they pay for gas which they pass through to households. LDCs may also have equal monthly billing schemes for customers. However, even with such measures, prices vary considerably, and this often leads to complaints by consumers who generally dislike price volatility.

The commodity price charged by an LDC is scrutinised by the provincial energy regulatory authority. Currently, provincial policies generally discourage LDCs from extensive long-term gas purchasing or price hedging using financial instruments. Of the 8 provinces consuming gas, only British Columbia and Québec appear to allow significant hedging or long-term contracting directly by their LDCs. In most provinces, residential and commercial customers have the option of purchasing gas directly from marketers under 1 to 5-year fixed price contracts. However, this option often involves paying a considerable premium over current monthly prices in exchange for the price stabilisation feature. This is entirely regulated by provinces. Distribution companies tend to offer only a tariff which is passing through the wholesale commodity price to which is added the regulated price of distribution. Some earlier attempts were made by some municipal local distribution companies to offer more stable prices with a corresponding backup contract with some suppliers. These attempts largely failed because, in an environment of falling wholesale prices, the regulator did not approve passing the costs of the backup contract to consumers. In a fully liberalised market, consumers need to understand the risks involved in purchasing gas. At the same time, they should be offered protection from price volatility. In this context, the current policies of most provinces as described above may be narrowing this path. If provincial authorities do not deliberately opt for the direct exposure of households to price volatilities, some option against price volatility could be explored. Though this issue is a matter for the provinces, the federal government could play a role in encouraging a Canada-wide approach to this issue.

## RECOMMENDATIONS

*The government of Canada should:*

- *Consider reviewing the tax regime to ensure the level playing field between conventional and unconventional gas to facilitate the exploitation of coal-bed methane.*

- *Continue reviewing the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *British Columbia).*

- *Investigate whether it is possible to streamline the pipeline approval process so that all the stakeholders are taken into consideration in a more efficient way. Promote the concept of a one-stop shop for regulatory approvals.*

- *Explore, in co-operation with the provincial regulatory authorities, the possibility of offering household customers an option to automatically be hedged against price volatility.*

## RESERVES

Coal resources in western Canada extend from lignite deposits in Saskatchewan, to sub-bituminous and bituminous grades that underlie about three-quarters of the province of Alberta, and continue into northeast and southeast British Columbia. The rank of western Canadian coal decreases from west to east. The mountain region is principally medium- to low-volatile bituminous coal. In the foothills and extending into the southwest and northwest plains, the rank decreases to high-volatile bituminous coal, while in the remainder of the plains the grade decreases to lignite to the east.

Table 15

**Western Canada's Coal Reserves**

(Mt)

| *Region* | *Measured reserves* |
|---|---|
| Mountains | 2 860 |
| Foothills | 730 |
| Plains | 9 270 |

Source: IEA Coal Research, *Major Coalfields of the World*, London, 2002.

## PRODUCTION

Although production fluctuates from one year to the other, Canadian coal production is relatively stable since the mid-1980s, and is projected to remain so in the next two decades.

Table 16

**Canada's Hard Coal Production**

(Mt)

| | *1973* | *1980* | *1985* | *1990* | *1995* | *2000* | *2002e* |
|---|---|---|---|---|---|---|---|
| Production | 12.3 | 20.2 | 34.3 | 37.7 | 38.6 | 33.8 | 29.7 |
| Percentage of world production | 0.5 | 0.7 | 1.1 | 1.1 | 1.0 | 0.9 | 0.8 |

e: estimates.

Source: IEA.

Table 17

**Canada's Brown Coal* Production**

(Mt)

| | 1973 | 1980 | 1985 | 1990 | 1995 | 2000 | 2002e |
|---|---|---|---|---|---|---|---|
| Production | 8.1 | 16.5 | 26.5 | 30.7 | 36.3 | 35.4 | 36.8 |
| Percentage of world production | 1.0 | 1.7 | 2.2 | 2.6 | 4.0 | 4.0 | 4.2 |

*Includes sub-bituminous coal and lignite.

e: estimates.

Source: IEA.

Most of Canada's coal mines are located in the western provinces of British Columbia, Alberta and Saskatchewan. These three provinces account for almost all of Canada's coal production. Most mines in Alberta and British Columbia have been developed in the last 25 years. British Columbia is the principal exporter of metallurgical coal, while production from Alberta is used principally for power generation.

Apart from royalties, there are no provincial government interventions (incentives or restrictions) on exploration, production, employment, market or transport, but there are environmental restrictions by the provincial governments.

Crown royalties on energy resources vary from province to province and also by type of energy resource (coal, gas, oil or other). In Alberta, for instance, the coal royalty regime in 2004 is as follows:

- For Crown-owned sub-bituminous (plains): $0.55/tonne.
- For Crown-owned bituminous (mountain/foothills): before mine payout, 1% of mine mouth revenue; and after mine payout, 1% of mine mouth revenue plus 13% of profit.

Total royalties paid on coal in Alberta in financial year 2002-3 were about $10 million. In Saskatchewan, the Crown coal royalty schedule is 15% of the mine mouth value of coal (based on the sales contract or a price equal to the fair market value of the coal, as the case may be). Nova Scotia's royalty regime currently levies a coal royalty of $0.25 per tonne.

## INDUSTRY STRUCTURE

Production is almost exclusively from large surface mines, operated by privately owned companies. The restructuring of the Canadian coal industry was concluded in 2003. The Fording Canadian Coal Trust (Fording Trust) was formed on 28 February 2003, by Fording Inc., Teck Cominco Ltd., Westshore Terminals Income Fund, Sherritt International Corporation and the Ontario Teachers' Pension Plan. This new trust combined Fording, Luscar and Teck Cominco's metallurgical coal assets and created a subsidiary, the Elk Valley Coal Corporation. Fording's domestic thermal coal assets were transferred to the Luscar Energy Partnership, a 50-50 partnership between Sherritt International Corporation and the Ontario Teachers' Pension Plan.

The Elk Valley Coal Corporation has become the world's second-largest supplier of coking coal. It includes five mines in the Elk Valley of British Columbia and one mine in Alberta: Fording River, Coal Mountain, Greenhills, Elkview, Line Creek and Luscar, with a production capacity of approximately 25 Mt per year. Luscar Coal Ltd., owned by the Luscar Energy Partnership, operates seven surface mines in Alberta: Coal Valley, Obed Mountain, Highvale, Paintearth, Sheerness, Whitewood, Genesee; and three in Saskatchewan: Poplar River, Boundary Dam and Bienfait. Combined, these mines have a capacity of 40 Mt per annum of bituminous, sub-bituminous and lignite thermal coals used mainly for domestic electric power generation.

Other companies involve some Crown corporations and smaller privately-owned companies. In 1999, the federal government initiated a process to sell the operations of government-owned Nova Scotia Cape Breton Development Corporation DEVCO. In June 2000 the Cape Breton Development Corporation (DEVCO) Divestiture and Dissolution Act, providing for the sales of assets and the eventual liquidation of the corporation, was approved by Parliament:

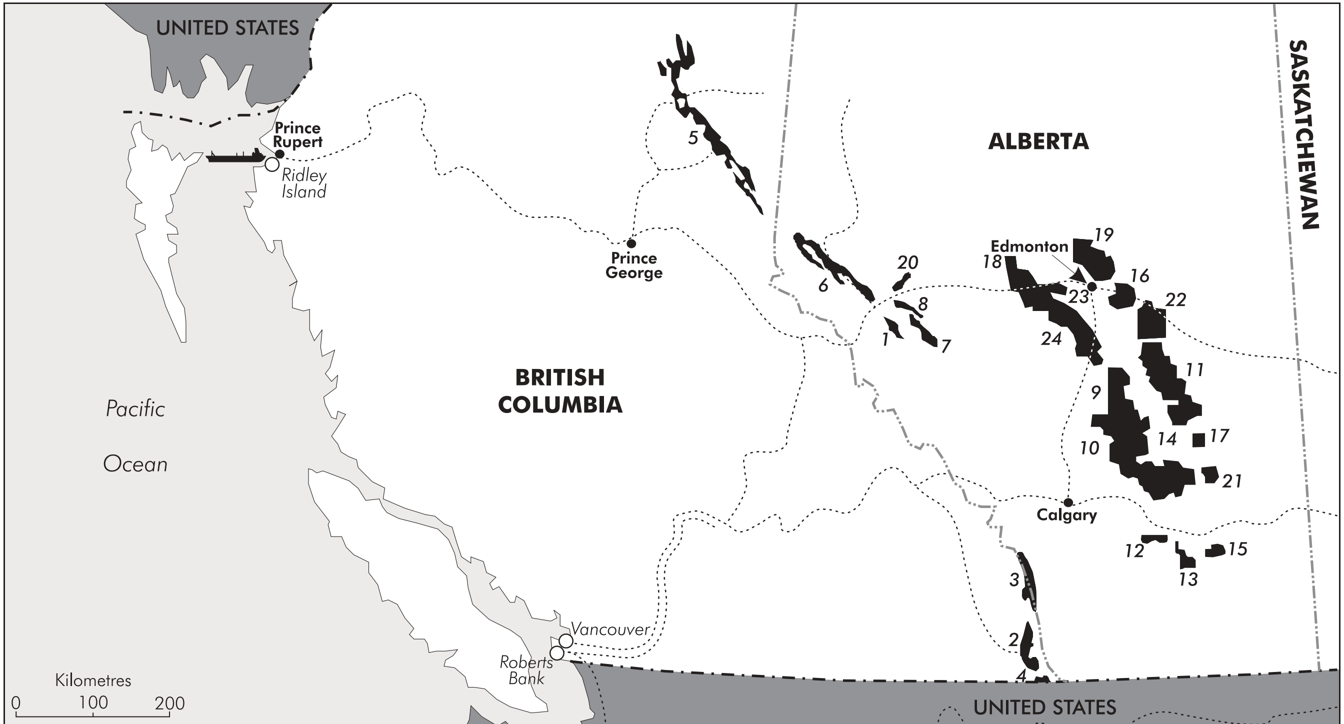
- DEVCO shut down its Phalen mine on 19 December 1999.
- Coal production at DEVCO's last mine, the Prince mine, stopped on 23 November 2001.
- DEVCO ceased operating its surface facilities, including the railway and the International Pier, at the end of 2001.
- The sale of DEVCO's surface assets to Emera, the parent company of Nova Scotia Power Inc. (NSPI), was concluded on 18 December 2001, completing the divesture process.

As a result of the liquidation of DEVCO, Canada provides no subsidies to the Canadian coal industry.

Transport costs over 1 000 kilometres from the west coast ports can account for about 50% of total FOB costs. Cost containment through restructuring has resulted in the high degree of concentration of coal companies in Canada.

Figure 22

## Coal Deposits and Infrastructure of Western Canada




○ Coal terminals

........ Major railways

1. Cadonim-Luscar
2. Crowsnest
3. Elk Valley
4. Flathead
5. Peace River
6. Smoky River
7. Coalspur
8. McLeod River
9. Alix
10. Ardley
11. Battle River
12. Blackfoot
13. Brooks
14. Drumheller
15. East Brooks
16. East Edmonton
17. Garden Plain
18. Mayerthorpe
19. Morinville
20. Obed Mountain
21. Sheerness
22. Tofield Dodds
23. Wabamum
24. Wetaskwin

Source: *Major Coalfields of the World*, IEA Coal Research 2002, London.

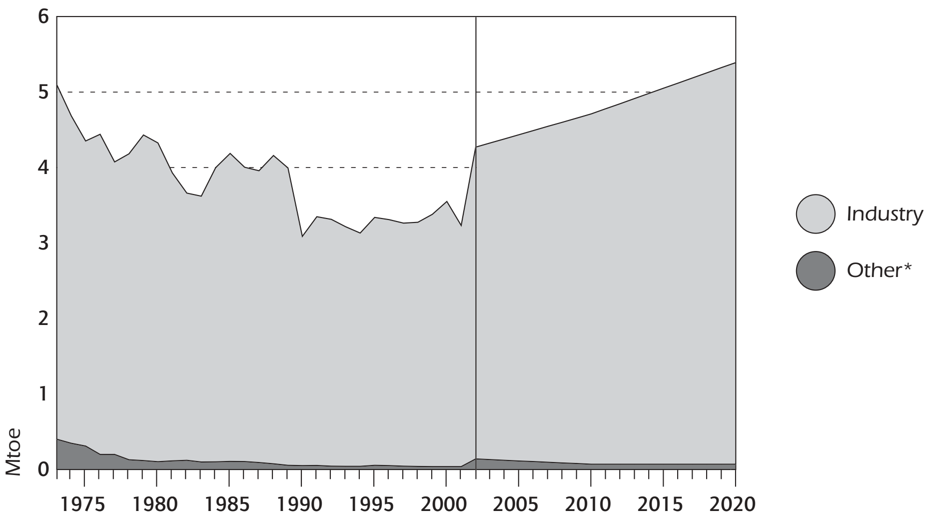
Average production costs are higher than those of many competitors and many mines survive on the basis of long-term contracts with FOB prices in excess of those received elsewhere for metallurgical coal.

## CONSUMPTION

Coal consumption in Canada is primarily for electricity generation. Demand has been stable since 1990. In the future, coal demand is expected to remain stable as electricity will rely more and more on other fuels. As a result, coal imports are likely to decrease and the total consumption of coal will be from domestic sources.

**Figure 23**

**Final Consumption of Coal by Sector, 1973 to 2020**




* includes commercial, residential, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

## TRADE

Steam coal exports remain a relatively small percentage of total exports, *i.e.* 13% in 2002 (see Table 18). On the other hand, more than half of coal imports are steam coal. While Canada is a net exporter of coal, it has become a net importer of steam coal, almost all coming from the United States.

Table 18

## Canadian Hard Coal Exports and Principal Destinations

(thousand tonnes)

| | *1980* | *1985* | *1990* | *1995* | *2000* | *2002e* |
|---|---|---|---|---|---|---|
| Total hard coal exports | 15 269 | 27 378 | 31 000 | 33 993 | 32 082 | 26 813 |
| **Coking coal exports** | 14 127 | 22 483 | 26 860 | 28 564 | 28 386 | 23 416 |
| Brazil | 626 | 899 | 1 108 | 1 094 | 1 471 | 1 526 |
| Chinese Taipei | 211 | 496 | 1 059 | 1 289 | 1 324 | 1 110 |
| Italy | 48 | 33 | 159 | 987 | 1 170 | c |
| Japan | 10 711 | 17 026 | 16 569 | 15 798 | 12 085 | c |
| Korea | 1 295 | 2 041 | 3 948 | 4 364 | - | c |
| Turkey | | | 51 | 262 | 819 | c |
| United Kingdom | | 330 | 645 | 1 194 | 1 093 | c |
| **Steam coal exports** | 1 142 | 4 895 | 4 140 | 5 429 | 3 696 | 3 397 |
| Japan | 412 | 1 516 | 1 933 | 2 483 | 1 244 | c |
| Korea | | 1 469 | 1 205 | 1 819 | - | c |

e: estimates.

c: confidential.

Source: IEA.

Table 19

## Canadian Hard Coal Imports

(thousand tonnes)

| | *1980* | *1985* | *1990* | *1995* | *2000* | *2002* |
|---|---|---|---|---|---|---|
| Total hard coal imports | 15 634 | 14 579 | 14 111 | 9 735 | 18 790 | 19 006 |
| **Coking coal imports** | 6 389 | 6 188 | 4 996 | 4 412 | 4 296 | 3 781 |
| United States | 6 389 | 6 188 | 4 992 | 3 992 | 4 296 | 3 781 |
| **Steam coal imports** | 9 245 | 8 391 | 9 115 | 5 323 | 14 494 | 15 225 |
| United States | 9 245 | 8 391 | 9 082 | 5 162 | 14 090 | 12 778 |

e: estimates.

Source: IEA.

# *TRANSPORT AND PORT INFRASTRUCTURE*

The principal rail routes for Canadian coal exports are from southeast British Columbia to Vancouver (Canadian Pacific railways), and from Alberta and northeast British Columbia to various west coast ports (Canadian National railways).

The two principal west coast ports are Ridley Island at Prince Rupert, and Roberts Bank, which is also an outlet for coal in from the Powder River Basin and other areas in the United States.

## CRITIQUE

Coal mining in Canada is now totally left to private activities since the government-held Cape Breton operations closed down in 2001. This is a commendable development since the last in-depth review. The coal mining industry recently restructured into one company producing metallurgical coal, mainly for export, and a company producing steam coal, mainly for domestic use.

The government's policy on environment, including climate change mitigation, will affect domestic demand for steam coal used by the electricity industry. In particular, it could affect the demand for imported coal from Ontario. Imported coal has a substantial share in power generation in that province and the government of Ontario announced the closure of the coal-fired power plants by 2007, essentially for environmental reasons. The economic viability of the coal industry is going to be affected by decisions on policies and instruments chosen to meet Canada's GHG emissions target and the development and deployment of effective clean coal technologies. This challenge also faces other fossil fuel extraction industries in Canada, although the cost for the coal industry could be larger (see Chapter 4 on the Environment).

In the last review, the team had found that transport costs were one area where viability could be assisted by policy changes. The federal government has been discussing the issue with the provinces. Transport Canada is currently in the process of drafting amendments to the Canadian Transport Act to improve competition in rail transportation of bulk commodities, including coal.

The review team has no recommendation to make.

# RENEWABLE ENERGY

## OVERVIEW

In 2002, renewable energy accounted for around 16% of the Canadian TPES.

The main component of renewables in Canada is hydroelectricity (11.7% of TPES in 2002). Hydroelectricity alone is made of 455 plants (234 being less than 10 MW), amounting to 67 121 MW of installed capacity, 355 TWh of electricity produced in 2001, being almost 60% of the total power generation in Canada. Hydroelectricity production is projected to grow by 20% between 2000 and 2020, but its share in the total supply is expected to remain stable or marginally decline (to around 10% of TPES by 2020).

Combustible renewables and wastes represented 4.4% of TPES in 2002. Most of it is produced from wood wastes used for industrial process heat, electricity generation (1.4% of total electricity generation in 2002) and space heating. Biomass, in the form of corn and other agricultural sources, is also used to produce ethanol for transportation use. With large quantities of fuel-wood used by the residential sector, significant volumes of renewable energy demand are, however, not captured in statistics. Future growth is expected to be strong, with a total energy supply from combustible renewables and wastes projected to grow by 80% to reach 19 Mtoe, or just over 5% of TPES by 2020.

Other renewable energy sources are still in their infancy in Canada, although the country is endowed with significant resources, particularly wood and wind. As a result, their share in TPES is still virtually negligible. Wind energy is the third most developed renewable energy source, with 313 MW of electricity capacity installed in 2003 and a potential for development in several locations, including coastal areas. Seven of 13 provinces and territories have some level of wind electricity generation. Solar photovoltaic (PV) installed capacity passed beyond 10 MW in 2003 and is considered to hold the potential for development in the on-grid urban sector.

## RENEWABLE ENERGY POLICIES

The main measures taken to support and guide the development of renewable energy in Canada are fiscal. The use of feed-in tariffs, portfolio standards and green certificates is not yet developed, although in September 2002 the Council of Energy Ministers mandated the *ad hoc* Federal-Provincial-Territorial Renewable Energy Working Group to examine different incentives and options for promoting renewable energy, and the possibility of introducing renewable portfolio standards.

NRCan has taken several initiatives to encourage the development and use of emerging renewable energy sources and technologies in the past. Among them are the Renewable Energy Deployment Initiative (REDI); the Wind Power Production Incentive (WPPI); the Market Incentive Program (MIP) for distributors of emerging renewable electricity sources; and government purchases of renewable electricity. About $475 million have been budgeted to be spent over several years for such initiatives to accelerate the use of emerging sources of renewable energy other than hydro. Initiatives not listed below belong mostly to R&D support (see Chapter 11).

Provinces also have their own support mechanism to promote renewables. British Columbia, Alberta and Newfoundland and Labrador have green electricity procurement policies for government uses. Several provinces are considering implementing renewable portfolio obligations (*e.g.* Ontario, New Brunswick). Québec is supporting the addition of an extra 1 000 MW of wind electricity capacity by 2012.

## RENEWABLE ENERGY DEPLOYMENT INITIATIVE

REDI was announced in December 1997, and came into effect on 1 April 1998. REDI is a 6-year, $24 million federal programme ending in 2004, designed to stimulate the demand for renewable energy systems for space and water heating and cooling. These systems include: active solar hot water systems; active solar air heating systems; highly efficient and low-emitting biomass combustion systems; and ground-source heat pumps (also known as earth energy systems, or geothermal or GeoExchange systems) – not eligible for an incentive.

Under REDI, NRCan has undertaken market development activities, in co-operation with renewable energy industry associations and other partners, and provided a subsidy for specific renewable energy systems in the form of a 25% refund of the purchase and installation costs of a qualified system, up to a maximum refund of $80 000. This subsidy is offered to the private sector and to federal departments and public institutions. In remote communities, businesses, institutions and other organisations may be eligible for a 40% refund of system investment costs up to $80 000. Eligible remote communities are the ones not connected to the North American electrical grid or natural gas distribution network and permanent settlements (5 years or more, and settlements with at least ten permanent buildings).

## WIND POWER PRODUCTION INCENTIVE

The WPPI was announced in the December 2001 budget and is intended to encourage electric utilities, independent power producers and other stakeholders to gain experience in wind power. WPPI provides financial support for the installation of 1 000 MW of new wind capacity until 2007, covering 25-50% of the additional cost incurred by wind energy compared to conventional sources, amounting to around $1 per kWh produced. This incentive is available to electricity producers for the first ten years of a project. The WPPI encourages participation from prospective producers in all regions. With a public investment of $260 million, WPPI is expected to leverage approximately $1.5 billion in capital investments across Canada and achieve a reduction in GHG emissions of 3 Mt of $CO_2$-equivalent by 2010. The ceiling per province of eligible capacity is 300 MW.

NRCan is implementing this programme and ensures that energy producers in every province and territory have the opportunity to take advantage of it by setting a minimum and maximum capacity for every province and territory. To be eligible, a wind farm must be commissioned between 1 April 2002 and 31 March 2007; be independently metered at the point of interconnection with the electricity grid; and must have a minimum nameplate capacity of 0.5 MW. In northern and remote locations, the minimum capacity is 20 kW.

## *MARKET INCENTIVE PROGRAM FOR DISTRIBUTORS OF EMERGING RENEWABLE ELECTRICITY SOURCES*

The Market Incentive Program (MIP) is a $25 million programme for distributors of emerging renewable electricity sources and is part of the government of Canada Action Plan 2000 on Climate Change. The MIP goal is to encourage electricity distributors to experiment with measures to stimulate sales of electricity from emerging renewable energy sources other than hydro with low environmental impact to residential and small business customers. The financial support covers the costs incurred by the electricity distributor for developing and implementing marketing and awareness campaigns aimed at encouraging customer participation in purchasing electricity from emerging renewable energy sources. These energy sources cover all production by Qualifying Generation Facilities (QGF) which are newly built facilities, or built as expansions or modification of existing facilities, commissioned on or after 1 April 2001. Both the facilities and the electricity (Qualifying Electrical Energy) involved in such projects must obtain and maintain a third-party certification acceptable to the government of Canada, such as EcoLogo^M of the Environmental Choice Program[26]. Funding is available through the MIP until 31 March 2006 and covers up to 40% of eligible costs of an approved project for a maximum of $5 million per recipient. As of January 2004, three companies benefited from this support:

26. The EcoLogo^M is a registered mark of Environment Canada.

Maritime Electric Corporation Ltd., Charlottetown, Prince Edward Island; New Brunswick Power Corporation, Fredericton, New Brunswick; and SelectPower Inc., Guelph, Ontario.

## *GOVERNMENT PURCHASE OF ELECTRICITY FROM RENEWABLE SOURCES*

Following a 1994 recommendation of the Task Force on Economic Instruments and Disincentives to Sound Environmental Practices, NRCan studied the feasibility of having the federal government buy some of its electricity from emerging renewable energy sources other than hydroelectricity. The goals are to provide a "first customer" to help interested utilities gain experience with different electricity products; to achieve emissions reductions in federal operations; and to leverage first purchases to create viable green power markets.

In December 1997, NRCan began purchasing green electricity from ENMAX, Calgary's electric system within a ten-year agreement to supply 10 GWh per annum to NRCan's Alberta facilities. Environment Canada also signed an agreement with ENMAX for 2 GWh per annum of green electricity from wind energy for the electricity requirements in Alberta. These two agreements are expected to displace more than 10 000 tonnes of $CO_2$ annually. In September 2000, NRCan signed a ten-year agreement with SaskPower, Saskatchewan's electric utility, and is receiving about 32 GWh annually of wind power for its facilities in Saskatchewan. Early in 2001, NRCan signed a ten-year agreement with Maritime Electric from Prince Edward Island for purchasing annually 13 GWh of electricity from wind energy sources. Agreements with Saskatchewan and Prince Edward Island are expected to achieve 40 000 tonnes of $CO_2$-equivalent emissions reductions annually for the government of Canada.

Under the Action Plan 2000 on Climate Change, the federal government envisages to purchase an additional 400 GWh or so of electricity from renewable energy sources from Nova Scotia, Ontario and New Brunswick, and with additional purchases from Alberta. These purchases will result in a further reduction in GHG emissions of about 200 000 tonnes of $CO_2$ annually.

The Climate Change Plan of 2002 envisages implementing a target of 10% of new generating capacity from emerging renewable energy sources as part of its second phase.

## ***CRITIQUE***

Long gestation periods for hydroelectricity projects and large upfront investment costs are obstacles to hydroelectricity development, not to mention environmental constraints that require additional project expenditures (such as securing no net fish loss as required by the Fisheries Act). Large hydroelectricity projects (beyond 50 MW) are increasingly difficult to set up because of local environmental opposition. This is why the share of hydroelectricity is expected to remain stable or decline. However, the industry assesses the technically feasible hydroelectricity remaining potential to be large, around 118 GW. In this respect, the most important provinces are Québec (35 GW) and British Columbia (27 GW). The review team found no reason why hydroelectricity, in particular small hydro less than 50 MW, should be eliminated from renewable energy sources which are eligible to support. When economically necessary, given the large potential of Canada, hydroelectricity should receive adequate consideration and be included in renewable energy support mechanisms to be developed and implemented.

The main measures taken to support and guide the development of renewable energy in Canada are subsidies under various programmes. However, care should be taken to build in an incentive to cost reduction in these subsidy programmes, to ensure better cost-effectiveness than a flat subsidy scheme could do. As most existing schemes in Canada today include a maximum limit to the amounts of total subsidy disbursed or to the total capacity installed that could benefit from the support, the team found commendable government efforts to carefully measure the subsidy schemes in order to maximise economic efficiency and to avoid fiscal expenditures growing beyond efficiency with the growth of renewable energy. The team also found commendable the efforts of the government to consider the advantages of market mechanisms. These efforts should be promoted further, considering the relative advantages of market-oriented incentives, compared to the effectiveness and cost of the existing incentives to promote renewables.

Many other IEA countries have introduced either feed-in tariffs or renewable portfolio standards. The advantages and disadvantages of these schemes should be thoroughly examined. In this context, it is a positive development that an *ad hoc* Federal-Provincial-Territorial Renewable Energy Working Group is considering new measures to promote renewable energy, including the introduction of renewable portfolio standards. It is also noteworthy that several provincial governments are considering portfolio standards. Noting the strong authority of provincial governments and very diverse endowment of renewable energy among different provinces and territories, the implementation of such portfolio standards may start from provinces. This should lead to the implementation of market mechanisms to promote the development of economically viable renewable energy solutions and also lead to some $CO_2$ emission mitigation while diversifying the energy supply. Given, however, the large availability of fossil fuels and renewable energy sources in Canada, and given the size and population density of Canada, it may be of specific interest to public finances to concentrate the support mechanisms on the development of high-value applications of renewable energy. This should be promoted further and Canada would benefit from federal support eventually concentrating on such deployment.

## RECOMMENDATIONS

*The government of Canada should:*

- *Investigate further advancement of hydroelectricity.*
- *Consider new market-oriented incentives to promote renewable energy.*
- *Continue to facilitate production and use of renewable energy and concentrate its development and deployment on niche markets and high-value applications (*e.g. *energy supply to remote areas).*

# ELECTRICITY AND NUCLEAR

## ELECTRICITY

### INDUSTRY STRUCTURE

Electricity is primarily within the jurisdiction of the provinces and Canada's electricity industry is organised along provincial lines. Electricity generation and transportation within a province falls under provincial jurisdiction. Inter-provincial and international electricity trade and facilities fall under federal jurisdiction.

In most provinces the electricity industry is highly integrated with the bulk of generation, transmission and distribution provided by a few dominant utilities. Although some of these are privately-owned, most are Crown corporations owned by the provincial governments. In some cases, relatively small generators also exist, but seldom in direct competition with the dominant Crown corporation. Municipally-owned distributors are common.

Each province has a different industry structure and has been carrying out distinct restructuring plans. Typically, provinces and territories historically established a single government organisation – such as a commission or board – to be responsible for generation, transmission and distribution of electricity. In most cases, the organisation was incorporated at a later date, but generally with the provincial government as the sole shareholder. Incorporation generally involved narrowing the activities of the corporation to electricity and relinquishing other operations such as gas supply.

Below is a brief description of some of the provinces' industry structure.

In **Alberta**, there are four major electricity utilities: TransAlta Utilities Corporation, ATCO Limited, ENMAX and EPCOR. TransAlta and ATCO Power are investor-owned, while EPCOR is owned by the city of Edmonton and ENMAX by the city of Calgary. Transmission facilities are owned by investor-owned companies AltaLink and ATCO. The two largest municipalities, Edmonton and Calgary, also own transmission facilities located within their municipal service areas. Ownership of generation facilities was deregulated in 1998 with the introduction of a competitive market for electricity generation. Since then, Alberta has attracted a number of new private investors and 3 000 MW of new generation facilities have been developed. Alberta's oil sands are an important source of that new power supply, with co-generation providing heat to support operations and generating electricity for sale in the market-place. Coal accounts for 48% of electricity generation in Alberta, with natural gas accounting for 42% and renewables, such as wind, hydro and biomass, for about 10%.

In **Ontario**, electricity is produced mainly from nuclear power (43%), from coal and oil (25%), hydro (25%) and natural gas and other (7%). Ontario Power Generation Inc. (OPG), which has assumed all of the generation assets of the former Ontario Hydro, is a provincially-owned corporation that generates three-quarters of the electricity in Ontario. OPG operates 82 power stations: of which 69 hydroelectric, 6 conventional thermal and 5 nuclear. Bruce Power, a company controlled by Cameco and TCPL, operates an eight-unit reactor power station under lease. Hydro One is a separate company that has assumed the extensive transmission and distribution assets of the former Ontario Hydro. Hydro One transmits wholesale electric power to 100 or less municipal utilities that in turn retail it to customers in their service areas. In total, Hydro One and the municipalities serve about four million customers. About 108 large industrial customers are supplied directly with power and Hydro One distributes power to more than 962 000 small business and residential customers in rural and remote areas.

In **British Columbia**, electricity is almost entirely generated from hydro (90%). BC Hydro, a provincial Crown corporation, provides electrical services throughout the province (except for the city of New Westminster and the southern interior served by Aquila Networks Canada (ANC), a 100% subsidiary of Aquila Inc.). British Columbia Hydro is the third-largest electricity utility in Canada. British Columbia's mainland gas operations and its rail operations were privatised in 1988. Several utilities were created, including British Columbia Power Export Corporation (Powerex), which was established as a power marketing subsidiary of BC Hydro and also to trade electricity with the US. With the bulk of its generation being hydro, BC Hydro has significant abilities to engage in electricity banking, *i.e.* storing water in reservoirs during off-peak periods for generation and dispatch or export during peak periods when prices are higher. BC Transmission Corporation, established in 2003 as a wholly government-owned corporation, operates, maintains and plans the transmission grid. There are eight municipal distributors in the ANC area.

In **Québec,** Hydro-Québec is Québec's Crown corporation responsible for the generation, transmission and distribution of most of the electricity sold in Québec. It also trades in electricity with neighbouring provinces and the US. 93% of Québec's electricity is generated from hydro.

In **Manitoba**, Manitoba Hydro is a Crown corporation which produces almost all the province's electric power. It also distributes electricity throughout the province, except for the central portion of Winnipeg, which is served by the municipally-owned Winnipeg Hydro, sold to Manitoba Hydro. 95% of Manitoba's electricity is generated from hydro.

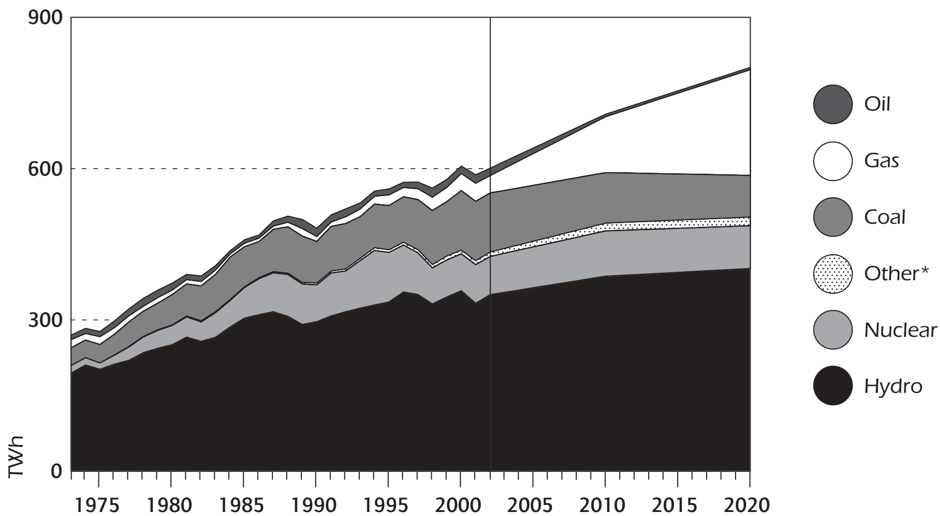
In **New Brunswick**, the New Brunswick Power Corporation (NB Power) – a Crown corporation – owns and operates 15 generating stations (including one nuclear) and also purchases electricity from Québec. New Brunswick also trades electricity with Nova Scotia and northern Maine (US).

# ELECTRICITY GENERATION

Fuel use in electricity generation is illustrated in Figure 24. Reaching 601 TWh in 2002, electricity output grew on average by 2.1% per annum since 1990. Hydro remains the dominant fuel used with almost 60% of the generation in 2002, followed by coal (19.5%), nuclear (12.6%), gas (5.7%) and oil (2.4%). Gas is the fuel showing the fastest growth. Since 1990, the share of coal grew (from 17% in 1990), and gas (from 2.0% in 1990), in part replacing a fall in hydro (from 62% in 1990 to 58% in 2002), nuclear (from 15%) and oil (from 3.4%).

**Figure 24**

**Electricity Generation by Source, 1973 to 2020**




* includes geothermal, solar, wind and combustible renewables.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

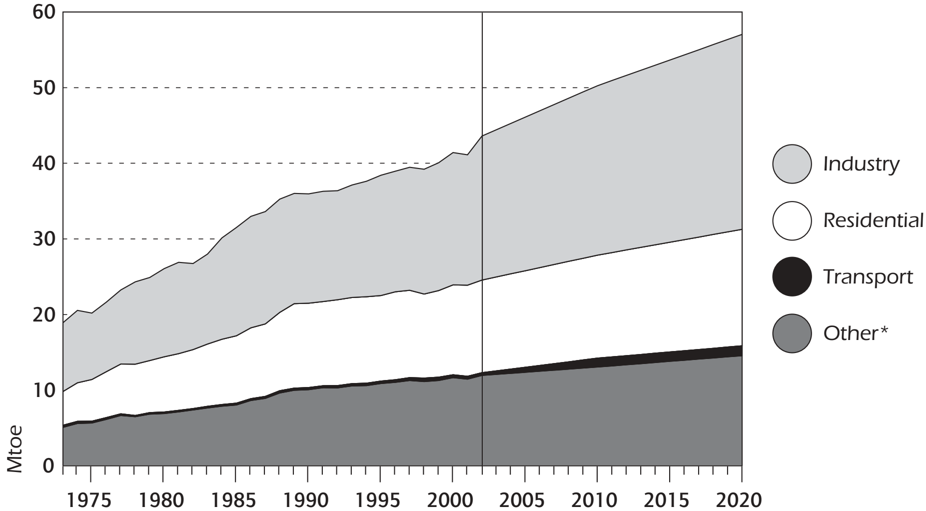
Total electricity output is expected to grow by an average rate of 1.8% between 2002 and 2020. The shares of each fuel in the mix are expected to change significantly, with a larger share of generation being produced from gas (26% in 2020 against close to 6% in 2002), and reduced shares of generation from hydro (50% in 2020 against 58% in 2002), coal (10% in 2020 against close to 20% in 2002), nuclear (11% in 2020 compared to nearly 13% in 2002) and oil (0.5% in 2020 compared to 2.4% in 2002).

# ELECTRICITY CONSUMPTION

Growth in electricity consumption is illustrated in Figure 25. Canada is the third-largest consumer of electricity per capita in the OECD, after Norway and Iceland.

Figure 25

**Final Consumption of Electricity by Sector, 1973 to 2020**




* includes commercial, public service and agricultural sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2003; and country submission.

# EXTERNAL ELECTRICITY TRADE

Most provinces have agreed to provide cross-provincial transmission access in accordance with the Agreement on Internal Trade.

In 2002, Canada was the world's fifth-largest electricity producer (after the US, China, Japan and Russia) and the third-largest electricity exporter, with 39 TWh, after France and Germany.

Trade is mainly carried out with the neighbouring US states. Electricity trade with the US is encouraged by several factors. Price differences make exports to the US profitable and attractive to US buyers; electricity supply systems in the US and Canada can have different seasonal peaks which make trade in surpluses possible. Electrical systems in Canada can experience their peak demand in winter, while most electrical systems in the US have their peak in summer. Canadian hydraulic sources are also attractive on environmental grounds to replace fossil sources.

Canada has historically been a net exporter of electricity to the US. Exports account for about 7 to 9% of total Canadian generation. They represent less than 2% of total US electricity demand. However, the proportion of demand met by Canadian exports in some regions of the US can be considerably higher, for example around 13% in New England and 6% in New York. Exports originate mainly from the hydro-rich regions of Québec, Manitoba and British Columbia, which together accounted for 80-85% of total electricity exports over the past five years. In western Canada, Alberta exporters have made inroads into Pacific-northwest US markets. A recent policy to upgrade transmission combined with improved transmission access to US markets will support future electricity exports by competitive Alberta power producers in Pacific-northwest markets. Net exports have typically been in the range of 35-45 TWh per annum with significant variations due to weather-sensitive hydroelectricity production. Exports have declined since 2000, reflecting increased domestic demand combined with no corresponding increase in generating capacity.

A growing quantity of exports is traded in spot-related short-term deals, demonstrating a shift from long-term contracts. Many new players are engaging in trade, mainly independent traders. Their number increased from one export licence-holder in 1993 to 40 in 2002, but 99% of external trade is still carried out by unbundled traditional utilities retaining a share of export markets by creating marketing subsidiaries.

Imports amounted to 15 TWh in 2001 and seem to be growing. A specific reason for this growth is the removal from service of a number of nuclear plants in Ontario from 1997 onwards. Importers in hydro-rich regions such as British Columbia and Québec also took advantage of energy banking opportunities to increase trading revenues after transmission access was improved in both Canada and the US with the implementation of the US Federal Energy Regulatory Commission's (FERC) Order 888 from 1996 onwards, thus boosting imports during off-peak periods of production in the US.

The combination of a decline in exports and increasing imports is resulting in an overall decline in net exports from 40 TWh to around 25 TWh in 2002.

## ELECTRICITY RELIABILITY

A major blackout occurred in August 2003 (see box) that drew attention to reliability standards. A US-Canada Power System Outage Task Force was created after the blackout to investigate and formulate regulatory solutions to improve the functioning of the grid and secure trade between the two countries. The task force completed a report on the causes of the blackout in November 2003 and followed up with a second report in April 2004 that has provided policy recommendations. Recommendations call for a strong commitment by the electricity supply industry, its related organisations as well as the governments and regulators to adhere to strict reliability standards to operate the bulk power systems, including the application of penalties for non-compliance. Recommendations also called for internalising the costs of increased reliability.

## The August 2003 Blackout in the US and Canada

North America's worst blackout struck the mid-west and north-eastern United States and south-western Canada around 4.13pm on 14 August 2003. The event affected Ontario, Québec, New York, northern New Jersey, Massachusetts, Ohio, Pennsylvania, Michigan, Connecticut and Vermont. According to the North American Electric Reliability Council, around 62 000 MW of generation was shed and power was cut to approximately 50 million people over a 9 300 square mile area.

A joint US-Canadian task force (the US-Canada Power Outage Task Force) was immediately established to investigate the event. The main succession of events went as follows:

- 12.05pm – 1.31pm: Three generating units tripped in Ohio, changing the power flow over the transmission system.
- 2.02pm – 4.10pm: Eight 345-kV transmission lines disconnected in Ohio.
- 4.10pm: A series of transmission lines disconnected across Michigan and northern Ohio. Transmission lines disconnected in northern Ontario and New Jersey. At this point, the Eastern Interconnection separated. To the north lay New York City, northern New Jersey, New York, New England, the Maritime provinces, eastern Michigan, the majority of Ontario and Québec.
- 4.11pm: The Ontario system separated from New York, with most of Ontario blacking out.
- 4.13pm: The majority of the northern portion of the Eastern Interconnection, which had been separated as a result of the cascading disconnections, was blacked out.

Power was largely restored to most of the main population centres over the following two days. In Ontario, Premier Eves declared a state of emergency on 14 August and asked all non-essential and non-emergency workers to stay at home. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored.

A combination of electrical, computer and human factors was responsible for the problem. The main causes included:

- Inadequate vegetation management next to high-voltage transmission lines.
- Failure to ensure operation within secure limits.
- Failure to identify emergency conditions and communicate that status to neighbouring systems.
- Inadequate operator training.

- Inadequate regional-scale visibility over the power system.
- Dysfunction of a control area's SCADA/EMS system.
- Lack of adequate backup capability of the system.

The April 2004 final report defines 46 recommendations grouped into four substantive areas:
Group 1 – Institutional Issues Related to Reliability.
Group 2 – Support and Strengthen NERC's Actions of February 2004.
Group 3 – Physical and Cyber Security of North American Bulk Power Systems.
Group 4 – Canadian Nuclear Power Sector.

Source: Author's summary of US-Canada Power System Outage Task Force, November 2003, *Interim Report: Causes of the August 14$^{th}$ Blackout in the United States and Canada*; and April 2004, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*.

## INTER-PROVINCIAL ELECTRICITY TRADE

Inter-provincial electricity flows account for about 10% of total Canadian electricity consumption. Total flows have remained at close to 50 TWh. Eastern Canada accounts for over 80% of the total transfers, while western Canada accounts for the balance[27]. Largest transfers are between Labrador and Québec (30-35TWh per annum). More transmission capacity is planned between Ontario and Québec, and between Alberta and Saskatchewan.

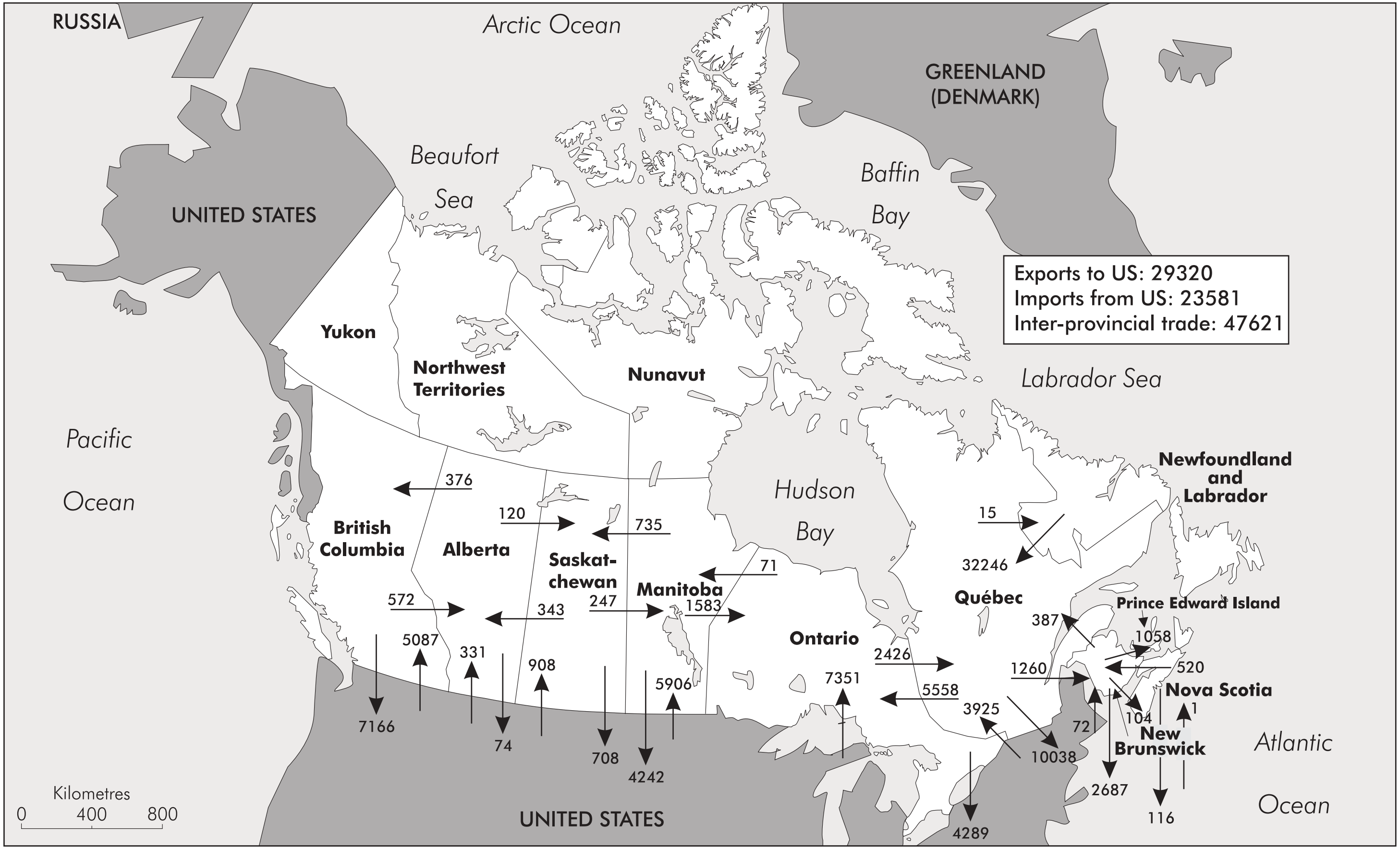
In October 1998, federal and provincial energy ministers approved a legal text for the energy chapter to be a part of the Agreement on Internal Trade. It provides for non-discriminatory, open transmission access across the provincial jurisdictions and dispute resolution procedures. Energy ministers passed the text of the chapter to trade ministers to conclude. Direction was sought from the Committee on Internal Trade in late 1999. Negotiations are yet to be completed. Once these are completed, the energy chapter will provide limited uniform access to cross-territory transmission of electricity. It will also provide a mechanism to settle disputes.

The Federal-Provincial-Territorial Electricity Transmission Working Group was established after the blackout by the Federal, Provincial and Territorial Energy Ministers in 2003. One of the mandates of this Transmission Working Group is to address constraints to regional transmission.

27. National Energy Board, *Canadian Electricity, Trends and Issues*, Energy Market Assessment, Calgary, 2001.

Figure 26

**Electricity Trade*** (GWh)




* statistics for inter-provincial trade are for the year 2002 while data for exports to the United States are for the year 2003.
Sources: Natural Resources Canada statistics derived from Statistics Canada *Electric Power Statistics*. 57-001-XIB (January 2003); and National Energy Board C*anadian Electricity Exports and Imports* (December 2003).

# ELECTRICITY REFORMS AND REGULATIONS

As in many other countries, many provinces have been progressively introducing reforms through modifying the industry structure, unbundling vertically integrated monopolies, enabling third-party access to the transmission grids and introducing retail and wholesale competition. Reform has been progressing at a different pace across Canada. In 2003, retail competition was introduced in Alberta and Ontario, and wholesale competition was effective in the provinces of British Columbia, Alberta, Manitoba, Ontario, Saskatchewan and Québec (see Table 20).

Below is a brief description of the situation in some of the provinces.

## Alberta

The Alberta Electric Utilities Act, 1995 established open transmission access, a competitive Power Pool, and an independent Transmission Administrator responsible for planning and financial management of the transmission system. Since 1 January 1996, all electricity, whether generated in Alberta or imported, has been sold into a power pool. The distributors and exporters purchase electricity according to a market price set each hour. The Alberta Electric Utilities Amendment Act, 1998 introduced retail competition, effective from 1 January 2001. TransAlta Utilities was the first Canadian utility to successfully apply for a Federal Energy Regulatory Commission marketers' licence in the United States and has moved quickly to establish its presence in the US market. The Alberta Energy and Utilities Board (EUB) was created, effective 15 February 1995, in particular to regulate electricity in the development of the market. Increased competition – and a solution to stranded costs of restructuring – was ensured by two auctions of the power purchase agreements from the pre-1996 power plants that took place in 2000. The plants concerned continue to operate as regulated utilities on a cost-of-service basis. Retail access was introduced in January 2001.

The Electric Utilities Act, 2003 introduced a new industry structure, replacing the former Power Pool and separate Transmission Administrator into a new Independent System Operator or ISO. The Alberta ISO is responsible for operating the competitive power pool, conducting system dispatch, administering load settlement and assumes the responsibility to manage and develop the provincial transmission system. The EUB also approves the electricity regulated rate for the majority of eligible residential, farm and small commercial customers. Municipalities and rural co-operatives approve the costs for electricity service in their service areas.

The retail market was opened at the height of the California electricity crisis, when western North American electricity and natural gas prices were very high. Alberta, as part of an interconnected market which includes California and the northwestern US, also experienced very high market prices, with

## Table 20

## Status of Canadian Electricity Restructuring

| | *Wholesale access* | *Retail access* | *Comment* |
|---|---|---|---|
| British Columbia | yes | large industrial consumers | – BC Hydro retail prices are frozen until 31 March 2004<br>– future prices will be regulated by the British Columbia Utilities Commission based on approved costs<br>– plans to introduce stepped rates in retail access in 2005 |
| Yukon Territory, Northwest Territories and Nunavut | no | no | - prices are regulated by public utility boards<br>- small, dispersed markets<br>- no transmission interconnections with the provinces |
| Alberta | yes | yes | - wholesale prices are established in the market managed by the Independent System Operator; pass-through to consumers who have various purchase options<br>- competitive retail market for all consumers<br>- eligible smaller residential, farm and small commercial consumers have the option of a regulated rate |
| Saskatchewan | yes | cities of Saskatoon and Swift Current | - retail prices are subject to government approval |
| Manitoba | yes | no | - retail prices are approved by the Manitoba Public Utilities Board<br>- co-ordination agreement with the Midwest Independent System Operator (September 2001) |
| Ontario | yes | yes | - wholesale prices are established in the market administered by the Independent Market Operator<br>- interim pricing plan with low consumer price at 4.7 cents per kWh for first monthly 750 kWh (5.5 cents above); new pricing mechanism to be implemented by 1 May 2005<br>- retail access for large industrial consumers to be implemented on 1 April 2004 |
| Québec | yes | large industrial consumers | - retail prices are regulated by the Régie de l'énergie du Québec<br>- rates are frozen until 2004 |
| New Brunswick | yes | large industrial consumers, planned for 2003 | - retail prices are regulated by the Board of Commissioners of Public Utilities<br>- the province is implementing restructuring pursuant to its White Paper on Energy Policy |
| Prince Edward Island | no | no | - P.E.I. imports most of its electricity from New Brunswick<br>- retail prices cannot exceed 110% of that paid for comparable service in New Brunswick (under the Maritime Electric Company Act) |
| Nova Scotia | new market structure to be implemented in 2005 | new market structure to be implemented in 2005 | - real prices are regulated by the Nova Scotia Utility and Review Board<br>- a "staged" approach to restructuring |
| Newfoundland and Labrador | no | no | - retail prices are regulated by the Board of Commissioners of Public Utilities<br>- study of restructuring has been undertaken |

Source: National Energy Board, 2003, *Canadian Electricity – Exports and Imports*, Calgary.

wholesale prices in 2000 ($133/MWh) triple the value of the previous year and continuing into early 2001.

Most small consumers were purchasing electricity through their local distributors who in turn were purchasing much of their needs at spot prices. These distributors applied to the regulator to raise retail electricity prices to pass higher costs on to customers.

To provide interim relief to Alberta customers from the impacts of unstable North American electricity markets and higher than anticipated prices, the government placed a one-year temporary retail price cap on electricity for 2001 at $110/MWh or 11 cents per kilowatt-hour. Wholesale prices in 2002 declined to pre-2000 prices and averaged $44.00/MWh in that year. Electricity prices continue to stabilise, reflecting the new generation that has come on line. Nonetheless, Alberta's electricity wholesale prices remain sensitive to continental natural gas prices and seasonal factors such as the weather.

Unlike the case in Ontario (see below), the price cap was set at a relatively high level, well above long-run marginal cost in order to preserve a signal for new investments. Investment in new generating capacity, which kept pace with growth in peak load, is continuing. A further 5 GW (approximately 40% of existing capacity) is expected to be constructed in the period 2003-2006.

## British Columbia

BC Hydro, BC Transmission Corporation and Aquila Networks Canada (ANC) are regulated by the British Columbia Utilities Commission (BCUC) to ensure in particular that open access is guaranteed. Independent power producers and municipal utilities are not subject to BCUC regulation unless they sell electricity outside their service area. BCTC's wholesale transmission tariff is FERC-compliant and Powerex has a Power Marketing Authorisation from FERC to sell power in US markets.

In November 2002, the British Columbia government released its comprehensive Energy Plan, aimed at preserving the province's low-cost heritage power and public ownership of BC Hydro, maintaining reliable supply and increasing private-sector opportunities and environmental responsibility.

The plan stipulates that no nuclear power sources will be developed in BC. It addresses electricity supply, natural gas and oil offshore exploration, and coal-bed methane development.

The plan includes several action items to achieve these objectives:

- The BC Utilities Commission (BCUC) again regulates BC Hydro rates.

- Low-cost power will be preserved in a Heritage Contract for energy supply between BC Hydro Generation and BC Hydro Distribution.
- Least-cost resources will be acquired with BCUC oversight.
- A new corporation, BC Transmission Corp., will improve access to transmission for customers and independent power producers.
- "BC Clean Energy"[28] will be encouraged by a voluntary goal of 50% new electricity coming from clean resources, new stepped rate structures for conservation and energy efficiency, updated energy efficiency legislation and streamlined regulatory processes.

## Ontario

In October 1998, the Energy Competition Act was passed to restructure Ontario Hydro and to introduce competition in the province's electricity market. Ontario Hydro was then split into five separate entities:

- A generating entity, Ontario Power Generation Inc. (OPG).
- A transmission, distribution and energy retailing entity, Hydro One Inc. (Hydro One).
- A wholesale market operator and transmission monitoring entity, Independent Market Operator (IMO).
- The Ontario Electricity Financial Corporation (OEFC) to manage part of Ontario Hydro debt liabilities.
- The Electrical Safety Authority.

To avoid abuse of the dominant position by OPG which owns and operates the former Ontario Hydro generation facilities, a 10-year plan to mitigate its market power was developed, including: capping the Ontario sales of OPG to 3.8 cents per kWh for four years after the beginning of market opening; forcing a reduction of OPG's fuel generating capacity considered able to influence spot market prices to 35% or less within 42 months of the market opening; and capping OPG's share of total generation to 35% and other suppliers to 25% within ten years after the market opening. The implementation of this plan led OPG to lease the Bruce nuclear power plant (see section on Nuclear below). The 10-year plan also required Hydro One to increase its interconnection capability by 2 000 MW within 3 years of open access. This measure led to the Michigan Phase Shifter Project (600 MW) and a plan to build a new Ontario-Québec Inter-Tie (1 250 MW).

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28. BC Clean Energy refers to emerging renewable energies such as small hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as combined heat and power, energy from landfill gas and municipal solid waste, fuel cells and efficiency improvements at existing facilities.

The Ontario Energy Board is responsible for the regulation of the electricity market in Ontario (licensing, rate determination, market monitoring, reviewing IMO market rules).

The process to establish competition and its related institutions took a longer time than expected and was completed in May 2002. All customers, regardless of size, had the right to choose their electricity supplier. Approximately 1.1 million residential consumers, about one-quarter of the total, had made arrangements for a fixed-price contract by the time the market was a few months old. While prices during the spring were lower than regulated prices, a combination of an unusually hot summer and delays in bringing nuclear generating capacity back into service led to prices that were much higher than the government had anticipated. Combined with higher consumption, bills to Ontario consumers not covered by a fixed-price contract rose by approximately 30%, generating dissatisfaction.

As a result, in late 2002, the government passed legislation that froze prices for small consumers and institutional consumers (*e.g.* hospitals, schools, municipal buildings) at the level it was before the opening of the market ($43/MWh) until at least May 2006, compensated consumers for the additional amounts they had paid up to that point, froze rates for transmission and distribution of electricity, and empowered itself to change these rates previously determined by the regulator. Despite these changes, the wholesale market was left in place and the government is required to make up any difference between the wholesale cost of electricity and the frozen price. The new government, in place since 2003, has announced a plan to raise prices to cover costs.

## Saskatchewan

The legislature is the regulatory body. There are no plans to modify the structure of the current system, where SaskPower is the sole provider of electricity to the province's customers. SaskPower however introduced an open access transmission tariff in July 2001 to facilitate access to third parties to the grid.

## Québec

In Québec, since December 1996, the Régie de l'énergie (Québec Energy Board) has provided a regulatory framework for energy distribution. Electricity rates are subject to the board's approval. The policy of Hydro-Québec is to maintain rate stability through cross-subsidisation between residential customers and smaller industrial customers. Hydro-Québec's transmission and distribution activities are subject to regulation based on the cost of service for those activities. For power generation, the government of Québec dictates the initial conditions for establishing supply rates which represent the energy portion of the customer's bill.

Québec's wholesale market has been open since 1 May 1997. In the same year, Hydro-Québec obtained a US FERC Power Marketing Authorisation. The wholesale market comprises 11 distributors: Hydro-Québec Distribution, nine distributors operating municipal systems and one regional electricity co-operative. TransÉnergie, a division of Hydro-Québec, operates the transmission system in Québec. The Act Respecting the Régie de l'énergie states that the government may, when it deems appropriate, ask the Régie de l'énergie to look into the possibility of opening up the retail market. Hydro-Québec considers that there would be no tangible benefits to consumers from retail competition. Accordingly, it does not expect any initiatives on this matter in the short term and does not intend to promote opening of the market.

## Manitoba

In 1996, Manitoba Hydro became a full member of the Mid-Continent Area Power Pool. Subsequently, in 1997, the Manitoba Hydro Amendment Act allowed wholesalers of electricity open access to Manitoba Hydro transmission facilities. The act prohibits retail competition.

## New Brunswick

In 1997, the government of New Brunswick announced support for deregulation and competition. An open access tariff for certain transactions using New Brunswick Power's transmission system was announced in January 1998. In January 2003, New Brunswick passed the Electricity Act, providing the legal framework to reform the province's electricity market and to reorganise NB Power. The new legislation provides for the establishment of the rules governing an open wholesale market for the province's three municipal distribution utilities and the 42 largest industrial customers that are directly connected to the transmission system. The retail electricity market is not affected by this new law. Under the new act, NB Power Corporation will officially become NB Power Holding Corporation with four subsidiaries, that will remain Crown corporations:

- NB Power Generation Corporation – responsible for the operation of the non-nuclear generation assets.
- NB Power Nuclear Corporation – responsible for the operation of Point Lepreau.
- NB Power Transmission Corporation – will own and operate the high-voltage transmission system in the province and serve as a common carrier providing access to all parties wishing to use the transmission system for delivery of electricity within the province for exports, or for wheeling through by other parties.
- NB Power Distribution and Customer Service Corporation will be responsible for the wires and customer service from the transmission lines to the homes and businesses of their customers.

## ELECTRICITY PRICES

Electricity prices are regulated at the provincial level. Since electricity in most provinces is regulated on a cost-of-service basis, prices reflect the costs of generation, transmission and distribution and vary among provinces.

Recent US experience with highly volatile energy prices did not necessarily translate in similar fluctuations in Canada, but affected positively the export prices for provinces such as British Columbia. While the wholesale export prices had been around $40 per MWh for a long time, they rose up to $110 per MWh in 2001 during the California crisis.

Retail electricity prices in Canada are among the lowest in IEA countries (an indication is provided in Table 21).

**Table 21**

**Indicative Average Electricity Prices, 2002**

(US$ cents/kWh)

| *Country* | *Industry* | *Household* |
|---|---|---|
| Canada | 2.0-4.5 | 3.8-7.2 |
| France | 3.7 | 10.5 |
| United Kingdom | 5.2 | 10.5 |
| United States | 4.6 | 8.4 |

Source: IEA, *Energy Prices and Taxes*, Second Quarter 2003; Hydro Québec, 2002, *Comparison of Electricity Prices in Major North American Cities*, *Rates effective on May 2002*, Montréal.

# NUCLEAR

The federal government is supportive of the nuclear energy option for Canada and views nuclear energy as an important component of a diversified energy mix. The government also recognises that nuclear can play an important role to help Canada meet its objectives for climate change mitigation.

Nuclear policy falls within the jurisdiction of the federal government. Natural Resources Canada (NRCan) develops and implements policy and provides information and advice on supporting the institutional, legislative and financial framework for the nuclear industry. Two organisations report through the Minister of Natural Resources Canada to Parliament.

- Atomic Energy of Canada Limited (AECL) is a Crown corporation owned by the government of Canada. It is responsible for the design, marketing, construction and servicing of CANDU power reactors, the only technological variant deployed for generating electricity in Canada.

- The Canadian Nuclear Safety Commission (CNSC) is the federal agency responsible for regulating the health, safety, security and environmental aspects of all nuclear activities in Canada. The CNSC supersedes the former Atomic Energy Control Board (AECB). The transition was established by the Nuclear Safety and Control Act in 2000.

The regulations made by CNSC concerning the development, production and use of nuclear energy are subject to approval by the Governor in Council who appoints the members of the commission and designates one of them as its president.

The CNSC works in conjunction with the relevant bodies of the localities and provinces within which nuclear activities are conducted.

# *NUCLEAR ELECTRICITY GENERATION*

## Nuclear Reactors

Nuclear energy is an important component of Canada's energy mix. Twenty-two reactors are deployed in three provinces, Ontario (20), Québec (1) and New Brunswick (1). Nuclear generation in Canada was 70.2 TWh in 2002, accounting for 12.1% of the total. The 22 nuclear power reactors are operated by three public utilities and one private company, Bruce Power. The units at Bruce A and B have been leased from Ontario Power Generation Inc. (OPG) to Bruce Power, a consortium currently comprising Cameco Corporation (31.6%), TransCanada Pipelines (31.6%), Ontario Municipal Employees Retirement System (31.6%) and The Power Workers Union and The Society of Energy Professionals (5.2%). OPG operates the other twelve reactors in Ontario (Pickering A and B, Darlington). Of the total 22 reactors, 17 are currently in full commercial operation.

**Table 22**

**Canada's CANDU Reactors**

| *Reactor* | *Province* | *MWe* | *In service date* | *Operator* |
|---|---|---|---|---|
| Pickering A | Ontario | 4 × 515 | 1971-73 | OPG |
| Bruce A | Ontario | 4 × 769 | 1977-79 | Bruce Power |
| Point Lepreau | New Brunswick | 1 × 635 | 1983 | NB Power |
| Pickering B | Ontario | 4 × 516 | 1983-86 | OPG |
| Gentilly 2* | Québec | 1 × 638 | 1983 | Hydro Québec |
| Bruce B | Ontario | 4 × 860 | 1984-87 | Bruce Power |
| Darlington | Ontario | 4 × 881 | 1990-93 | OPG |

*: Gentilly 1 was shut down in 1979.

Source: NRCan.

## Performance and Refurbishment

The average plant load factor of nuclear reactors in Canada is significantly lower than the OECD average. The Nuclear Energy Agency's published data for 2002 show an average plant load factor in Canada of 77.8%, excluding the Ontario off-line plants[29]. Including the off-line plants would bring this down by about 20%. A similar figure for the US was 90.2%.

The government of Canada is foreseeing an increase in future years to 97-109 TWh (from 70.2 TWh in 2002), provided that all the refurbishment work foreseen goes ahead.

### *Ontario*

The two nuclear operators in Ontario, OPG and Bruce Power, are pursuing their respective recovery plan to restart 5 of the 8 laid-up units at the Pickering A and Bruce A stations.

In Ontario, the newer plant at Bruce B is currently performing satisfactorily. However, the operational performance of the older plants at Bruce A and at Pickering A have been seriously affected by some maintenance and management problems of the utility. The entire Bruce A plant was shut in 1997, along with the Pickering A power plant within the framework of the Nuclear Asset Optimisation Program by Ontario Hydro (later OPG). Attention was focused on maintaining the safe and efficient operation of the twelve newer units.

In late 2003, after a refurbishment programme costing $550 million, two of the Bruce A units, Units 3 and 4, have been successfully returned to service. In January 2004, Bruce Power announced that it will examine: the feasibility of restarting Bruce A, Units 1 and 2; the preliminary case to refurbish its four Bruce B reactors; and the feasibility of building one or more new reactors at the Bruce site.

OPG has worked to re-instate the four units at Pickering A, of which only one had been returned to service at the end of 2003. Considerable escalation of the costs of the refurbishment project was experienced relative to the initial estimates on which the decision to proceed had been based. A provincial committee, led by former federal energy minister Mr. Jake Epp, has been set up to assess the management of the return to service project at Pickering A (see box). Another committee, chaired by Mr. John Manley, a former federal finance minister, is currently working to determine whether to complete refurbishing the other three units of Pickering A that are yet to return to service.

29. The average capacity factor of the eight CANDU-6 currently operating abroad is 90%.

Pickering A plant was partially refurbished (including retubing) in the 1980s, when one of the units was shut for five years. The total cost of that refurbishment was approximately $1 billion.

## Major Findings of the Pickering Review Panel and the Manley Report

A panel headed by former federal energy minister Jake Epp was asked to investigate the problems with the Pickering A refurbishment. In the report issued in December 2003, the panel found that, compared with the plan approved by the Board of Directors of Ontario Power Generation Inc. (OPG) in August 1999, the return to service cost for Unit 4 had almost tripled, and this date had slipped by more than two years. In particular, the panel found that:

- The cost of refurbishment of Unit 4, which returned to service in late 2003, was $1.25 billion, against the first definitive estimate of $457 million. It also took more than twice as long as the original estimate to complete the refurbishment.
- The cost estimate for fixing the remaining plants is $3 to 4 billion with a return to service in the period 2006-2008. This compares with the first definitive estimate of $1.1 billion, assuming that all units would return to service by the end of 2002.

Several problems are identified.

- From the outset, OPG failed to recognise the full scope and complexity of the projects and was too slow to put in place the appropriate project management and accountability mechanisms.
- Management of the project from initial planning to execution was seriously flawed. Well-established industry practices and steps for carrying out a project of this size and complexity were not followed.
- Because adequate cost and progress reporting systems were not put in place, projections of project costs and completion dates were consistently unreliable and unrealistic.
- Given the size of the investment and the importance of the project, the Ontario government and the OPG should have exercised greater oversight of the project's economics and execution, and been quicker to respond to emerging problems.

For the long-term success of the OPG, regardless of which decision is made about the remaining Pickering units, OPG must ensure the improvements in corporate governance, project management and management effectiveness and company culture.

The report concludes..."These facts are alarming, but they are not the only price paid. The delay in the return to service of Pickering A has adversely affected Ontario's electricity sector and pushed up prices for residential and business consumers. The costs and delays of the project have also reduced OPG's revenues, capital resources and corporate value. But perhaps most seriously, faith has been compromised in the affordability and certainty of the supply of electricity vital to Ontario's citizens and businesses."

The implications of the problems at Pickering led to a follow-up report which analysed the situation of OPG, in particular to provide recommendations on whether or not to restart units that were shut down at the Pickering plant. This report was prepared by John Manley, a former finance minister, and was released in March 2004. The report concluded that refurbishing the first generation of reactors is the most cost-effective option based on a detailed cost analysis, but the report also called the board of OPG to wait until there is clear evidence of success on the Unit 1 Project before proceeding with any further development work on Unit 2 or 3.

The report is favourable to the use of nuclear energy for Ontario, but it calls for more learning from experiences in nuclear plant management and for a nuclear strategy driven by what is best for Ontario's electricity sector only, independent from a broader industrial development strategy for the domestic nuclear industry. Similarly, the report asks Ontario not to be biased towards using Canadian-developed technology, but to seek out the best available technology worldwide.

The Ontario government is currently reviewing these two reports.

Source: Report of the Pickering Review Panel, December 2003.

### *Québec and New Brunswick*

The CANDU-6 units in Québec and New Brunswick are operating satisfactorily but refurbishment would be necessary to extend their operating lives, which is an inherent feature of the CANDU design. During 2001-2002, Point Lepreau operated with a capacity factor of 82.5%, its second-highest performance in six years. Since 1983, the station's in-service capacity factor has averaged 82%. The lifetime average performance of the Gentilly 2 station has been similar.

Both units are approaching the age when a decision will need to be taken on refurbishment. In New Brunswick, the Public Utilities Board recommended to the NB Power Board of Directors in September 2002 not to proceed with the refurbishment of Point Lepreau due to the lack of economic advantage. NB Power and Atomic Energy of Canada Limited (AECL) have conducted an assessment and are awaiting a government decision. Following the assessment, the costs and benefits of refurbishment will be compared with other development opportunities to determine the most viable option for NB Power. Concurrently, the New Brunswick government is exploring the potential for private-sector involvement in the project, should it proceed. Current plans are for the refurbishment project to commence in 2008.

Similarly, Hydro-Québec is currently conducting studies and public consultations on the refurbishment issue. A decision by the Board of Directors of Hydro-Québec is expected in 2006. In the statement submitted by Hydro-Québec to the Québec electricity regulator in February 2004, Hydro-Québec noted that the decision to refurbish the plant would depend on the results of the cost evaluation, obtaining necessary government approval and an evaluation of the federal government decision on nuclear fuel waste disposal, not expected before the autumn of 2005. If the decision is made to proceed, Hydro Québec estimated that refurbishment would begin in 2010 and last at least 18 months. The statement stressed the need of caution in terms of cost projections based on the recent experiences of large-scale refurbishment projects in Canada.

## International Canadian Nuclear Implementation

The Canadian CANDU reactor operation is complemented by eight units in the Republic of Korea, Argentina, China and Romania. An additional unit is under construction in Romania.

Table 23

**CANDU Reactors outside Canada**

| *Reactor* | *Country* | *MWe (net)* | *Year in service* |
|---|---|---|---|
| Wolsong 1 | South Korea | 1 × 629 | 1983 |
| Wolsong 2 | South Korea | 1 × 629 | 1997 |
| Wolsong 3 | South Korea | 1 × 629 | 1998 |
| Wolsong 4 | South Korea | 1× 629 | 1999 |
| Embalse | Argentina | 1 × 600 | 1984 |
| Qinshan 1 | China | 1 × 665 | 2002 |
| Qinshan 2 | China | 1 × 665 | 2003 |
| Cernavoda 1 | Romania | 1 × 629 | 1996 |
| Cernavoda 2 | Romania | 1 × 629 | 2006 |

Source: NRCan.

All Canadian plants share technical knowledge and experience by their owners' membership in the CANDU Owners' Group Inc. (COG).

### Future Nuclear Power Plants in Canada

The government of Canada continues to be supportive of the development of CANDU technology for future deployment. In September 2003, AECL was provided with $46 million in addition to its established budget of $100 million to support its development of the Advanced CANDU Reactor (ACR). At the end of the year, AECL proposed a plan to construct four pairs of ACRs at a total cost of $12 billion to a special task force which will report to the minister of natural resources in due course.

Additionally, Canada is an active participant in the Generation IV International Forum (GIF), an initiative seeking to identify and develop nuclear systems for deployment in the longer term, *i.e.* 2020 and beyond. Canada is involved in the development activity of the Super Critical Water-Cooled Reactor.

### Nuclear Third-party Liability

The Nuclear Liability Act 1976 establishes a regime to compensate third parties for damage suffered as a result of a nuclear accident occurring in Canada. Whilst its principles remain valid for today, the act is currently being revised, in particular to increase the limit of the plant operators' liability from the current level of $75 million.

## NUCLEAR FUEL CYCLE

### Uranium

Canada is the largest producer of uranium in the world, with 10 000 tonnes of uranium (tU) in 2003. Mining and milling is conducted by private-sector interests, the largest of which are Cameco Corporation and Cogéma Resources Inc. All production activity is centred on deposits and facilities in the Athabasca Basin in northern Saskatchewan.

Table 24

**Canadian Uranium Resources in the Athabasca Basin** (tU)

| | |
|---|---|
| Key Lake/McArthur River | 175 000 |
| McClean Lake | 10 000 |
| Rabbit Lake | 6 900 |
| Cigar Lake | 89 000 |
| Midwest | 13 800 |

Source: NRCan.

The McArthur River ore body is the largest high-grade uranium deposit discovered in the world with more than 175 000 tU at an average grade of over 20% uranium (U).

Figure 27

**Uranium Production Centres**


Source: NRCan.

Canada's total known uranium resources, recoverable at a cost of US$ 80/kgU or less are estimated to be about 439 000 tU, the third-largest in the world after Australia (873 000 tU) and Kazakhstan (729 000 tU).

### Nuclear Fuel Fabrication

Canada is also a major producer of conversion services supplying the international market. This activity is based on Cameco Corporation plants in Port Hope and Blind River, Ontario.

CANDU fuel fabrication is conducted in Canada by General Electric Canada Inc. and Zircatec Precision Industries Inc.

### Nuclear Waste

Canada has not yet selected an approach for the long-term management of its nuclear fuel waste and there is no pressing technical constraint to ongoing storage. However, the Nuclear Fuel Waste Act (NFWA) 2002 sets out the process for selecting and implementing a long-term management solution. The principal responsible body is the Nuclear Waste Management Organisation (NWMO) which has already been constituted by the nuclear utilities. It is due to report to the federal government by 15 November 2005 with its recommendations on the approach to be pursued. Specifically, consideration must be given to deep geological disposal, indefinite storage at reactor sites and centralised storage.

Additionally, the NFWA has required waste producers, such as nuclear plant operators and AECL, to set up and make regular contributions to trust funds to pay for the total costs of implementing the approach to long-term management of wastes which will be selected.

All irradiated CANDU fuel is currently stored at the power plant sites with there being no immediate concern about the availability of capacity to meet operational needs.

### *Nuclear Research and Development*

Research and development on the CANDU reactor system is conducted by AECL, principally at its Chalk River Laboratories. The funding of programmes is approved by the federal government.

# CRITIQUE

## ELECTRICITY

Electricity in Canada is under provincial jurisdiction except inter-provincial trade and international trade with the US. Nevertheless, the federal government has important policy roles to contribute to maintaining and improving the overall competitiveness of the Canadian electricity industry and, hence, the Canadian economy as a whole. Greater international and inter-provincial co-operation on electricity would enhance its reliability and security.

One of the possible roles for the federal government is the growing interconnection between Canadian and US electricity markets. The proximity of populated areas in Canada to the US border is a reason why there is traditionally more electricity trade with the US than between Canadian provinces. The grid failure of 14 August 2003, which started in Ohio, but had a cascading effect in Canada, demonstrates the need for more co-ordination and joint actions between the federal government, the provinces and their US counterparts. Also the regulations and the development of market design by FERC have major impacts on the policy and regulation of electricity grids and markets in Canada through FERC's control of access of Canadian utilities to the US market. Capital for investment in the electricity infrastructure in Canada is competing with the US market.

Because of such a strong link between the two markets, the issue of reliability of electricity supply to final customers in Canada has to be seen in the context of the overall North American electricity market. It would be advisable to enforce reliability standards in the Canadian electricity systems compatible with those in the US. Information flow on the status and operation of the grid is also an issue that has to be closely co-ordinated within North America. Adequate information and governance structures are necessary to reduce the likelihood of cascade effects of local problems in the North American grid to spread. As grids in North America are getting more interdependent owing to increased cross-border trade promoted by the reform of electricity markets in North America, the path of development of the regulatory framework for the electricity markets should not only be consistent within Canada but also compatible with the development of market reform in the US.

Another important issue related to the previous one is the development of a Canadian domestic electricity market. While some progress has been made on electricity market reform that opened access to transmission grids and facilitated the development of inter-provincial power flows, the progress has been uneven between provinces. Beyond the geographical challenges, the creation of a larger Canadian market faces difficulties related to the lack of an inter-provincial transmission infrastructure. It is interesting to note that there are fewer inter-provincial high-voltage transmission links (380 kV and beyond) between Canadian provinces than between some provinces and their US neighbouring states. While an east-west continuous high-voltage link has yet to be proven economic, a larger integration of power markets beyond existing provincial boundaries is worth investigating. This could enable a more diversified electricity supply mix and also facilitate more development of the large low-GHG-emitting hydro resources. When limited to provincial boundaries, the supply-demand balance assessment cannot lead to cost-effective investment decisions. The federal authorities have to play their role to avoid this difficulty. The debate on instruments to promote the benefits of increased linkages between provincial electricity markets is still in its infancy but would deserve being supported. Ways to streamline the processes for authorising inter-provincial transmission lines as well as across the Canadian-US border would also need to be found.

The two issues described above would require the federal government to play an active role in close co-operation with provincial governments. The development of inter-provincial and international trade could be an important factor in bringing new entrants to provincial markets and ensuring that effective competition develops within provincial and regional markets. The broad policy objectives that the federal government might set would be to encourage the development of regional markets, involving several provinces and the US market. Such a role would ensure that the benefits of competition are brought directly to Canadians, as well as indirectly through encouraging a growing trade with the US. Federal and provincial governments have been co-operating in the areas involving inter-provincial and international electricity trade issues in a forum such as the federal-provincial energy ministers meeting. Such efforts should be further strengthened.

Provinces have jurisdiction over electricity markets and have the lead role in market reform. They generally consider reform of the electricity sector as necessary and are addressing the issues. However, progress in the electricity market reform differs among provinces, according to the specific circumstances in the province such as the potential for competition, potential stranded assets and interconnections with other jurisdictions. Alberta and Ontario introduced retail competition and Québec, Manitoba and British Columbia introduced wholesale competition, while other provinces and territories continue to be supplied by one utility. In some provinces, market reforms are driven by the US regulatory changes to enable the provinces' players to be part of the US market. While this is a natural development, it could also result in very different market structures among the provinces reflecting their individual counterparts in the US. Respecting the principal role of the provincial governments in the market reform, the federal government might wish to keep this as coherent as possible within Canada. In this context, it would be advisable to pursue the consultation process for progressing further in the reforms of the electricity sector as an opportunity to contribute to Canada's goals in terms of economic growth and sustainability, and to the provinces' goals in terms of new investments in the electricity sector.

The measures taken in Alberta and Ontario to cope with electricity price hikes provide useful insights, in particular in terms of price volatility, investment and government intervention. The Ontario government capped retail prices for about half of the market at a price well below the cost of power and the entry cost of new plants (in the range of $55-60/MWh). These steps had a number of important short-term consequences: market prices remained high and the government is now responsible for subsidising the prices paid for electricity. These subsidies cost $550 million during the first 12 months of the operation of the market. The government's action has also had an effect on electricity demand. Consumers covered by the price cap have less incentive to conserve electricity. This in turn has raised demand and the market price for electricity. It has also increased costs to the government (who must take the spot price) and to those large consumers that had chosen to remain exposed to the spot price. The continuing rise in demand has led the government to contract for an additional 270 MW of peak generating capacity to act as additional operating reserve. The high wholesale prices should begin to fall as capacity under construction at the time of the crisis is completed. However, no new projects have been proposed by the private sector since the government announced its shift in policy. The market operator has suggested the market will be short of peak capacity as early as 2005. While the wholesale market remains open and able to set prices freely, investors are more reluctant to move into the Ontario market because of high political risks. As a consequence, prices in the wholesale market have to move even higher before new investments will occur. This leads to higher government subsidies and to increased risks of power shortages, which in turn leads to direct government intervention to add peaking capacity. Thus, the government finds itself paying for higher prices and for new supply. Concerned about the impact on the province's finances, the new government is reviewing the cap.

Alberta's response was different. Opening of the retail electricity market in Alberta in 2001 happened at a time of volatile wholesale prices. To cope with this situation, the government established a retail price cap on electricity. However, unlike Ontario, the price cap was set at a relatively high level to preserve the signal for new investments. Thanks to this, investment in new generating capacity, which had been keeping pace with growth in peak load, is continuing. Nevertheless, Alberta's government recently announced that it would delay removing the capped retail prices until 2006 and generally the retailers have problems making a profit with small consumers.

From the examples of Ontario and Alberta, a lesson can be drawn that protection of consumers against high prices must be carefully designed to avoid disruption of the market. Intervention by governments in the electricity markets threatens to disrupt the market mechanisms and to discourage investment. In particular, price capping should be set at sufficiently high levels and should be transitional until a more competitive market can be established. While the provincial governments have the principal authority on these issues, a more active role by the federal government may be required. Recent experiences in Alberta and Ontario could be shared in a federal and provincial co-operation process, and a consensus on effective mechanisms to enable measures to mitigate the price volatility for household consumers should be explored, especially for the ones that do not want to participate in the electricity market.

The very high price volatility experienced in electricity markets is a direct consequence of the very low demand-price elasticity of electricity consumption, especially by small consumers. There is considerable evidence that this elasticity is lower than it needs be owing to the lack of ability and incentives for demand to respond to price. Enhancing demand response will reduce the extreme price experienced during tight supply, in effect, by spreading the price peaks over a large number of hours. So far, demand-side response from household electricity consumers has been limited as regulated retail prices are not always reflecting the supply conditions. While this depends on provincial decisions, there might be a role for the federal government to foster the formulation and implementation of demand-side response mechanisms across the provinces.

## NUCLEAR

Canada's nuclear power programme is at a critical point in its history. While newer plants are performing well, some of the older plants are experiencing problems in their refurbishment. At Pickering A, while one refurbished reactor is now on line, three other units remain laid up for six years, after less than a decade from their rehabilitation in the 1980s (including the replacement of the pressure tubes in the reactor core, technically known in Canada as "retubing"). At the Bruce site, while two reactors have been restarted with fewer problems than Pickering A, two other reactors are undergoing a feasibility study to determine refurbishment costs in detail before proceeding to a decision.

The economic and financial viability of refurbishing any nuclear power plant depends on specific factors such as the anticipated cost of the refurbishment, the anticipated price of electricity in the electricity market, the expected performance of the plant once it is refurbished and the regulatory environment. An official review carried out in 2003 shows that the cost for Pickering A Unit 4's return to service in 2003 almost tripled compared with initial cost assessments, and the return to service date had slipped by more than two years. The Manley Report mentioned earlier has concluded that refurbishing the first generation of reactors is the most cost-effective option. The report committed support for refurbishing only one more reactor and called for delaying a decision on the remaining two, pending the outcome of the work. The report also recommended using the best nuclear technologies, regardless of national origin.

The Pickering Review Report mentioned earlier has identified many problems related to project management, adequate cost and progress reporting, projections of project costs and completion dates, and provides valuable lessons for other CANDU reactors. It should be recognised that the return of the other three units remains a large, complex project with a corresponding cost involving the reconditioning, rebuilding, replacing or adding of new equipment at a 30-year-old station. Retubing is an inherent characteristic of CANDU technology if the operating lives of the plants are to continue beyond 25 years, and experience shows that in some cases this has been needed after only 10-15 years.

Canada should not forgo potentially attractive nuclear generation and the federal government should explore barriers to the attainment of maximum economic generation from the existing plants and help overcome the obstacles, consistent with safety considerations. Given the practical experience of the success of Bruce Power in managing the plants on the Bruce A site, it would be appropriate to consider promoting more competition in CANDU plant operation and refurbishment.

Canada has a wide range of energy sources at its disposal for the generation of electricity. Nuclear generation has been most viable in regions in which access to hydro and fossil energy supplies have been most difficult and costly. It seems appropriate for the federal government to facilitate the evaluation of the costs and benefits of deploying new nuclear plants in the future, in particular with regard to the environment and the benefit of further diversification of power generation in Canada.

There are economies of scale associated with significant new reactor construction projects. However, in Canada, the scope of building new nuclear reactors may be limited and, as a result, economies of scale may be difficult to achieve. Canada does have ambitions to continue to deploy CANDU technology in other countries, including the US. Nevertheless, the federal government should keep under critical review the potential for the deployment of ACR. Business studies and assessments of the relative merits of different technologies available in the world to assist the decision-making of Canadian utilities are essential.

Evidently, the strategic potential of nuclear energy in Canada in economic, environmental and security terms is such that Canada should maintain the option for its future deployment. In particular, its involvement in the Generation IV International Forum should continue to be supported.

Social concerns and a responsible government dictate that the optimum means of managing irradiated fuel in Canada should be identified and pursued. The federal government's plans and intentions in this area should be continued.

The limit of nuclear third-party liability to $75 million in Canada is low by comparison to other western, developed countries and 93% lower than the new minimum limit specified by the Paris Convention on Third Party Liability in the field of nuclear energy. It is appropriate that the government of Canada reviews and modernises the current legislation on this issue.

## RECOMMENDATIONS

*The government of Canada should:*

### Electricity

- *Work together with the provinces to ensure reliability of electricity supply, addressing the implications of increased physical and trade links with the US and the effects of ongoing market reform on grid design, operation and information flow between North American system operators and between other market participants.*

- *Analyse, in collaboration with the provinces, the costs/benefits of increased electricity links between different Canadian provinces with regard to improving reliability of electricity supply and creating larger electricity markets. Analyse what instruments would best promote such benefits.*

- *Set up a process of consultation with the provincial administrations and regulators, and the electricity supply industry to promote a consensus on the further advancement of electricity market reform compatible with US and Canadian electricity market developments. Co-ordinate with other policy objectives, such as environmental and industrial objectives, in order to ensure timely investment in new generating capacity.*

- *Foster the simplification of regulatory processes required for the authorisation of new power capacity and power lines.*

- *Address ways to improve demand-side response by all market participants. Analyse the effects of market opening on household consumers and find ways to protect households from electricity price volatility for those who do not wish to participate in the market.*

### Nuclear

- *Explore barriers for the attainment of maximum economic generation from existing nuclear plants, including the return of plants currently shut down, consistent with safety considerations. To this end, consider promoting more competition in CANDU plant operation and refurbishment.*

- *Evaluate the costs and benefits of adding new nuclear capacity with particular regard to the environment and diversification of power generation.*

- *Maintain under critical review the potential for the deployment of ACR.*

- *Maintain the option to deploy nuclear power plants in the future, irrespective of the success of AECL in marketing ACR.*

- *Continue plans and intentions to identify and pursue the optimum means for the long-term management of irradiated CANDU fuel in Canada.*

- *Increase third-party liability of nuclear operators to reflect the kind of liabilities already established in other developed Western countries.*

# ENERGY RESEARCH AND DEVELOPMENT



## OVERVIEW

The main target of Canadian energy R&D is the provision of a safe, reliable and secure supply of energy through technologies and systems for the production and use of energy that respects the environment and is sustainable for future generations, in particular by reducing GHG emissions.

Public funds are provided by federal programmes as well as at the provincial level. Because of the government's interest for practical solutions and economic applications, privately initiated R&D activities are encouraged, partly in public partnership.

Federal energy R&D is planned and conducted with energy policy guidance from NRCan, strategic directions from the Interdepartmental Panel on Energy R&D and external advice from the National Advisory Board on Energy Science and Technology (NABEST) at the overall programme level. A number of other advisory committees provide comments on the directions of the various technological areas.

The federal government funds energy R&D mainly through the following ways:

- The Program of Energy Research and Development (PERD).
- R&D tax credits which apply to all R&D, including energy.
- R&D funding included in climate change mitigation policies.

Some other federal government programmes not focused on energy may fund some energy-related research projects. The major ones are: Industry Research Assistance Program (IRAP) of the National Research Council; the Technology Partnerships Program (TPC) of Industry Canada; Climate Change Technology Early Action Measures (TEAM) and the Atlantic Innovation Fund (AIF) of the Atlantic Canada Opportunities Agency (ACOA). The Natural Sciences and Engineering Research Council (NSERC) also supports some energy R&D, mostly basic and applied research.

Canada's research activities are well integrated in international collaborations on a bilateral level, for example with the US, but also in international programmes such as the IEA R&D efforts. Canada participates in 31 of the 41 IEA Implementing Agreements, very often in co-ordinating functions. Canada benefits from a high reputation for good co-ordination and communication within the national energy R&D community concerning Implementing Agreements.

In the budget for 2003-4, Canadian public investment in energy R&D is split almost equally between energy conservation (22%), fossil fuels (20%), nuclear (20%) and other cross-cutting research or technology development (19%). Renewables and power storage technologies absorb 13% and 7% respectively. Compared with 2000-1 estimates, the share of R&D for nuclear energy has been decreasing (from 37% in 2000-1 to 20% in 2003-4) and more efforts are put on energy conservation (from 19% in 2000-1 to 22% in 2003-4) and renewables (from 5% in 2000-1 to 13% in 2003-4), in line with the strengthening of climate change mitigation policies.

Table 25

**Estimated Government Energy R&D Expenditures, 2003-4**

($ million)

| *Activities* | *Federal government* | *Provinces* | *Total* | *%* |
|---|---|---|---|---|
| Conservation | 67.2 | 6.3 | 73.4 | 22 |
| Fossil fuels: oil, gas and coal | 53.3 | 12.4 | 65.7 | 20 |
| Renewable energy sources | 34.8 | 7.2 | 42.0 | 13 |
| Nuclear fission and fusion | 63.9 | 2.4 | 66.3 | 20 |
| Power and storage technologies | 15.6 | 9.6 | 25.1 | 7 |
| Other cross-cutting R&D | 54.3 | 8.8 | 63.1 | 19 |
| **Total** | **289.1** | **46.6** | **335.6** | **100** |

Source: NRCan.

Total public expenditures for R&D grew significantly between 2000 and 2003. With 0.03% of GDP in 2002, Canada’s public effort on energy R&D is high by international standards, on a par with that spent by other IEA countries such as France, Norway or the United States.

## *PROGRAM OF ENERGY RESEARCH AND DEVELOPMENT*

PERD is primarily an applied research and technology development programme. It is implemented by NRCan’s three dedicated energy research laboratories, CANMET Energy Technology Centers (CETC-Ottawa, CETC-Devon and CETC-Varennes), which receive about 60% of their budget from PERD, and other federal departments and agencies with energy-related capabilities and activities.

PERD funds research in universities and in the private sector through joint projects, grants and consortia. The trend over the past decade has been to move to multi-party consortia as in the case of the National Center for Upgrading Technology (NCUT), Canadian Oil Sands Network for Research and Development (CONRAD), Petroleum Technology Alliance Canada (PTAC), Petroleum Technology Research Center (PTRC) or NRCan Institute for Fuel Cell Innovation. There are other federal laboratories which carry out some energy-related R&D as part of their portfolio, although they are not dedicated to energy.

Overall guidance on PERD is provided to NRCan by the Panel on Energy Research and Development. The panel members are assistant deputy ministers and senior officials from the federal R&D departments and agencies which perform or manage energy R&D and which have a policy interest in science and technology (except for nuclear fission). This panel is responsible for bringing industrial, environmental and science policies to bear on energy R&D policy and strategic direction, and for setting PERD's strategy and priorities. This panel reports to the deputy minister of Natural Resources Canada. Participation in PERD is effected through a memorandum of understanding signed by all the participating departments and agencies.

The PERD program is interdepartmentally delivered through the following 12 departments and agencies, supporting NRCan's energy policies by a combination of departmental and PERD funds:

- Agriculture and Agri-Food Canada
- Canada Mortgage and Housing Corporation
- Environment Canada
- Fisheries and Oceans Canada
- Health Canada
- Indian and Northern Affairs Canada
- Industry Canada
- National Defence
- National Research Council Canada (Biotechnology Research Institute, Canadian Hydraulics Center, Industrial Materials Institute, Institute for Aerospace Research, Institute for Chemical Process and Environmental Technology, Institute for Ocean Technology, Institute for Research in Construction, Integrated Manufacturing Technologies Institute, Regional Innovation Center – Ottawa)
- Natural Resources Canada (Canadian Forest Service, CANMET Energy Technology Center, CANMET Mineral Technology Branch, Earth Sciences Sector)
- Public Works and Government Services Canada
- Transport Canada

The Office of Energy Research and Development of NRCan administers PERD's annual budget of $57.6 million (2003). Funding for PERD has remained stable in nominal terms and thus is declining in real terms. Since 1999, NRCan has used a results-based management system to manage PERD's investments. Such a system incorporates performance measurement and reporting of the work conducted with PERD funds. It also uses impact evaluation to assess performance in meeting objectives and inform decisions about resource allocation, including third-party advice and review, to ensure that such decisions are unbiased and reflect energy R&D and policy needs.

Although PERD covers a broad spectrum of activities in the field of energy R&D, it is mainly focused on six non-nuclear strategies chosen to address the government of Canada's energy priorities. Along those lines, PERD is further divided into 37 "Programs at the Objective Level" (POL), managed independently from each other. Each POL has a POL committee and a community around it, including all stakeholders (universities, industry and governments) and relevant Implementing Agreements of the IEA.

The linkage between basic science and energy technology development is not done at the overall PERD level, but at individual POL. Basic energy-related research in Canada is primarily done by universities, with a lesser amount done by NRCan's and the National Research Council's (NRC) laboratories. However, there are examples of recent activities elaborating, for example, on future perspectives of advanced biotechnical approaches applied to improve energy-efficient industrial processes. Further basic science activities on nanotechnologies, conducted under the auspices of the National Research Council of Canada, with special regard to energy technologies, are also under investigation.

Since the 2000 review of Canada, the restructuring of PERD has been completed to improve its efficiency, increase its focus on long-term activities and adapt to the need of climate change mitigation policies. Changes involved consolidating the R&D programmes and applying new evaluation methods. The following changes have been made: the POLs related to hydrogen – *i.e.* hydrogen and fuel cells have been consolidated into a Hydrogen Energy Economy POL; the POLs related to biomass, bioenergy and bioprocesses have been consolidated into a Bio-based Energy Systems and Technologies (BEST) POL; and the POLs related to industry end-use – Process Integration, Sensors and Controls, Separation and Drying, Combustion and Heat Pumps and Refrigeration – have been consolidated into a Highly Energy-efficient Industrial Systems and Technologies (HEIST) POL and Energy Management for Sustainable Communities. Since the government reviews annually one-fourth of PERD's programme objectives to complete a full cycle in four years by the end of 2003, half the PERD had been reviewed since it was restructured.

## PERD Priorities

**Strategy 1: Diversifying Canada's Oil and Gas**

- offshore and northern oil and gas
- oil sands and heavy oil
- environmental and safety issues (flares, pipeline integrity, and groundwater and soil remediation)

**Strategy 2: Cleaner Transportation for the Future**

- improved urban air quality, including reduced emissions and greenhouse gas production
- transportation fuels from renewable energy sources
- improved vehicle and transportation system efficiency
- fuel cells, electric and hybrid vehicle components

**Strategy 3: Energy-efficient Buildings and Communities**

- building research and development
- waste recovery and utilisation
- integration of energy efficiency and renewable energy technologies
- improvements in sustainable development of communities
- district heating and cooling

**Strategy 4: Energy-efficient Industry**

- innovative products, processes or systems for improved energy efficiency by industry
- heat management
- process integration
- primary agricultural production
- fisheries
- forestry
- mining and metals
- agricultural and forestry biomass
- sensors and controls, separation technologies, combustion and bioprocesses

**Strategy 5: Canada's Electricity Infrastructure**

- clean and efficient combustion technologies for large utility electricity generation
- efficient conversion of renewable and non-renewable energy to electricity
- $CO_2$ capture and storage

**Strategy 6: Climate Change**

- support for Canadian energy sector's response to impacts of climate change
- enhanced natural uptake of greenhouse gas

Source: NRCan.

## NUCLEAR R&D

Public nuclear R&D is carried out by AECL, a federal Crown corporation owned and controlled by the federal government. AECL is a global nuclear technology and engineering company that designed and developed the CANDU nuclear power reactor, as well as other advanced energy products and services. It supports customers over the entire plant life cycle from R&D, nuclear services, design and engineering, to construction management, specialist technology, and waste management and decommissioning.

The nuclear R&D budget has traditionally been and continues to be administered separately from other energy R&D such as PERD.

NRCan and the Treasury Board ensure an alignment of nuclear R&D to government objectives and priorities and AECL manages the R&D programmes in consultations with other Canadian stakeholders.

## CLIMATE CHANGE MITIGATION R&D

The first climate change initiative of the federal government after signing the Kyoto Protocol was the Action Plan 2000 on Climate Change. It included a $20 million programme in science and technology which spans the innovation spectrum – discovery, research and development, deployment and marketing. It builds partnerships to plan and advance climate change R&D, lays the foundation for long-term technological advances and accelerates the development of cost-effective GHG mitigation technologies in multiple sectors. The federal government and university laboratories conduct high-risk R&D as well as applied R&D to advance promising technologies on a larger scale. Technology road-maps assess needs and market barriers. Technology networks and workshops facilitate information exchange and dissemination.

Following Canada's ratification of the Kyoto Protocol in November 2002, the federal government announced a $200 million investment in science and technology, building on existing activities, as part of the $1.7 billion budgeted in 2003 by the government to mitigate emissions. This investment is going to be disbursed over a five-year period (2003-4 to 2007-8). The specific R&D programmes are in Clean Fossil Fuels, Hydrogen, Advanced Energy Efficiency, Decentralized Energy Production and Biotechnology.

Sustainable Development Technology Canada (STDC) Foundation manages a fund for investment established by the government of Canada in 2001 through NRCan and Environment Canada, to further the development and demonstration of innovative technology solutions to reduce GHG emissions and improve air quality. SDTC's mandate is to act as the primary catalyst in building a sustainable development infrastructure in Canada. The Foundation operates as an arm's-length, non profit-making corporation with fifteen directors on its board. Initially the Foundation was given $100 million to allocate to eligible recipients over a five-year period. In 2003, the fund was accrued by $250 million as part of the new initiative to mitigate climate change in the 2003 budget. This initiative is dependent upon the formation of creative and economically sound partnerships from the private sector, academia, non-profit-making organisations. These partners will provide at least a further $200 million of leveraged funding as, on average, SDTC will fund up to 33% of an eligible project. There will be a 75% stacking limit for all forms of government funding on a per-project basis.

## PROVINCIAL GOVERNMENTS R&D

### ALBERTA

The Province of Alberta is the major funder of energy R&D through the Alberta Energy Research Institute (AERI), which replaced the Alberta Oil Sands Technology and Research Authority (AOSTRA). AERI's mandate is wider than that of AOSTRA. Its mission is achieved by promoting collaborative research, working with the Alberta Research Council (ARC), the province's departments of energy, environment, sustainable resource development and the federal government. AERI's focus is on clean coal, oil sands upgrading technologies, carbon dioxide management and sequestration, improved oil and gas production, and fuel cells and hydrogen.

AERI was created by the Alberta Science and Research Authority (ASRA). ASRA has announced the $22 million Alberta Science and Research Investments Program 2003 competition focusing on supporting projects that clearly align with the priority areas of energy, life sciences, and information and communications technology. The grants awarded under this programme will be used to leverage other funding sources, including the federal government and the private sector.

ARC is partially supported by the Alberta government. It develops and commercialises technologies in the energy, life sciences, agriculture, environment, forestry and manufacturing sectors. Energy is a significant part of its portfolio covering a wide range of oil and gas technologies and energy efficiency technologies.

### QUÉBEC

The Province of Québec supports energy R&D, primarily electricity (generation, transmission and end-use) research through Hydro-Québec. Strategic innovation complements the portfolios of innovation projects in generation, transmission, distribution and customer services.

Hydro-Québec developed a technological road-map for the company. It pointed to five areas as priorities: actively managing the network in real time to optimise commercial exchanges of energy, controlling the effects of climate change on run-off, demand and installations, improving the efficiency of the power system from generation to end-use, benefiting from decentralised generation and extending the limits of the transmission system.

The Province of Québec itself has no dedicated energy R&D programme but can support energy R&D projects under the Centre de Recherche Industrielle du Québec (CRIQ) and the Fonds Québécois de la Recherche sur la Nature et les Technologies.

A research unit of the Université du Québec, Trois-Rivières, the Hydrogen Research Institute (HRI), is the main research centre in Québec for hydrogen. The institute has conducted research on electrolysis, the storage of hydrogen and its safe use. It has also worked on several technological developments in the framework of the Euro-Québec Hydro-Hydrogène project, particularly on the demonstration of an urban bus running on a mixture of natural gas and hydrogen (Hythane®), and the production and testing of a hydrogen-adapted turbine. HRI is partially funded by PERD.

## ONTARIO

The Province of Ontario has no dedicated energy R&D programme but the Ministry of Energy, Science and Technology promotes innovation by investing in research through the Premier's Research Excellence Awards and the Ontario Research and Development Challenge Fund, both of which can support energy R&D.

The ministry contributes to innovation by strengthening links between basic research and the development of new technology and products through to commercialisation. The Ontario Centers of Excellence support technology development and transfer from research laboratories to industry. Of these, the Material and Manufacturing Center is the one most relevant to energy. It can support energy-related R&D such as chemical processing, intelligent controls, ceramics and concrete, metals and mineral processing, new materials, etc.

## SASKATCHEWAN

The Province of Saskatchewan supports oil sands, and heavy oils and oil and gas research through consortia such as the Petroleum Technology Research Center (PTRC), the Saskatchewan Research Council and through the Saskatchewan Petroleum Research Incentive, a royalty/tax credit of 15% of the costs of research projects undertaken at Saskatchewan research institutions.

PTRC is partially funded by PERD. It is a collaborative initiative of NRCan, Saskatchewan Industry and Resources (SIR), the University of Regina and the Saskatchewan Research Council.

The Saskatchewan Research Council (SRC) is a Saskatchewan government-owned organisation covering a number of fields of research of interest to the province, including energy. In energy its research focus is on heavy oil recovery, thermal enhanced oil recovery and horizontal wells' physical modelling and numerical simulation, gas/chemical flooding for a range of reservoirs and oil types. SRC also maintains a pipe flow technology centre studying pipe flow behaviour of two-phase and multiphase mixtures.

## BRITISH COLUMBIA (BC)

The main focus in BC is on fuel cells. The province is a recognised world leader in fuel cells and related technologies. The Premier's Technology Council, the body which advises the Premier on technology, is developing a strategy to build on this capability, working with Fuel Cells Canada. The Ministry of Competition, Science and Enterprise is charged with implementing the plan of the Premier's Technology Council.

Powertech Laboratories, a wholly-owned subsidiary of British Columbia Hydro (which is provincially-owned) also does energy research in areas such as hydrogen storage, or remote sensing of leaks from gas pipelines.

## MANITOBA

Manitoba Hydro, a provincial Crown corporation, is involved with over 100 research and development projects at any one time. Some are undertaken in-house while others support university and other research projects. Projects explore a wide range of topics, from improved system efficiency and reliability, to methods for remediating contaminated soils, to conserving burrowing owl habitat on transmission rights-of-way. Manitoba Hydro also does research on high-voltage direct current (DC).

# DEMONSTRATIONS, DISSEMINATION, MARKET DEPLOYMENT AND TECHNOLOGY TRANSFER

NRCan supports demonstrations, dissemination and market deployment, but in a limited way. There are no programmes specifically for demonstrations. The TEAM programme (Technology Early Action Measures) supports the demonstration of energy-related climate change technologies. Projects supported by the PERD programme have to ensure deployment plans.

The energy laboratories work closely with industry to demonstrate and transfer technologies developed by the laboratories. NRCan's energy research laboratories and other federal laboratories also perform research and cutting-edge technical services on a cost recovery basis for industry.

The Energy Technology Branch hosts and participates in several activities to disseminate information: workshops, seminars, trade shows, conferences, etc. NRCan's dedicated research laboratories also produce and disseminate technical publications. The Office of Energy Efficiency disseminates information on energy efficiency technologies, including from IEA's Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET).

Under the Action Plan 2000 on Climate Change, the Canadian International Technology Initiative develops technology transfer projects, facilitates market opportunities for climate change technologies by Canadian companies, analyses future international technology marketing activities and encourages partnerships with other countries to help reduce GHG emissions through clean development mechanism projects and joint implementation projects.

## CRITIQUE

Canada should be commended for the levels of effort made by the government to pursue energy R&D. Provincial R&D efforts are also commendable.

In the past, public R&D suffered from budget cuts. For example, the government R&D budget decreased from $271.6 million in 1991 to $168.5 million in 1999. Since then, the government R&D budget has been increasing. Although the budget of PERD remained flat between 2000 and 2003, the total R&D expenditures made by the federal government and the provinces increased. This is a positive development noting that R&D on technologies with mid- or long-term perspectives is strongly dependent on continuous programme conditions and stable infrastructures. This is also in line with the federal government's policy goals to make Canada a strong knowledge economy and to enable its primary energy resources to be used while mitigating environmental impacts of economic growth.

The expected R&D contribution to Canada's GHG emissions reduction made by the Climate Change Plan for Canada is quite ambitious, especially considering the time frame of the Kyoto Protocol. There is a common understanding amongst IEA countries that R&D policy is one of the key strategies for industrial economies to meet targets on global sustainability. However, the envisaged time frames are longer. The continuity of R&D funding will therefore be essential to Canada to reach its technology goals. In this regard, it is a positive development that the federal government has announced multi-year R&D investment programmes to curb GHG emissions following its ratification of the Kyoto Protocol.

The multiple funding programmes and the tax incentives for R&D provide a great variety of support to R&D activities, not only for traditional energy technologies but extending over related themes. In this way, a well diversified R&D community is supported and interesting multidisciplinary approaches envisaged. Federal programmes and tax incentives together with support activities on the provincial level allow issues of national, as well as regional, interest. Under the complexity of the Canadian funding structure, the federal government is allocating funding based on a comprehensive priority-setting process involving related departments as well as stakeholders from industry and science. This is commendable and such efforts should be further enhanced with stronger prioritisation. In doing so, special precautions have to be taken to maintain the necessary flexibility in the negotiation and assessment processes to react to unforeseeable occurrences, which might affect priorities in R&D.

Furthermore, diverse and partly overlapping funding programmes require appropriate transparency in decision-making processes supported by information exchange on activities and results. Great efforts have been made in this direction while restructuring the PERD. Such efforts need to be pursued and also to apply to all government-funded energy R&D.

Given the importance of energy for Canada, the role and usefulness of public energy R&D needs to be better publicised, especially within the government, to increase the value of existing R&D activities and reduce duplication of efforts.

## RECOMMENDATIONS

*The government of Canada should:*

- *If possible, avoid the kind of budget cuts in energy R&D that occurred in the late 1990s and maintain recent upward nominal trend.*
- *Increase further the profile of government R&D support by stronger prioritisation and concentration on a comprehensive view on key technologies.*

# ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

**SUPPLY**

| | | 1973 | 1990 | 2001 | 2002P | 2010 | 2020 | 2030 |
|---|---|---|---|---|---|---|---|---|
| **TOTAL PRODUCTION** | | **198.0** | **273.7** | **379.2** | **391.8** | **528.3** | **554.5** | **..** |
| Coal[1] | | 11.7 | 37.9 | 37.6 | 32.5 | 39.9 | 38.7 | .. |
| Oil | | 96.3 | 94.1 | 130.2 | 144.6 | 217.3 | 206.8 | .. |
| Gas | | 61.4 | 88.6 | 152.3 | 153.6 | 197.0 | 232.8 | .. |
| Comb. Renewables & Wastes[2] | | 7.8 | 8.1 | 10.5 | 11.3 | 17.0 | 19.0 | .. |
| Nuclear | | 4.1 | 19.4 | 20.0 | 19.7 | 23.4 | 22.1 | .. |
| Hydro | | 16.7 | 25.5 | 28.6 | 30.1 | 33.3 | 34.6 | .. |
| Geothermal | | – | – | – | – | 0.4 | 0.4 | .. |
| Solar/Wind/Other[3] | | – | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | .. |
| **TOTAL NET IMPORTS[4]** | | **–35.4** | **–60.6** | **–132.6** | **–137.7** | **–221.5** | **–204.3** | **..** |
| Coal[1] | Exports | 7.6 | 21.4 | 20.9 | 15.9 | 20.3 | 23.1 | .. |
| | Imports | 10.5 | 9.5 | 15.7 | 13.5 | 8.7 | 6.5 | .. |
| | Net Imports | 2.8 | –11.9 | –5.2 | –2.4 | –11.6 | –16.6 | .. |
| Oil | Exports | 63.1 | 49.7 | 96.0 | 101.2 | 174.4 | 158.5 | .. |
| | Imports | 48.8 | 34.5 | 57.0 | 53.7 | 54.2 | 60.0 | .. |
| | Bunkers | – | 0.9 | 1.0 | 0.9 | 0.7 | 0.8 | .. |
| | Net Imports | –14.3 | –16.1 | –40.0 | –48.4 | –121.0 | –99.4 | .. |
| Gas | Exports | 23.1 | 33.0 | 88.5 | 88.2 | 88.0 | 88.0 | .. |
| | Imports | 0.3 | 0.5 | 3.2 | 3.0 | 1.0 | 1.0 | .. |
| | Net Imports | –22.8 | –32.5 | –85.3 | –85.2 | –86.9 | –86.9 | .. |
| Electricity | Exports | 1.4 | 1.6 | 3.4 | 3.1 | 5.4 | 4.7 | .. |
| | Imports | 0.2 | 1.5 | 1.4 | 1.4 | 3.4 | 3.3 | .. |
| | Net Imports | –1.2 | –0.0 | –2.0 | –1.7 | –2.0 | –1.4 | .. |
| **TOTAL STOCK CHANGES** | | **–1.6** | **–4.0** | **1.6** | **4.3** | **–** | **–** | **..** |
| **TOTAL SUPPLY (TPES)** | | **161.0** | **209.1** | **248.2** | **258.5** | **306.8** | **350.2** | **..** |
| Coal[1] | | 15.3 | 24.3 | 30.7 | 29.6 | 28.3 | 22.1 | .. |
| Oil | | 81.0 | 77.1 | 88.8 | 94.2 | 96.4 | 107.4 | .. |
| Gas | | 37.3 | 54.7 | 71.5 | 75.3 | 110.1 | 145.9 | .. |
| Comb. Renewables & Wastes[2] | | 7.8 | 8.1 | 10.5 | 11.3 | 17.0 | 19.0 | .. |
| Nuclear | | 4.1 | 19.4 | 20.0 | 19.7 | 23.4 | 22.1 | .. |
| Hydro | | 16.7 | 25.5 | 28.6 | 30.1 | 33.3 | 34.6 | .. |
| Geothermal | | – | – | – | – | 0.4 | 0.4 | .. |
| Solar/Wind/Other[3] | | – | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | .. |
| Electricity Trade[5] | | –1.2 | –0.0 | –2.0 | –1.7 | –2.0 | –1.4 | .. |
| ***Shares (%)*** | | | | | | | | |
| *Coal* | | *9.5* | *11.6* | *12.4* | *11.4* | *9.2* | *6.3* | .. |
| *Oil* | | *50.3* | *36.9* | *35.8* | *36.4* | *31.4* | *30.7* | .. |
| *Gas* | | *23.2* | *26.2* | *28.8* | *29.1* | *35.9* | *41.7* | .. |
| *Comb. Renewables & Wastes* | | *4.9* | *3.9* | *4.2* | *4.4* | *5.5* | *5.4* | .. |
| *Nuclear* | | *2.5* | *9.3* | *8.1* | *7.6* | *7.6* | *6.3* | .. |
| *Hydro* | | *10.4* | *12.2* | *11.5* | *11.7* | *10.8* | *9.9* | .. |
| *Geothermal* | | – | – | – | – | *0.1* | *0.1* | .. |
| *Solar/Wind/Other* | | – | – | – | – | – | – | .. |
| *Electricity Trade* | | *–0.7* | – | *–0.8* | *–0.7* | *–0.7* | *–0.4* | .. |

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

## DEMAND

### FINAL CONSUMPTION BY SECTOR

| | 1973 | 1990 | 2001 | 2002P | 2010 | 2020 | 2030 |
|---|---|---|---|---|---|---|---|
| **TFC** | **133.2** | **161.3** | **185.0** | **195.4** | **221.5** | **251.0** | **..** |
| Coal[1] | 5.2 | 3.1 | 3.2 | 4.3 | 4.7 | 5.4 | .. |
| Oil | 77.6 | 70.6 | 81.5 | 83.6 | 86.8 | 98.2 | .. |
| Gas | 23.7 | 43.3 | 48.5 | 52.7 | 63.4 | 72.1 | .. |
| Comb. Renewables & Wastes[2] | 7.6 | 7.8 | 9.8 | 10.4 | 15.6 | 17.5 | .. |
| Geothermal | – | – | – | – | – | – | .. |
| Solar/Wind/Other | – | – | – | – | – | – | .. |
| Electricity | 18.9 | 36.0 | 41.1 | 43.6 | 50.3 | 57.0 | .. |
| Heat | 0.1 | 0.6 | 0.8 | 0.9 | 0.7 | 0.9 | .. |
| ***Shares (%)*** | | | | | | | |
| *Coal* | *3.9* | *1.9* | *1.7* | *2.2* | *2.1* | *2.1* | .. |
| *Oil* | *58.3* | *43.7* | *44.1* | *42.8* | *39.2* | *39.1* | .. |
| *Gas* | *17.8* | *26.8* | *26.2* | *27.0* | *28.6* | *28.7* | .. |
| *Comb. Renewables & Wastes* | *5.7* | *4.8* | *5.3* | *5.3* | *7.0* | *7.0* | .. |
| *Geothermal* | – | – | – | – | – | – | .. |
| *Solar/Wind/Other* | – | – | – | – | – | – | .. |
| *Electricity* | *14.2* | *22.3* | *22.2* | *22.3* | *22.7* | *22.7* | .. |
| *Heat* | *0.1* | *0.4* | *0.5* | *0.4* | *0.3* | *0.3* | .. |
| **TOTAL INDUSTRY[6]** | **52.8** | **63.2** | **71.3** | **77.8** | **97.5** | **111.1** | **..** |
| Coal[1] | 4.7 | 3.0 | 3.2 | 4.1 | 4.6 | 5.3 | .. |
| Oil | 21.4 | 18.7 | 21.7 | 22.8 | 24.9 | 27.6 | .. |
| Gas | 11.9 | 20.2 | 20.3 | 22.4 | 31.2 | 36.2 | .. |
| Comb. Renewables & Wastes[2] | 5.7 | 6.2 | 8.0 | 8.6 | 13.6 | 15.3 | .. |
| Geothermal | – | – | – | – | – | – | .. |
| Solar/Wind/Other | – | – | – | – | – | – | .. |
| Electricity | 9.1 | 14.4 | 17.2 | 19.1 | 22.4 | 25.8 | .. |
| Heat | 0.1 | 0.6 | 0.8 | 0.8 | 0.7 | 0.9 | .. |
| ***Shares (%)*** | | | | | | | |
| *Coal* | *8.9* | *4.8* | *4.5* | *5.3* | *4.8* | *4.8* | .. |
| *Oil* | *40.4* | *29.5* | *30.5* | *29.3* | *25.5* | *24.9* | .. |
| *Gas* | *22.5* | *32.0* | *28.5* | *28.8* | *32.0* | *32.6* | .. |
| *Comb. Renewables & Wastes* | *10.8* | *9.8* | *11.2* | *11.0* | *14.0* | *13.8* | .. |
| *Geothermal* | – | – | – | – | – | – | .. |
| *Solar/Wind/Other* | – | – | – | – | – | – | .. |
| *Electricity* | *17.2* | *22.9* | *24.2* | *24.5* | *23.0* | *23.2* | .. |
| *Heat* | *0.2* | *1.0* | *1.2* | *1.1* | *0.8* | *0.8* | .. |
| **TRANSPORT[7]** | **35.3** | **44.2** | **52.7** | **53.6** | **64.3** | **75.1** | **..** |
| **TOTAL OTHER SECTORS[8]** | **45.1** | **54.0** | **61.0** | **64.0** | **59.7** | **64.8** | **..** |
| Coal[1] | 0.4 | 0.1 | 0.0 | 0.1 | 0.1 | 0.1 | .. |
| Oil | 21.3 | 10.9 | 11.9 | 12.1 | 6.5 | 6.9 | .. |
| Gas | 11.9 | 20.2 | 23.8 | 25.7 | 24.5 | 25.7 | .. |
| Comb. Renewables & Wastes[2] | 1.9 | 1.6 | 1.8 | 1.8 | 2.0 | 2.2 | .. |
| Geothermal | – | – | – | – | – | – | .. |
| Solar/Wind/Other | – | – | – | – | – | – | .. |
| Electricity | 9.5 | 21.2 | 23.5 | 24.2 | 26.7 | 30.0 | .. |
| Heat | – | 0.0 | 0.0 | 0.0 | – | – | .. |
| ***Shares (%)*** | | | | | | | |
| *Coal* | *0.9* | *0.1* | *0.1* | *0.2* | *0.1* | *0.1* | .. |
| *Oil* | *47.4* | *20.2* | *19.4* | *18.9* | *10.8* | *10.7* | .. |
| *Gas* | *26.3* | *37.4* | *38.9* | *40.2* | *41.0* | *39.6* | .. |
| *Comb. Renewables & Wastes 09-03-2004 Rev.* | *4.2* | *3.0* | *3.0* | *2.9* | *3.3* | *3.3* | .. |
| *Geothermal* | – | – | – | – | – | – | .. |
| *Solar/Wind/Other* | – | – | – | – | – | – | .. |
| *Electricity* | *21.2* | *39.3* | *38.5* | *37.8* | *44.7* | *46.2* | .. |
| *Heat* | – | – | – | – | – | – | .. |

Unit: Mtoe

## DEMAND

### ENERGY TRANSFORMATION AND LOSSES

| | 1973 | 1990 | 2001 | 2002P | 2010 | 2020 | 2030 |
|---|---|---|---|---|---|---|---|
| **ELECTRICITY GENERATION**[9] | | | | | | | |
| **INPUT (Mtoe)** | **36.1** | **70.7** | **86.9** | **87.1** | **95.0** | **100.3** | **..** |
| **OUTPUT (Mtoe)** | **23.2** | **41.4** | **50.6** | **51.7** | **60.9** | **68.9** | **..** |
| (TWh gross) | 270.1 | 481.9 | 587.9 | 601.0 | 708.2 | 800.6 | .. |
| *Output Shares (%)* | | | | | | | |
| *Coal* | *12.9* | *17.1* | *20.1* | *19.5* | *14.1* | *10.3* | .. |
| *Oil* | *3.4* | *3.4* | *2.9* | *2.4* | *0.7* | *0.5* | .. |
| *Gas* | *6.0* | *2.0* | *6.1* | *5.7* | *15.7* | *26.2* | .. |
| *Comb. Renewables & Wastes* | – | *0.8* | *1.2* | *1.4* | *2.0* | *2.0* | .. |
| *Nuclear* | *5.6* | *15.1* | *13.0* | *12.6* | *12.7* | *10.6* | .. |
| *Hydro* | *72.1* | *61.6* | *56.7* | *58.3* | *54.6* | *50.2* | .. |
| *Geothermal* | – | – | – | – | *0.1* | *0.1* | .. |
| *Solar/Wind/Other* | – | *0.0* | *0.1* | *0.1* | *0.1* | *0.1* | .. |
| **TOTAL LOSSES** | **31.2** | **48.7** | **60.8** | **69.1** | **85.3** | **99.2** | **..** |
| *of which:* | | | .. | | | | |
| Electricity and Heat Generation[10] | 12.8 | 28.6 | 35.5 | 34.6 | 33.3 | 30.6 | .. |
| Other Transformation | 1.9 | –1.3 | –3.4 | 2.3 | 13.7 | 13.9 | .. |
| Own Use and Losses[11] | 16.5 | 21.4 | 28.7 | 32.3 | 38.3 | 54.7 | .. |
| **Statistical Differences** | **–3.5** | **–0.9** | **2.4** | **–6.1** | **–** | **–** | **..** |

## INDICATORS

| | 1973 | 1990 | 2001 | 2002P | 2010 | 2020 | 2030 |
|---|---|---|---|---|---|---|---|
| GDP (billion 1995 US$) | 322.34 | 534.39 | 727.30 | 751.04 | 897.37 | 1116.62 | .. |
| Population (millions) | 22.49 | 27.70 | 31.11 | 31.41 | 33.20 | 35.30 | .. |
| TPES/GDP[12] | 0.50 | 0.39 | 0.34 | 0.34 | 0.34 | 0.31 | .. |
| Energy Production/TPES | 1.23 | 1.31 | 1.53 | 1.52 | 1.72 | 1.58 | .. |
| Per Capita TPES[13] | 7.16 | 7.55 | 7.98 | 8.23 | 9.24 | 9.92 | .. |
| Oil Supply/GDP[12] | 0.25 | 0.14 | 0.12 | 0.13 | 0.11 | 0.10 | .. |
| TFC/GDP[12] | 0.41 | 0.30 | 0.25 | 0.26 | 0.25 | 0.22 | .. |
| Per Capita TFC[13] | 5.92 | 5.82 | 5.95 | 6.22 | 6.67 | 7.11 | .. |
| Energy-related $CO_2$ | | | .. | | | | |
| Emissions (Mt $CO_2$)[14] | 375.1 | 430.2 | 519.5 | .. | 577.4 | 665.7 | .. |
| $CO_2$ Emissions from Bunkers | | | | | | | |
| (Mt $CO_2$) | 6.3 | 5.6 | 6.5 | .. | 5.6 | 5.7 | .. |

## GROWTH RATES (% per year)

| | 73–79 | 79–90 | 90–01 | 01–02 | 02–10 | 10–20 | 20–30 |
|---|---|---|---|---|---|---|---|
| TPES | 2.9 | 0.8 | 1.6 | 4.1 | 2.2 | 1.3 | .. |
| Coal | 4.4 | 1.9 | 2.2 | –3.7 | –0.6 | –2.4 | .. |
| Oil | 2.1 | –1.6 | 1.3 | 6.0 | 0.3 | 1.1 | .. |
| Gas | 2.7 | 2.1 | 2.5 | 5.2 | 4.9 | 2.9 | .. |
| Comb. Renewables & Wastes | –1.6 | 1.2 | 2.3 | 8.2 | 5.2 | 1.2 | .. |
| Nuclear | 15.7 | 6.4 | 0.3 | –1.5 | 2.2 | –0.6 | .. |
| Hydro | 3.8 | 1.8 | 1.1 | 5.2 | 1.2 | 0.4 | .. |
| Geothermal | – | – | – | – | – | – | .. |
| Solar/Wind/Other | – | – | 29.0 | 81.8 | – | – | .. |
| TFC | 2.4 | 0.4 | 1.3 | 5.7 | 1.6 | 1.3 | .. |
| Electricity Consumption | 4.7 | 3.4 | 1.2 | 6.0 | 1.8 | 1.3 | .. |
| Energy Production | 1.0 | 2.4 | 3.0 | 3.3 | 3.8 | 0.5 | .. |
| Net Oil Imports | – | – | 8.6 | 20.9 | 12.1 | –1.9 | .. |
| GDP | 3.6 | 2.7 | 2.8 | 3.3 | 2.2 | 2.2 | .. |
| Growth in the TPES/GDP Ratio | –0.7 | –1.8 | –1.2 | 0.9 | –0.1 | –0.9 | .. |
| Growth in the TFC/GDP Ratio | –1.1 | –2.2 | –1.5 | 2.3 | –0.7 | –0.9 | .. |

Please note: Rounding may cause totals to differ from the sum of the elements.

# FOOTNOTES TO ENERGY BALANCES AND KEY STATISTICAL DATA

1. Includes lignite.
2. Comprises solid biomass. Data are often based on partial surveys and may not be comparable between countries.
3. Other includes tide and wave.
4. Total net imports include combustible renewables.
5. Total supply of electricity represents net trade. A negative number indicates that exports are greater than imports.
6. Includes non-energy use.
7. Includes less than 1% non-oil fuels.
8. Includes residential, commercial, public service and agricultural sectors.
9. Inputs to electricity generation include inputs to electricity and CHP plants. Output refers only to electricity generation.
10. Losses arising in the production of electricity and heat at public utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of 33% for nuclear, 10% for geothermal and 100% for hydro.
11. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
12. Toe per thousand US dollars at 1995 prices and exchange rates.
13. Toe per person.
14. "Energy-related $CO_2$ emissions" specifically means $CO_2$ from the combustion of the fossil fuel components of TPES (*i.e.* coal and coal products, peat, crude oil and derived products and natural gas), while $CO_2$ emissions from the remaining components of TPES (*i.e.* electricity from hydro, other renewables and nuclear) are zero. Emissions from the combustion of biomass-derived fuels are not included, in accordance with the IPCC greenhouse gas inventory methodology. Also in accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2001 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

## INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

The member countries* of the International Energy Agency (IEA) seek to create the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants.

In order to secure their objectives they therefore aim to create a policy framework consistent with the following goals:

1. **Diversity, efficiency and flexibility within the energy sector** are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2. Energy systems should have **the ability to respond promptly and flexibly to energy emergencies**. In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3. **The environmentally sustainable provision and use of energy** is central to the achievement of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should where practicable have regard to the Polluter Pays Principle.

4. **More environmentally acceptable energy sources** need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of IEA members wish to retain and improve the nuclear option for the

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5. **Improved energy efficiency** can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6. Continued **research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7. **Undistorted energy prices** enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8. **Free and open trade** and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9. **Co-operation among all energy market participants** helps to improve information and understanding, and encourage the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at their 4 June 1993 meeting in Paris.)

## GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention and subsequently abbreviated, this glossary provides a quick and central reference for many of the abbreviations used.

| | |
|---|---|
| ACR | Advanced CANDU Reactor |
| AECB | Atomic Energy Control Board |
| AECL | Atomic Energy of Canada Limited |
| bbl | barrel |
| bcm | billion cubic metres |
| CANDU | Canada Deuterium Uranium nuclear reactor |
| CANMET | Canada Centre for Mineral and Energy Technology |
| CAPP | Canadian Association of Petroleum Producers |
| CCAF | Climate Change Action Fund |
| CEM | Council of Energy Ministers |
| CHP | combined production of heat and power; sometimes, when referring to industrial CHP, the term "co-generation" is used |
| CIPEC | Canadian Industry Program for Energy Conservation |
| CNOPB | Canada-Newfoundland Offshore Petroleum Board |
| CNSC | Canadian Nuclear Safety Commission |
| CNSOPB | Canada-Nova Scotia Offshore Petroleum Board |
| EAE | Energy Efficiency and Alternative Energy Program |
| EUB | Alberta Energy and Utilities Board |
| FERC | US Federal Energy Regulatory Commission |
| GDP | gross domestic product |
| GHG | greenhouse gases |
| GST | goods & services tax |
| GW | gigawatt, or one watt $\times 10^9$ |
| kbd | thousand barrels per day |
| LDC | local distribution companies. |
| LNG | liquefied natural gas |

| | |
|---|---|
| LPG | liquefied petroleum gas; refers to propane, butane and their isomers, which are gases at atmospheric pressure and normal temperature |
| mbd | million barrels per day |
| mcm | million cubic metres |
| Mt | million tonnes |
| Mtoe | million tonnes of oil equivalent; see toe |
| MW | megawatt of electricity, or one watt $\times 10^6$ |
| MWh | megawatt-hour = one megawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^6$ |
| NABEST | National Advisory Board on Energy Science and Technology |
| NAFTA | North American Free Trade Agreement |
| NERC | North American Electric Reliability Council |
| NFPRER | National Framework for Petroleum Refinery Emissions Reductions |
| $NO_x$ | oxides of nitrogen |
| NRCan | Natural Resources Canada |
| OAG | Office of the Auditor General |
| OCIPEP | The Office of Critical Infrastructure Protection and Emergency Preparedness |
| OECD | Organisation for Economic Co-operation and Development |
| OEE | Office of Energy Efficiency |
| OPG | Ontario Power Generation Inc. |
| PERD | Program of Energy Research and Development |
| PJ | petajoule |
| POWEREX | British Columbia Power Export Corporation |
| R&D | research and development, especially in energy technology; may include the demonstration and dissemination phases as well |
| SEPAC | Smaller Explorers and Producers Association of Canada |
| TEAM | Climate Change Technology Early Action Measures |
| TFC | total final consumption of energy; the difference between TPES and TFC consists of net energy losses in the production of electricity and synthetic gas, refinery use and other energy sector uses and losses |
| toe | tonne of oil equivalent, defined as $10^7$ kcal |
| TPA | third-party access |
| TPES | total primary energy supply |
| TW | terawatt, or one watt $\times 10^{12}$ |
| TWh | terawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^{12}$ |
| UNFCCC | United Nations Framework Convention on Climate Change. |
| VCR | Voluntary Challenge and Registry Program. |

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