Terasen Gas

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September 21, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application (the "Application")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Panel Information Request ("IR") No. 1

On May 15, 2009, the Terasen Utilities filed the Application as referenced above. On September 2, 2009, the Commission filed Commission Panel IR No. 1 (Exhibit A-7) and requested the Terasen Utilities file its response by September 21, 2009.

The Terasen Utilities respectfully submit the attached response to Commission Panel IR No. 1. Attached is a replacement Binder Cover and Spine for Volume 3 to allow binder holders to insert these responses at the back of Volume 3.

If there are any questions regarding the attached, please contact the undersigned.

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): Registered Parties

1.0 Business Risk

TGI states that a key driver of competitiveness and business risk that has changed for TGI in recent years is the Provincial Government's climate change and energy policies which have increased the risk inherent to TGI's core natural gas business.

During the 2008 LTAP proceeding the Independent Power Producers Association of British Columbia ("IPPBC") introduced its witness Dr Jaccard who spoke to a report dated August 22, 2008 and entitled "A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis" (2008 LTAP Exhibit C17-6).

Please provide Terasen's analysis of this report as it relates to the role of a natural gas LDC in BC. What outlook is implied in the report for Terasen's long term business model? What factors should the Commission be addressing in its regulation of natural gas Local Distribution Companies ("LDC") in BC? Please address the orderly discharge of the LDC's liabilities including income tax obligations, pension obligations, and long-term debt.

Response:

Please provide Terasen's analysis of this report as it relates to the role of a natural gas LDC in BC. What outlook is implied in the report for Terasen's long term business model?

The report (Attachment 1.0) dated August 22, 2008 entitled "A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sector and regional" ("Report"), outlines a plan (or roadmap) to reduce GHG emissions in Canada by 65 per cent from a 2006 baseline by 2050. This roadmap points to considerable increased risk for natural gas utilities in BC due to the fact that the report identifies a path to GHG emission reductions in buildings in which natural gas would no longer be used in homes or businesses to provide space and water heating.[1] The main premise behind the Report is to expand the use of electricity in all sectors of the economy (transportation – plug in vehicles, and ground source heat pumps and electric baseboards in residential/commercial buildings) that is produced from renewable generation sources. By doing this, fossil fuel consumption including natural gas is displaced. To meet the BC provincially-mandated GHG reduction targets by 2020 and 2050, immediate actions will need to be taken in all sectors of the economy given that many sources of GHG emissions (buildings/homes, fossil fuel-based electricity generation, transportation

[1] A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sector and regional, Aug 22, 2008, page 20, states: Most emission reductions are attained through the adoption of electric space and water heating systems. By 2050, virtually the entire space heating stock consists of ground source heat pumps or electric baseboards, and the entire water heating stock is electric.

vehicles, oil and gas production) have useful lives that span many years. Therefore, the impact to natural gas LDC's would be felt well in advance of 2050.

Reports of this type to policy makers, with access by consumers, can and does shape the long-term view of policy makers and the broader community respecting a product (in this case, natural gas) and may well be influential in formulating public policy that has long-term negative impacts on the demand for that product (i.e. natural gas). The outcome identified in the Report would reduce throughput on the Terasen natural gas delivery systems, which all else equal, will increase the unit costs to the remaining natural gas customers. In the extreme, the Company could have stranded assets if the roadmap that is outlined in the Report materializes.

The picture that is painted by the Report is consistent with increased business risk that is being faced by natural gas utilities in BC as presented in the Application in Tab 1 Business Risk pages 3 to 9. Given that most BC electricity production comes from, or in the future is expected to come from, a renewable source, some policy makers and stakeholders will conclude that electricity should be used to a greater degree to help BC achieve its GHG reduction targets at the expense of natural gas.

What factors should the Commission be addressing in its regulation of natural gas Local Distribution Companies ("LDC") in BC?

To assist LDC's to meet these challenges, efforts to adapt to changing market demands and expand into complimentary alternative energy offerings by regulated utilities such as:

- renewable natural gas production (i.e., bio-methane from various sources),
- integrated community energy solutions involving natural gas, solar thermal, geo-exchange, biomass, waste heat capture, etc.

should not be frustrated by the Commission, particularly as these offerings would fall under the jurisdiction of the Commission as regulated energy delivery services. However, the approval of such efforts would still leave a significant increase in risk relating to policy initiatives and public perception, particularly when the Report is proposing a path to GHG emission reductions that would have a major impact on natural gas consumption.

Please address the orderly discharge of the LDC's liabilities including income tax obligations, pension obligations, and long-term debt.

The increased risks to TGI from policy directions that could arise from the Technology Roadmap Report are real. TGI has begun to address the orderly discharge of it tax, pension and long term debt obligations through its revenue requirements application regarding its depreciation rates, i.e. attempting to ensure that the company is recovering costs of service inputs from customers who are receiving the service and dealing with the un-recovered losses currently residing in its net property plant and equipment balances. As this capital is recovered from customers the company will manage its long term debt portfolio accordingly.

At present, due to the fact that the Commission, like most Canadian regulators, only allows the inclusion of flow-through taxes in rates, the company is not recovering the actual expected tax cost of service from current customers and this is one of the factors that gives rise to increased business/financial risk for TGI vs US utilities that recover current and future income taxes in rates. This increases the prospect of stranded assets in the future. Terasen has adapted its business strategy in order to be best positioned to meet these challenges over time and continue as a going concern in BC, but the ideas expressed by persons of influence such as Dr. Jaccard are likely to shape future policy direction of government, and the public's perception of natural gas, exacerbating the challenges discussed in the Application.

2.0 Preferred Shares

The Application describes conditions in the Canadian preferred share market, the direction of yields and the type of preferred share structures that were issued in the period 2006 to 2008.

Please provide an analysis by TGI of the applicability of an issue of preferred shares by TGI in order to reduce the ratio of debt in its capital structure. In particular the analysis should address TGI's preferred share rating, the accounting and tax implications of having preferred shares in TGI's capital structure, the impact of preferred shares on TGI's revenue requirements compared to equity and/or long term debt, together with an illustrative term sheet for the issue of (say) $50 million of preferred shares by TGI.

Response:

1. TGI does not believe an issue of preferred shares is suitable as a proxy for common equity to reduce the financial risk of TGI by reducing its debt balance in its capital structure, for the following reasons:

   a. Preferred shares are a hybrid security that can exhibit varying degrees of debt and equity characteristics depending on the features: retractable at option of holder, redeemable at option of issuer, conversion into common equity, whether the issue is perpetual, and whether dividends are cumulative or mandatory. The accounting treatment, as discussed below, can treat preferred shares as either debt or equity. More importantly, rating agencies allocate an equity and debt component to preferred shares for ratings determinations, irrespective of accounting treatment. The debt and equity allocation is specific to each issue, but in general, rating agencies assign a higher equity credit (70-100% equity) to preferred shares that are non-redeemable or have mandatory conversion to common equity features and assign a much lower equity credit (higher debt credit) to those that exhibit redemption or retraction features (0% to 70% equity).

   TGI can issue either retractable shares, which are redeemable at holders option, that are treated as debt by GAAP and by rating agencies, or rate reset preferred shares, which reset the dividend yields at predetermined periods (every five years at a predetermined reset yield) and are redeemable at the issuer's option on reset date. Rating agencies typically accord in the range of 25%-70%% equity treatment to rate reset preferred shares. Moody's typically assigns the lowest equity treatment, in the 25% to 50% range, S&P is understood to allocate between 40% to 60% equity, while DBRS may accord 50-70% equity treatment.

   These types of preferred shares, as they are hybrid instruments (debt and equity treatment) do not fully address capital structure ratio issues for rating agency purposes, and as the shares are senior ranking to common equity, do not reduce the financial risk faced by a common equity holder, therefore, are inefficient as a form of equity.

b. Preferred shares, as noted below, are not tax-deductible, therefore, on a debt equivalent basis, the debt component of these hybrid instruments are expensive forms of debt.

c. Utilizing preferred shares as a component of the capital structure will increase TGI's financing risk as the market for preferred shares is less robust than either the debt or equity market. Preferred shares are typically a retail investor driven market, which are more susceptible to periods of shut-down where issuers are not able to access the market. As well, demand for preferred shares is somewhat dictated by the features of the instruments. The rate reset shares that may be issued by TGI is not always available as investors may prefer other forms of instrument, that TGI may not be able to issue (an example would be shares convertible into common equity, which TGI could not issue as it does not have publicly traded equity).

d. TGI would be a small, infrequent issuer of preferred shares and with no common stock outstanding, has no retail following, which will exacerbate the financing risk noted above, relative to more frequent issuers of preferred shares, and will lead to higher yields.

e. Given the hybrid nature of preferred shares, and market structure, TGI is of the view that preferred equity is an inefficient form of capital and not suitable to utilize as a replacement to equity.

2. TGI does not have a preferred rating and has not had any discussions with rating agencies as to what its ratings would be. TGI estimates a reasonable rating, based on discussions with investment banks, would be in the Pfd-3(high) to Pfd-2 range by DBRS, Baa3 to Baa1 range by Moody's (Moody's does not have a separate preferred share rating scale, utilizing one scale based on seniority of claim), and P-3(High) to P-2 range by S&P.

3. According to current Canadian GAAP and IFRS (to be adopted by Canadian GAAP in 2011), a preferred share may be recorded as a liability or equity depending on the particular rights attached to the share. A preferred share that provides for redemption on a specific date or is retractable by the holder is a financial liability. When the redemption is at the discretion of the issuer, it is not an obligation until the issuer formally exercises its option. When preferred shares are non-redeemable, the appropriate classification is then determined by whether distributions to holders of the preferred shares, either cumulative or non-cumulative, are at the discretion of the issuer. If so the shares are considered equity. Note that rating agency's determination of debt equivalency does not follow accounting treatment, as the agencies may determine an instrument contains debt-like features that is otherwise treated as equity under GAAP and IFRS.

4. Dividends on preferred shares are not deductible for tax purposes, therefore, the revenue requirement needs to recover a pre-tax equivalent dividend yield, similar the allowed return on common equity.

5. RBC Capital Markets has provided a generic term sheet that summarizes the expected terms and conditions that TGI would be subject to under a potential issuance of rate reset preferred shares. As noted above, rate re-set preferred shares are the typical hybrid equity structure that TGI might be able to issue. See Attachment 2.0.

6. TGI requested indicative pricing currently available in the market from RBC Capital Markets and TD Securities on rate reset preferred shares. The indicative dividend yield is in the range of 5.25% and 5.75%. The rate reset spread over the 5-year benchmark bond at reset date would be approximately 2.5% to 3.0%. Note that this is indicative based on current market conditions, and TGI does not represent that this rate is achievable.

7. The indicative effect on the annual Revenue Requirement would be as follows:

Table: Revenue requirement impact of issuing preferred vs. common shares.

Type	Rate*	Issuance	Rate Impact
Preferreds	5.50%	$ 100,000,000	$ 4,947,143
Common (current)	8.47%	$ 50,000,000	$ 4,320,000
Common (requested)	11.00%	$ 50,000,000	$ 6,127,143

** Rate is tax-affected by 1-tax rate. Assumed tax rate is 30%.*

1) The revenue requirement impact is net of interest, assuming the new capital displaces an equivalent amount of debt, with the savings based on a 5-year new issue rate of approximately 3.5%.

2) Preferred shares receive only notional equity treatment by rating agencies. The treatment can range between 25% - 70% equity debt treatment depending on the rating agency, as discussed above, therefore, to provide the same capital structure impact that compares to $50 million of common equity, a greater number of preferred shares would be required. A mid-point of 50% equity treatment has been assumed for the example, although there is a chance the equity allocation is less, which would require additional preferred equity on an equivalency basis.

3) Although additional preferred shares might improve the credit quality of TGI's senior debt, they will not reduce the overall financial risk to equity holders, for two reasons –

a) preferred shares are a senior claim on the earnings and assets of the company, ranking ahead of common equity; and b) the cost of the preferred shares are more expensive than debt given the tax treatment.

4) The preferred shares include an estimated 2.75% issuance cost (commission, new issue costs, listing fees) that is amortized over 5 years (to the date of first redemption). Common equity issue costs are not directly charged through by Fortis and are not included in the above analysis.

3.0 Capital Structure

TGI includes unfunded debt in its capital structure. Please address the pros and cons of excluding unfunded debt from a utility's capital structure.

The Commission Panel would also be interested in the treatment of unfunded debt for the purposes of determining the cost of capital followed by: i) other regulatory bodies in Canada and ii) comparable US LDCs.

Response:

Unfunded debt in TGI's capital structure comprises short-term debt which (1) finances working capital and rate base; (2) represents bridge financing between issuances of long-term debt; and (3) is the "plug" which equates rate base to total capital. Because TGI actually relies on short-term debt to finance working capital and rate base assets, the cost of short-term or unfunded debt represents an actual component of TGI's cost of capital and is justifiably included. Further, because TGI is regulated on the basis of a deemed capital structure, where the regulated capital structure is equated to rate base, there is no way to exclude unfunded debt from the regulated capital structure. Thus in regulatory jurisdictions in Canada that rely on deemed capital structures for ratemaking purposes (AUC, OEB, Régie de l'Énergie, NEB), unfunded debt is also used as a means to equate rate base and capitalization.

U.S. LDCs are typically regulated on the basis of actual capital structures, that is, the actual capital structure ratios in conjunction with the respective cost rates of the various forms of capital are applied to the rate base to derive the cost of capital dollars to be included in revenue requirement. Consequently, unfunded debt is not used as a plug to equate rate base and capitalization as is the case when deemed capital structures are used. However, where short-term debt is used to finance rate base assets, it is typically included in the gas utilities' regulated capital structures (i.e., Atlanta Gas Light (GA, TN), ATMOS Energy (GA, TN), New Jersey Natural Gas (NJ), NICOR Gas (Il), Northwest Natural Gas (WA), Piedmont Natural Gas (NC), South Jersey Gas (NJ), Washington Gas Light (MD, VA, DC)). If, instead, the utility demonstrates that the outstanding short-term debt is used solely as bridge financing and allocated to construction work in progress (i.e., Northwest Natural Gas, Order 99-697, Public Utility Commission of Oregon), short-term debt is excluded from the actual capital structure determined to be financing rate base.

4.0 IFRS

Please comment on the potential impact on TGI's capital structure of TGI's adopting IFRS. The Commission Panel understands that this issue may have been addressed in TGI's current RRA. Please file any relevant evidence in this proceeding.

Response:

The table below has been taken from the TGI 2010 – 2011 Revenue Requirement Application, and as such assumes that the Commission approves the current RRA as filed, that the current capital structure percentages are maintained, and that TGI's regulatory assets and liabilities will all meet the recognition criteria under the IFRS Rate-regulated Activities Exposure Draft.

TGI's capital structure for regulatory purposes is determined as a percentage of rate base. Any IFRS changes that impact rate base will also impact the dollar value of the debt and equity components of the capital structure, but not the overall percentages, which are the subject of this proceeding.

Based on Table C-11-1 filed in TGI's 2010-2011 Revenue Requirements Application, and reproduced below, rate base is expected to decrease by approximately $34 million in 2010, which would translate into a decrease in debt by 64.99% of that amount or approximately $22 million, and a decrease in equity by 35.01% of that amount or approximately $12 million before considering the relief being sought in this application. The change in the ROE to 11 per cent and the increase in the equity component of the capital structure to 40 per cent would have an impact on the earned return on rate base which is included as a component of the revenue requirement column. The impact of this change on the revenue requirement column of the 2010 table is a decrease in the revenue requirements of approximately $0.5 million from $40 million to $39.5 million (IFRS reduces rate base and therefore the earned return component of revenue requirements). There is no material impact on the revenue requirement column of the 2011 table.

		2010 Increase/(Decrease) over 2009			
Ref	Description	O&M	Dep'n	PP&E	Rev Req
a-1	Training costs previously capitalized	$ 2.2	$ (0.1)	$ (2.1)	$ 2.0
a-1	Feasibility studies previously capitalized	0.5	(0.0)	(0.5)	0.5
b-4.4	Capitalization of current service portion of pension and OPEBs	(0.6)	0.0	0.6	(0.6)
b-7	Inspection costs now capitalized	(1.3)	0.0	1.3	(1.2)
b-7	Commencement of depreciation		1.9	(1.9)	2.6
c	Depreciation study impacts		20.8	(20.8)	28.5
d	Reduction in overhead capitalized	11.2	(0.2)	(11.0)	10.6
e	Shared services with TGVI	(2.9)			(2.9)
f	Corporate services with Terasen Inc	0.5			0.5
		$ 9.6	$ 22.5	$ (34.5)	$ 40.0

		2011 Increase/(Decrease) over 2010			
Ref	Description	O&M	Dep'n	PP&E	Rev Req
b-9	2011 Pension and employee future benefits - annual expense	$ (2.0)		$ (1.4)	$ (2.0)
c	Depreciation study impacts		0.4	(0.4)	0.5
e	Shared services with TGVI	(0.4)			(0.4)
f	Corporate services with Terasen Inc	0.1			0.1
		$ (2.3)	$ 0.4	$ (1.8)	$ (1.7)

There may be some additional impact on TGI's financial statement (not regulatory) capital structure due to different treatment under IFRS for some non-regulated items, but the final conclusion on these items has not been determined.

5.0 US LDCs

Please comment on the difference in rate setting methodology between the Value Line US LDCs and TGI. The Commission Panel acknowledges that such a study might require an analysis of a large number of state regulatory practices, but it seeks such additional information on this topic that can reasonably be provided within the stipulated timeframe. In particular please comment on how the returns actually earned by the Value Line US LDCs compare with the ROEs they have been awarded by their regulators Further, to the extent possible, please provide an analysis of actual ROEs earned by the Value Line US LDCs over the five year period ended in 2008, compared with the ROE(s) awarded.

Response:

The rate setting methodologies of the Value Line US LDCs and TGI are quite similar. Both the Value Line US LDCs and TGI are subject to rate of return regulations which are designed to provide the companies an opportunity to recover prudently incurred costs and earn a fair rate of return on their investments. In addition, the US LDCs and TGI both benefit from the availability of cost recovery mechanisms that are designed to reduce regulatory lag. Specific information on state regulatory practices for US LDCs is summarized in the analysis provided in Attachment 5.0. Also see response to BCUC IR No. 1, 62.1, page 169, and response to BCUC IR No. 1, 74.3, page 199.

With regard to the requested comparison of actual and allowed ROEs for US utilities, Dr. Vander Weide notes that the requested information is difficult to obtain because actual ROEs for the operating utility subsidiaries in each state jurisdiction are generally not reported in the annual reports of the Value Line LDCs. Dr. Vander Weide is not aware of an efficient way to obtain information on the utility subsidiaries' actual ROEs in each state jurisdiction. However, Dr. Vander Weide's written evidence provides data on allowed ROEs for US natural gas utilities over the last three years. The average allowed ROE for gas utilities in 2008 was approximately 10.4 percent (see Exhibit 3 of Dr. Vander Weide's written evidence). Information on the actual ROEs for the total operations of the Value Line LDCs over the last five years is provided in the table below. As shown in these data, the average actual ROE for the Value Line LDCs over the last five years is 11.9 percent.

ROE and Standard Deviation of Returns for Value Line LDCs
2004 - 2008

Company	2004	2005	2006	2007	2008	Standard Deviation 2004 - 2008
AGL Resources	11.0%	12.9%	13.2%	12.7%	12.6%	0.86%
Atmos Energy	7.6%	8.5%	9.8%	8.7%	8.8%	0.79%
Laclede Group	10.1%	10.9%	12.5%	11.6%	11.8%	0.91%
New Jersey Resources	15.3%	17.0%	12.6%	10.1%	15.7%	2.77%
NICOR	13.1%	12.5%	14.7%	14.3%	12.3%	1.07%
Northwest Natural Gas	8.9%	9.9%	10.9%	12.5%	10.9%	1.34%
Piedmont Natural Gas	11.1%	11.5%	11.0%	11.9%	12.4%	0.58%
South Jersey Industries	12.5%	12.4%	16.3%	12.8%	13.1%	1.63%
WGL Holdings	11.7%	12.0%	10.3%	10.4%	11.6%	0.79%
Average	11.3%	12.0%	12.4%	11.7%	12.1%	1.19%
Average 2004 - 2008	11.9%					

Source: Value Line Investment Survey.
Value Line Reports, September 11, 2009

6.0 TGVI

TGI's Application deals at length with the business risks of TGI but is silent on those additional risks faced by TGVI which might justify the premium of 75bps requested. Please comment on the additional risks that might justify the premium of 75 bps.

Response:

As noted in the question the application deals with the business risks that are faced by TGI and how they have increased since the 2005 proceeding. These changes are dealt with in section 4 of the application and in more detail in Appendix 1 of the application. Section 5.2 of the application notes how these additional risk factors also apply to TGVI (and to TGW). Section 5.2.2 of the application relates to the continuation of the company specific risk premium for TGVI, requesting that it remain at 70 basis points over the new benchmark (rather than 75 as stated in the question). As noted, evidence on the relative business risk of TGVI versus TGI was presented in the 2005 hearing and those differentiators which are repeated below have not changed materially since that time.

In addition to the challenges and risks facing TGI both in 2005 and at present, Terasen Gas (Vancouver Island) Inc. must also deal with the added burdens of:

- Continuing to be a relatively young utility building a new market on Vancouver Island;
- Being disadvantaged by the differences in gas versus electric rate design methodologies and being burdened with the recovery of an accumulated deficit that peaked at approximately $88 million in 2002;
- Planning for the elimination of Provincial royalty revenues in 2012 that have ranged from $35 to $40 million in recent years and covering approximately 20% of the current cost of service;
- Being highly dependent on industrial load related to BC Hydro generation and the Vancouver Island Pulp Mill Joint Venture (VIGJV). Under climate change policies BC Hydro is discouraged from using the ICP for electricity generation and the VIGJV has de-contracted to its minimum allowed levels with its contracts expiring at the end of 2012;
- Greater security of supply risk due the fact that all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities; and
- Liability for the repayment of (originally) $75 million non-interest-bearing senior government debt, currently sitting as a credit to rate base, which when repaid will contribute to higher cost of service and impact the competitive position of the utility.

Since 2005, while TGVI has been able to recover the accumulated revenue deficiencies noted in the second bullet by setting its rates through a soft cap mechanism, it has done so by setting its rates at a level higher than that under traditional rate setting methodologies.

Now that it is on the verge of eliminating that burden, it is faced with the imminent loss of royalty revenues and significant impending rate shock.

The Mt. Hayes LNG facility is currently being constructed which will provide a degree of supply interruption protection but failure of the marine crossing pipeline segments would likely result in prolonged supply interruption beyond the capacity of the storage facility.

In the 2005 proceeding TGVI's expert witness Kathleen McShane provided the following testimony:

TGVI is requesting that the Commission approve a 40% common equity ratio and a 75 basis point incremental equity risk premium relative to the benchmark low risk utility. In my opinion, this proposal reasonably compensates for TGVI's level of business risk.

1. *TGVI is a relatively small greenfield utility (assets of approximately $550 million including the Revenue Deficiency Deferral Account (RDDA)), which has been operating for slightly less than 15 years. As a greenfield utility, its market is being built from the ground up. TGVI's rates have been structured to compete with alternative energy sources, and to induce potential customers to convert to natural gas. Until 2003, rates were set at a discount to competing fuels and were too low to recover TGVI's cost of service. As a result, TGVI had built up an accumulated revenue deficiency (RDDA) which peaked at approximately $88 million.*

2. *Since 2003 TGVI's rates have been based on a cost of service model, incorporating "soft caps" in the residential and commercial sectors, designed to maintain the utility's competitiveness versus electricity or oil as appropriate to the rate class. Nevertheless, TGVI's residential and small commercial rates are higher (on an efficiency-adjusted basis) than electricity rates.*

3. *TGVI's ability to build its residential and small commercial market has been hampered by relatively high natural gas prices, low population density in its service area (which translates into relatively high unit costs) and very competitive electricity rates.*

4. *TGVI's load remains largely industrial (close to 70%), attributable to seven pulp and paper mills (the Joint Venture) and a cogeneration plant. The contract with the Joint Venture was amended, and extended into the fall of 2004 for an additional two years past the original renewal period to 2012. However, under*

the amended contract the firm demand was reduced by approximately 67% compared to the prior agreement. The contract with BC Hydro, which relates to the cogeneration facility, is currently on a year-to-year basis and expires October 31, 2005. A second planned gas fired generation facility at Duke Point on Vancouver Island, which was expected to have contributed significant additional revenues to TGVI's operation, was recently cancelled by BC Hydro.

5. *TGVI faces greater supply risks than the typical LDC, due to its dependence on a single pipeline system that traverses rugged terrain, and comprises both underwater and marine crossings.*

6. *Revenues from BC Hydro, in conjunction with royalty payments pursuant to the Vancouver Island Natural Gas Pipeline Agreement (VINGPA), have allowed TGVI to reduce the RDDA to approximately $60 million at December 2004. Under VINGPA, TGVI receives royalty payments from the Provincial Government that reduce the cost of the gas commodity, which, in turn, improves the margin available to recover delivery costs.*

7. *While TGVI has an opportunity to recover the remainder of the RDDA (at $60 million, about 10% of total assts), it has no assurance that it will be able to do so. While, at present, TGVI is being assisted by the VINGPA royalty payments, those payments will terminate at the end of 2011. After 2011, TGVI's customers will be required to absorb the full commodity cost of gas. Further, TGVI has $75 million in interest free senior government loans outstanding that currently are a credit to rate base; as they are repaid, the rate base will rise, creating higher capital costs. The ability of TGVI to mitigate the impact of rising costs on customer rates will partly depend on its ability to add new customers and thus reduce its unit delivery costs. However, the ability to add new customers (both through conversion and new construction) hinges in large part on the competitiveness of TGVI's rates versus electricity rates. Given the intensely competitive market in which TGVI operates, there is a material risk that it will be unable to fully recover its full investment in utility assets.*

8. *As a greenfield utility in a very price-competitive service area, TGVI faces higher business risks than any of the major mature gas distribution utilities (i.e., ATCO Gas, Enbridge Gas, Gaz Metro, Terasen Gas and Union Gas). TGVI is more comparable to the smaller mature LDCs (AltaGas Utilities, Gazifère Inc., and Natural Resource Gas) and the two greenfield LDCs in the Maritime Provinces (Enbridge Gas New Brunswick and Heritage Gas).*

9. *The allowed common equity ratios and incremental equity risk premiums for the small mature and greenfield LDCs are as follows:*[2]

Table 1[3]

LDC	***Allowed Common Equity Ratio***	***Incremental Risk Premium (basis points)***
AltaGas Utilities	*41%*	*0*
Enbridge Gas New Brunswick	*50%*	*320* [a/]
Gazifère Inc.	*40%*	*40* [b/]
Heritage Gas	*45%*	*330* [c/]
Natural Resource Gas	*50%*	*0*

[a/] *Allowed ROE of 13% set in June 2000 when the average allowed ROE for major Canadian utilities was approximately 9.8%.*

[b/] *Relative to Gaz Metro.*

[c/] *Allowed ROE of 13% set in February 2003 when the average allowed ROE for major Canadian utilities was approximately 9.7%.*

10. *I would judge TGVI to face higher business risks than AltaGas Utilities and to be in the same business risk class as Gazifère Inc. and Natural Resource Gas. I view TGVI to be somewhat less risky than either of EGNB or Heritage Gas, due primarily to TGVI's larger customer base and the level of government support that it has received. However, all three are facing difficulties in building a market from the ground up. I would also judge TGVI to face higher business risks than FortisBC, for which the BCUC recently allowed a 40% common equity ratio and a 40 basis point equity risk premium relative to the benchmark low risk utility.*

[2] Excludes Pacific Northern Gas due to open request related to capital structure and ROE.

[3] Since the table was prepared in 2005, there have been no changes to either the EGNB or Heritage Gas ROEs and capital structures. AltaGas Utilities applied to the AUC in the Generic Cost of Capital Proceeding for an increase in its common equity ratio to 46% at an ROE of 11%; the decision is pending. Gazifère's risk premium is currently 28 basis points relative to Gaz Metro and 54 basis points relative to TGI. NRG's approved equity ratio is currently 42% and its incremental equity risk premium relative to Enbridge Gas Distribution is 50 basis points. Pacific Northern Gas has filed an application with the BCUC for a change in capital structure and equity risk premium.

11. *In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return. Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium proposed for TGVI is reasonable.*

Today, TGVI faces competition from a greater array of alternative energy choices for customers than it did in 2005 and with public sentiment more finely tuned to the climate change messages being touted by government and the media. As noted above, TGVI is not seeking to increase the equity in its capital structure and has not sought to increase its utility specific equity risk premium from that set by the Commission in its 2006 decision.

Given the incremental business risks set out in the Application which are faced by TGI also impact TGVI and the risk differentiators that existed in 2005 continue to substantially exist today, the 70 basis point risk premium approved by the Commission for TGVI in its 2006 decision represents a conservative premium for TGVI's business risk relative to TGI.

7.0 Metrics

Please provide a table with ROEs ranging from 7.75% to 11% and equity ratios ranging from 35% to 40% setting out the impact on TGI's following metrics:

- Times interest covered;
- Retained cash flow/debt; and
- Free cash flow/funds from operations.

Response:

TGI has calculated, in the table that follows, the three ratios based on Moody's published methodology using the TGI 2008 financial results with the following income statement and balance sheet adjustments:

- Allowed ROE at 7.75%, 8%, 9%, 10% and 11%;
- Equity ratio at 35.01%, 36%, 37%, 38%, 39% and 40%; and
- Removal of incentive earnings, which cease at the end of 2009.
- Capital structure changes occur on January 1, 2008 for increased equity scenarios.
- 2008 actual dividends are adjusted for incremental changes in Net Earnings.

ROE	Equity	Times Coverage	RCF/Debt	FCF/FFO
Actual (Includes incentive earnings)				
8.62%	**35.01%**	**1.80x**	**4.16%**	**-13.51%**
Adjusted (Excludes incentive earnings)				
8.62%	**35.01%**	**1.69x**	**4.16%**	**-14.22%**
Estimated (Excludes incentive earnings)				
7.75%	35.01%	1.60x	4.16%	-14.91%
7.75%	36.00%	1.63x	4.22%	-14.73%
7.75%	37.00%	1.67x	4.28%	-14.55%
7.75%	38.00%	1.70x	4.34%	-14.38%
7.75%	39.00%	1.74x	4.41%	-14.21%
7.75%	40.00%	1.77x	4.47%	-14.05%
8.00%	35.01%	1.63x	4.16%	-14.70%
8.00%	36.00%	1.66x	4.22%	-14.52%
8.00%	37.00%	1.69x	4.28%	-14.35%
8.00%	38.00%	1.73x	4.34%	-14.17%
8.00%	39.00%	1.77x	4.41%	-14.01%
8.00%	40.00%	1.80x	4.47%	-13.84%
9.00%	35.01%	1.73x	4.16%	-13.94%
9.00%	36.00%	1.77x	4.22%	-13.76%
9.00%	37.00%	1.81x	4.28%	-13.58%
9.00%	38.00%	1.85x	4.34%	-13.41%
9.00%	39.00%	1.89x	4.41%	-13.24%
9.00%	40.00%	1.94x	4.47%	-13.08%
10.00%	35.01%	1.84x	4.16%	-13.26%
10.00%	36.00%	1.88x	4.22%	-13.08%
10.00%	37.00%	1.93x	4.28%	-12.90%
10.00%	38.00%	1.97x	4.34%	-12.72%
10.00%	39.00%	2.02x	4.41%	-12.56%
10.00%	40.00%	2.07x	4.47%	-12.39%
11.00%	35.01%	1.95x	4.16%	-12.64%
11.00%	36.00%	1.99x	4.22%	-12.46%
11.00%	37.00%	2.04x	4.28%	-12.28%
11.00%	38.00%	2.09x	4.34%	-12.11%
11.00%	39.00%	2.14x	4.41%	-11.94%
11.00%	40.00%	2.20x	4.47%	-11.77%

Attachment 1.0

FINAL REPORT

A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis

August 22, 2008

Prepared for:
National Round Table on the Environment and the Economy

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Executive Summary

In 2007, the National Round Table on the Environment and the Economy (NRTEE) published *Getting to 2050: Canada's transition to a low-emissions future*, which simulated policies that could be used to attain deep reductions in greenhouse gas emissions over the medium- and long-term. The NRTEE has retained M.K. Jaccard and Associates to develop a technology roadmap derived from the *Getting to 2050* deep emissions reductions pathways that simulates a 20% reduction in Canada's GHG emissions from 2006 levels by 2020 and a 65% reduction in emissions by 2050. The purpose of a technology roadmap is to support strategic research, development, marketing, investment and policy decisions to achieve deep reductions in greenhouse gas emissions at the least cost to society. The technology roadmap identifies key technologies or their components for getting to this goal, the order in which they need to be achieved, and the required investment necessary for each step. It also shows which technologies may support the advancement of other sub-goals within the roadmap.

Besides identifying key GHG reduction technologies and their development path, the technology roadmap has the added feature of being grounded in a full scale modeling simulation of the Canadian economy. The CIMS model, a technology end-use model that integrates energy supply, demand, capital vintaging and realistic consumer and firm behavior in response to energy and climate policy, was used to simulate a sufficiently large and economy wide emissions price to achieve a deep reduction in emissions (Table ES 1). To achieve the target, firms and households must reduce about 780 Mt of greenhouse gas emissions (measured in carbon dioxide equivalent) from the reference case projection emissions of just over 1,000 Mt in 2050, non-inclusive of agriculture, halocarbons, nitric and adipic acid and land use change and forestry. The emissions price pathway modeled does not reflect a policy *per se*; instead it shows the strength of policy required to achieve a deep reduction in emissions.

Table ES 1: Greenhouse gas price simulated in this report ($2005 / tonne CO_2e)

	2011-2015	*2016-2020*	*2021-2025*	*2026-2030*	*2031-2035*	*2036-2040*	*2041-2045*	*2046-2050*
Greenhouse Gas Price	$15	$115	$215	$300	$300	$300	$300	$300

Besides identifying key technologies for deep emissions reductions, this roadmap project also estimates the environmental and economic impacts on individual sectors within the economy associated with this specific roadmap. Impacts include the emission of greenhouse gases, energy consumption, the costs of producing a good or commodity (e.g., cement), the costs of operating a sector (e.g., household), changes in output and the level of capital investment required by the sector to attain the emissions target for 2020 and 2050.

The technology roadmap described here is highly uncertain, in part because there are often multiple methods of reducing greenhouse gas emissions from a specific sector. For example, passenger vehicles, which require concentrated and storable motive energy to meet power and range requirements, could be fueled by biofuels, hydrogen, or electricity, or a hybrid of electricity and some other fuel. Our analysis, which assumes cellulosic ethanol or biodiesel will become technologically and economically feasible at sufficient supply to meet most transportation demand, projects that biofuels will be the dominant transport fuel in the deep reduction scenario. However, hydrogen or battery vehicles could play the dominant role if unforeseen technology breakthroughs make these technologies more economically competitive, or if they are perceived to be more politically favorable. Similarly, our analysis shows significant emissions reductions from carbon capture and storage in the electricity generation and oil sands upgrading sectors. If there were a breakthrough in large-scale electricity storage, a key challenge to intermittent renewables such as wind, this could change. Another possibility is that a large-scale deployment of nuclear energy could perform a similar role to carbon capture and storage, if deemed to be politically acceptable. These uncertainties are inherent in projecting technology developments decades in the future, but they should not prevent us from forming policy to guide technological development in socially and environmentally responsible directions. Put another way, this roadmap identifies the sectors that must achieve significant transformation (e.g., decarbonization of electricity production and transportation) and provides one scenario of how it may occur (e.g., use of a mix of carbon capture and storage, renewables and some nuclear in electricity, and accelerated adoption of hybrid vehicles and biofuels in transportation).

This summary report first reviews the key emission reduction technology actions in our modeling scenario. It then provides a description of the necessary capital investment by sectors, followed by a summary of key areas for technology research, development and deployment. Finally, we provide a graphic summary of the technology roadmap.

In the following discussion, we outline the key findings for each action to reduce greenhouse gas emissions:

- **Carbon capture and storage** in the upstream oil and gas industry, electricity production and industry.
- **Decarbonization of the transportation sector** through energy efficiency improvements through hybridization and fuel switching to low and zero GHG motive fuels.
- **Electrification of residential and commercial buildings and the industrial sector**, which also requires a decarbonization of the electricity sector through carbon capture and storage, more hydropower, and wide scale use of wind turbines and other renewables. Nuclear is held at its 2005 share of total electricity production by assumption.
- **Energy efficiency in the residential, commercial and industrial sectors**.
- **Controls on process greenhouse gas emissions**, such as reduction of well head venting, flaring and other fugitives in upstream oil and gas; changing of industrial processes, etc.

Carbon capture and storage (325 Mt CO_2e of reductions from reference projection in 2050)

- **Natural gas processing, ammonia production and hydrogen production are likely to be early adopters of carbon capture and storage.** In the medium-term, the first adopters of carbon capture are likely to be in the separation of formation carbon dioxide in natural gas processing, ammonia production in chemical products manufacturing and hydrogen production in oil sands upgrading. Each of these processes is uniquely suitable for carbon capture because their costs of capturing carbon dioxide are relatively low and many plants are situated close to areas with good geologic potential for carbon storage. They produce, or can be easily retrofitted to produce, relatively pure streams of carbon dioxide, and therefore avoid the significant costs of separating carbon dioxide from the other flue gases. By 2030 in the policy scenario, almost all these processes employ carbon capture and storage (see Table ES 2).

Table ES 2: Penetration of carbon capture in ammonia, formation carbon dioxide separation and hydrogen production

	2020	*2030*	*2040*	*2050*
Formation Carbon Dioxide from Natural Gas Processing	100%	100%	100%	100%
Hydrogen Production from Oil Sands Upgrading	91%	98%	100%	100%
Ammonia Production from Chemical Products Manufacturing	67%	93%	98%	99%

- **Most emissions reductions from carbon capture and storage are attained in electricity generation and the oil sands extraction and upgrading sectors.** In the long-run, carbon capture is likely to play the most significant role from combustion sources in the electricity generation and oil sands extraction and upgrading sectors, which are forecasted to emit 167 Mt CO_2e and 172 Mt CO_2e in 2050 in the absence of any mitigation policy, respectively. The adoption of carbon capture from these sources is slower than for sources with relatively pure streams of carbon dioxide for several reasons:
  - Capture from combustion sources is more costly because it requires significant capital and energy expenditures to separate the carbon dioxide from other combustion exhaust gases. Combustion can be designed to produce a relatively pure stream of carbon dioxide (i.e., through burning in a virtually pure oxygen environment with no nitrogen) but this is an expensive departure from current practices. Because the policy's stringency increases over time, some of the investments in carbon capture do not occur until later.
  - Retrofitting existing facilities can also be more costly than new construction.
  - The existing stock of electricity plants, oil sands upgraders and in-situ operators is sufficiently large that it will take many years to retrofit or retire the existing stock.
  - Many electricity plants are in locations without good potential for geological storage, and will require pipelines to transport carbon dioxide. By 2050, generation using carbon capture and storage accounts for 27% of total generation, and the remaining electric capacity is almost completely renewable or nuclear (see Table ES 3). Virtually all oil sands upgraders and most in-situ operations employ carbon capture by the end of the simulation period.

Table ES 3: Penetration of carbon capture from large combustion sources

	2020	*2030*	*2040*	*2050*
Utility Electricity Generation	7%	17%	23%	27%
Oil Sands Upgrading	58%	88%	96%	99%
In-situ	35%	54%	57%	55%

Decarbonization of transportation (235 Mt CO_2e of reductions)

- **Approximately 70% of the emissions reductions from the transportation sector are the result of biofuel consumption.** In most modes of transportation, consumers and the freight industry begin to fuel their vehicles with biodiesel or ethanol instead of refined petroleum products (i.e., gasoline and diesel). In some situations, fuel switching requires adjustments to the engine to use biofuels (e.g., a gasoline engine must be modified to run on fuels with 85% ethanol by volume). In other situations, the biofuel may be a functional substitute for a refined petroleum product (e.g., biodiesel may be manufactured so that it has similar performance to diesel). By 2050, 62% of the passenger vehicle stock and virtually the entire freight fleet are fuelled by renewable fuels (see Table ES 4).

Table ES 4: Penetration of vehicles that consume biofuels

	Renewable fuel share (% of total fuel)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Passenger Vehicles	7%	51%	62%	62%	7%	50%	60%	59%
Freight Trucks	20%	72%	96%	97%	20%	72%	96%	97%

- **The policy accelerates the adoption of hybrid and plug-in hybrid vehicles, which reduces the energy intensity of transportation and increases electricity consumption.** By 2050, hybrid and plug-in hybrid vehicles enjoy close to a full penetration in the market for passenger vehicles (see Table ES 5). Mode switching to public transit and purchasing smaller vehicles also contribute to the improvement in energy efficiency. Improvements in freight transportation occur as a result of the adoption of hybrid trucks as well as mode shifts to rail transport.

Table ES 5: Penetration of hybrid and plug-in hybrid vehicles

	Technology Penetration (% of total Stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Passenger Hybrid	3%	6%	11%	12%	2%	3%	-14%	-29%
Passenger Plug-in Hybrid	13%	69%	83%	83%	12%	60%	67%	65%
Freight Hybrid	3%	32%	59%	62%	2%	26%	15%	0%

- **The expansion of biofuel and electricity consumption requires increased production of biofuels and electricity.** The increases in ethanol and biodiesel consumption require a substantial increase in the production of biofuels. In order to meet the demand for biofuels, production is forecasted to expand from negligible levels in 2005 to over 2,000 PJ by 2050. The sector must also reduce its greenhouse gas intensity and produce biofuels in a manner that does not put politically unsustainable pressure on agroecosystems or food prices. In this forecast, most ethanol production is from waste and woody biomass using cellulosic ethanol processes, and carbon capture and storage is used at biofuel manufacturing plants. The expansion of the electricity sector is discussed in the following section.

Electricicification of buildings and industry (75 Mt CO_2e of reductions)

- **Many sectors throughout the economy substitute away from direct use of fossil fuels and use more electricity to reduce their direct greenhouse gas emissions.** The share of electricity among total energy consumption increases as key sectors reduce emissions by switching to electricity (see Table ES 6). In the residential and commercial sectors, the policy causes an increase in the adoption of ground source heat pumps and electric baseboards for space heating; in the transportation sector, the share of plug-in hybrid vehicles among passenger vehicles expands considerably; in the manufacturing sectors, electricity can be used to produce heat, steam and hot water.

Table ES 6: Electricity share of total energy consumption

	Electricity fuel share (%)				*Increase in electricity share due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Residential	68%	87%	94%	97%	20%	35%	36%	32%
Commercial	57%	69%	77%	79%	12%	24%	33%	35%
Other Manufacturing	48%	65%	75%	78%	21%	38%	47%	50%

- **The increase in electricity demand requires a significant expansion of the electricity sector.** Similar to the biofuels, the increased demand for electricity requires a considerable expansion of electric capacity while reducing the greenhouse gas intensity of the sector. In 2050, electricity generation in the policy scenario is 1,700 TWh – 50% greater than the reference projection. Reducing the greenhouse gas intensity of the electricity sector presents unique challenges to each province. Provinces without significant hydroelectric potential – particularly Alberta and Saskatchewan – show an expansion of electricity generated using carbon capture and storage. Provinces with better hydroelectric potential employ considerable expansions of hydroelectric generation. Table ES 7 illustrates electric generation by different systems, and the increase above the reference case projection.

Table ES 7: Electric generation in the policy scenario

	Electric Generation (TWh)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Renewable	544	703	860	1,013	20%	36%	42%	43%
Nuclear	124	168	204	232	25%	54%	64%	57%
Coal w/o CCS	112	86	43	5	4%	-30%	-71%	-98%
Natural Gas w/o CCS	26	15	9	6	-29%	-65%	-81%	-89%
Carbon Capture & Storage	62	193	328	456	NA	NA	NA	NA

Note: There is minimal penetration of carbon capture and storage in the reference case, so we do not show an increase over the reference case.

- **The expansion of electricity generated from renewables reduces greenhouse gas emissions at the point of electricity consumption.** The analysis shows a considerable increase in electricity generated from renewable sources, but it does not show significant emissions reductions in the electricity sector from switching to renewables. Most of the new capacity to generate electricity from renewables is added in provinces where generation is already dependent on renewables, and does not have a significant impact on emissions at the point of electric generation. However, the expansion of generation from renewables in these provinces enables other sectors, such as the residential and commercial sectors, to increase electricity consumption and reduce their consumption of fossil fuels.

Energy efficiency improvements in buildings and industry (20 Mt CO_2e of reductions)

- **Most improvements to energy efficiency, outside transportation, occur in the residential and commercial sectors.** Most reductions from energy efficiency improvements in the commercial and residential sectors are from investments in ground source heat pumps. Improvements to building shells lead to modest emissions reductions.
- **The energy efficiency improvements in the industrial and energy supply sectors are mostly offset due to the adoption of carbon capture and storage.** Carbon capture requires more energy than an equivalent facility without, so most of the sectors which abate their emissions using carbon capture and storage show increases in energy intensity.

Controls on process greenhouse gas emissions (55 Mt CO_2e of reductions)

- **Capturing and flaring landfill gas is likely to be an early opportunity to reduce greenhouse gas emissions.** The cost of capturing and flaring landfill gas is relatively low and the policy is likely to induce all landfills to capture and flare landfill gas by 2020. In 2020, the waste sector reduces emissions by 25 Mt CO_2e from the reference case projection, and by 2050 the reduction reaches 30 Mt CO_2e.
- **Reduced and managed well venting and flaring, testing, and leak detection and repair programs can reduce fugitive emissions from the natural gas and crude oil extraction sectors.** By 2050, these actions account for approximately 19 Mt CO_2e of emissions reductions from the reference projection.

Capital expenditures required to meet the deep reduction target

In order to attain a 65% reduction in greenhouse gas emissions from 2006 levels by 2050, the level of capital expenditure rises by 5% – 6.4 billion per year ($2005) – from the reference case projection in the medium-term, and by 3% in the long-term (6.0 billion per year) (see Table ES 10). However, numbers mask very large sectoral differences (Table ES 10), and large differences in focused costs and diffuse benefits.

Table ES 10: Increase in annual capital expenditures caused by policy (2005$ millions)

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Demand Sectors		
Residential	41	-117
Commercial	-136	642
Transportation	-8,414	-6,892
Manufacturing Industry	-228	-322
Landfills	70	19
Supply Sectors		
Electricity	12,512	9,554
Fossil Fuel Extraction & Refining	1,054	496
Biofuel Manufacturing	1,519	2,637
Total	6,418	6,018

The effects on individual sectors are radically different, especially between the transport, electricity and other energy supply sectors. In passenger transportation, capital expenditures fall as people purchase smaller vehicles, travel less, and use public transit more. Expenditures in freight transport decline due to an increase in rail transport, and a decline in total freight transport. Expenditures by the electricity sector increase by an average of $11 billion per year ($2005) to expand generation and to finance efforts to decarbonize production. Capital expenditures in the fossil fuel extraction and biofuel sectors also increase markedly, mainly for carbon capture and storage for the former, and increased output and decarbonization for the latter.

Summary of actions to reduce greenhouse gas emissions

Table ES 8 summarizes the emissions reductions from key actions to reduce direct greenhouse gas emissions (i.e., at the point of emission). As discussed above, the expansion of biofuels and electricity production in some provinces does not significantly reduce emissions at the point of greenhouse gas emissions, but enables emissions reductions at the point of energy consumption (e.g., an increase in the production of hydroelectricity in Québec enables the residential sector to reduce natural gas consumption).

Table ES 8: Summary of direct emissions reductions by action (Mt CO_2e)

	2020	2030	2040	2050
Carbon Capture and Storage	**94**	**183**	**259**	**325**
Formation Carbon Dioxide from Natural Gas Processing	6	6	5	5
Hydrogen Production from Oil Sands Upgrading	11	13	14	15
Ammonia Production from Chemical Products Manufacturing	2	3	4	4
Utility Electricity Generation	28	75	114	154
Oil Sands Upgrading	33	53	70	76
In-situ Bitumen Extraction	8	16	22	29
Other Carbon Capture and Storage	5	17	30	41
Energy Efficiency & Carbon Capture Overlap	**11**	**20**	**29**	**37**
Decarbonization of Transportation	**60**	**156**	**208**	**235**
Biofuel Consumption for Transportation	16	88	147	175
Electricity Consumption for Transportation	2	17	23	25
Reduced Energy Consumption from Hybrid Vehicles [a]	28	41	31	29
Mode switching to Public Transit and Rail Freight Transport [a]	12	13	9	9
Decline in Petroleum Refining	6	14	17	16
Increased Biofuel and Electricity Production for Transportation	-4	-16	-19	-18
Electrification of Buildings and Industry	**3**	**26**	**53**	**75**
Electric Space and Water Heating in Buildings	21	43	57	65
Increased Electricity use in Other Manufacturing	8	17	26	34
Fuel Switching to Electricity in Other Industrial Sectors	6	12	19	23
Increased Electricity Generation for Buildings and Industry	-32	-46	-49	-46
Energy Efficiency in Residential, Commercial and Industry	**10**	**16**	**20**	**22**
Ground Source Heat Pumps in Buildings [a]	6	10	13	14
Improvements to Residential and Commercial Shells [a]	1	2	3	3
Other Improvements to Energy Efficiency	4	4	4	5
Controls on Process Greenhouse Gas Emissions	**53**	**55**	**54**	**53**
Landfill Gas Cap and Flare	26	27	28	28
Reduced Venting and Flaring in Upstream Oil & Gas [a]	20	19	18	16
Leak Detection and Repair in Upstream Oil & Gas [a]	3	3	3	3
Other Controls	4	5	5	5
Changes in Sector Output	**16**	**17**	**14**	**15**
Decline in Industrial Output	5	8	8	8
Decline in Transportation Demand	11	9	6	7
Other Actions	**3**	**6**	**12**	**17**
Total Reductions in Greenhouse Gas Emissions from all Actions	**250**	**480**	**648**	**779**

Notes: [a] Value is approximate.

Table ES 9 shows the emissions reductions enabled by the expansion of different methods for producing electricity and renewable fuels.

Table ES 9: Emissions reductions enabled by the expansion of the electricity and biofuels sectors (Mt CO_2e)

	2020	*2030*	*2040*	*2050*
Clean Electricity Generation	**37**	**89**	**125**	**146**
Generation from Renewables	20	39	50	54
Generation from Nuclear	5	12	15	15
Generation using Carbon Capture and Storage	12	38	60	77
Biofuel Production	**16**	**88**	**147**	**175**
Cellulosic Ethanol Production	8	52	63	55
Biofuel Production with Carbon Capture and Storage	3	19	47	73
Other Biofuel Production Methods [a]	4	17	37	47
Total Reductions from Expansion of Clean Energy Production	**53**	**177**	**272**	**321**

Notes: [a] Includes production methods that use electricity or renewable fuels to produce the heat necessary for biofuel production.

Table ES 10 shows the reduction in greenhouse gas emissions from the reference projection (e.g., greenhouse gas emissions in the residential sector are 36 Mt CO_2e lower in the policy scenario in 2050 than in the reference scenario in 2050). Emissions reductions are likely to be concentrated in the transportation, electricity generation and petroleum production sectors, which are forecasted to contribute to the majority of Canada's greenhouse gas emissions in the absence of a policy. Together, these sectors account for around 70% of Canada's total reductions. The landfill and natural gas sectors play an important role in the medium-term, because of potential early opportunities to reduce emissions from landfills and captured formation carbon dioxide.

Table ES 10: Reductions in greenhouse gas emissions from reference case by sector

	Emissions Reductions (Mt CO_2e)			
	2020	*2030*	*2040*	*2050*
Demand Sectors				
Residential	18	32	36	36
Commercial	12	25	38	47
Transportation	70	169	216	244
Manufacturing Industry	27	55	78	98
Landfills	26	27	28	29
Supply Sectors				
Electricity	-2	29	74	128
Fossil Fuel Extraction & Refining	100	146	183	203
Biofuel Manufacturing	-1	-4	-5	-6
Total	250	480	648	779

Total energy consumption in the Canadian economy increases – by 10% in 2050 – in response to the policy. Energy consumption rises, mostly due to an increase in output from the electricity and biofuels production sectors, but also due to greater energy requirements associated with carbon capture. Energy consumption declines in most other sectors of the economy (although energy consumption rises in some sub-sectors of manufacturing industry and fossil fuel extraction and refining).

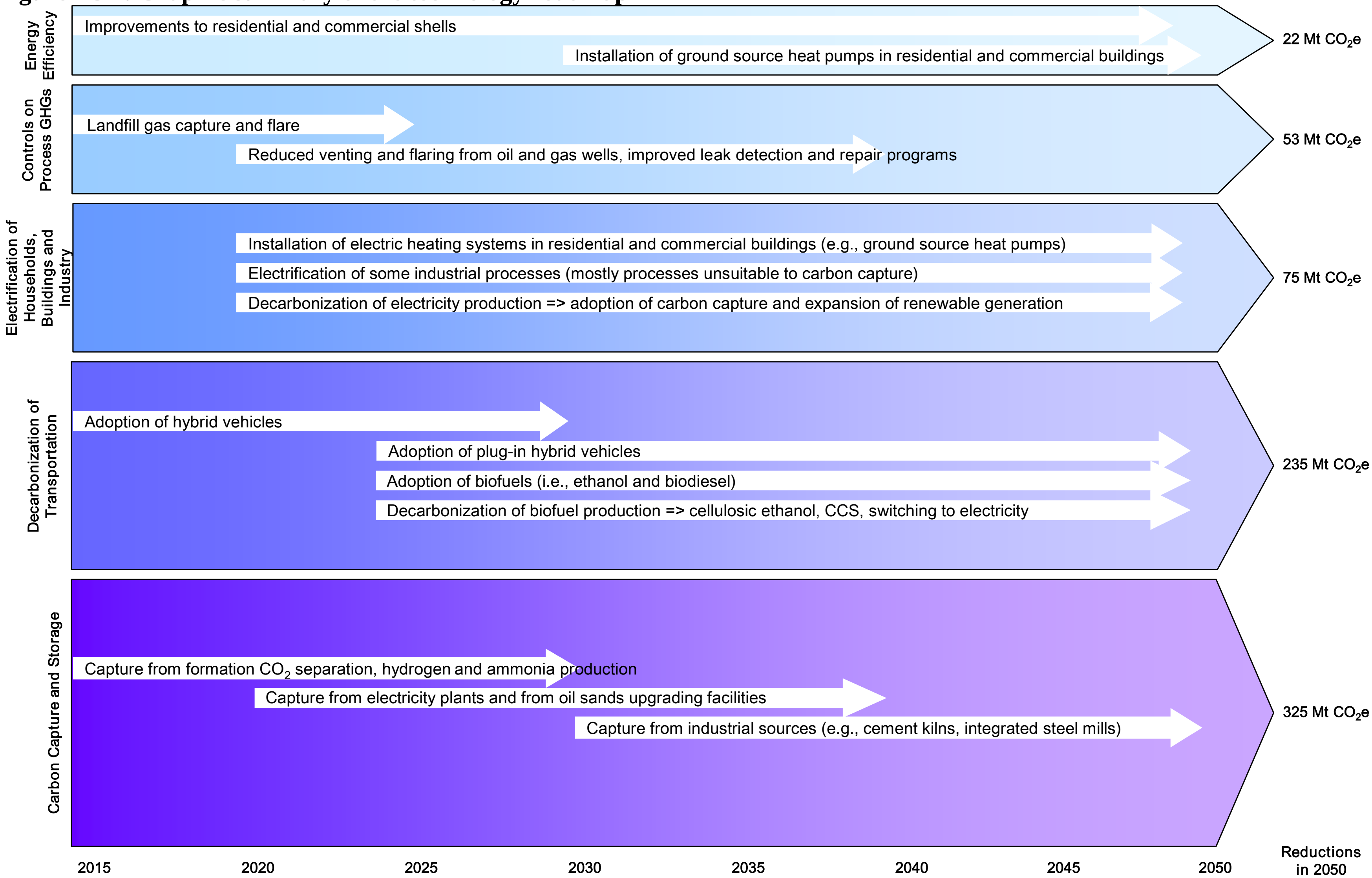
Table ES 11: Reductions in energy consumption from the reference case by sector

	Reduction in Energy Consumption (PJ)			
	2020	*2030*	*2040*	*2050*
Demand Sectors				
Residential	182	331	402	435
Commercial	159	323	511	650
Transportation	724	1,172	1,085	1,137
Manufacturing Industry	158	186	174	182
Landfills	11	14	16	17
Supply Sectors				
Electricity	-1,144	-2,618	-3,692	-4,394
Fossil Fuel Extraction & Refining	21	64	47	49
Biofuel Manufacturing	-37	-152	-269	-325
Total	73	-679	-1,728	-2,249

Graphic summary of the technology roadmap

Figure ES 1 highlights the key technologies and actions that contribute to the emissions reductions from the Canadian economy between 2015 and 2050. The arrow for each technology action (e.g., carbon capture from electricity and oil sands plants) indicates the period during which the technology begins to play a dominant role in the reductions and when it attains its maximum penetration. For example, the adoption of carbon capture at electricity and oil sands facilities begins around 2020, and most of these plants employ carbon capture by 2040. The adoption of carbon capture at smaller industrial facilities becomes significant later in the simulation.

Figure ES 1: Graphic summary of the technology roadmap



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Introduction

In *Getting to 2050: Canada's transition to a low emissions future,* the National Round Table on the Environment and the Economy (NRTEE) estimated the strength of policy that would be necessary to attain deep reductions in greenhouse gas emissions by 2050 (a 65% reduction from 2006 levels by 2050). The NRTEE retained J & C Nyboer and Associates to expand on the previous study to 1) assess the sectoral and regional implications of attaining deep reductions in greenhouse gas emissions, and 2) develop a technology roadmap that forecasts the technological developments that occur in order to attain these reductions. The technology roadmap identifies key technologies or their components for getting to this goal, the order in which they need to be achieved, and the required investment necessary for each step. It also shows which technologies may support the advancement of other sub-goals within the roadmap.

The purpose of this study is to forecast technological developments, rather than prescribe the technological developments that must occur to attain a deep reduction in greenhouse gas emissions. The forecast is highly uncertain, in part because there are often multiple methods of reducing greenhouse gas emissions from a specific sector. For example, passenger vehicles may be fueled with biofuels or hydrogen, neither of which produce net greenhouse gas emissions at the point of combustion. Our analysis shows that biofuels play a dominant role in the emissions abatement from the transportation sector, but hydrogen may play a dominant role if it is perceived to be more economically or politically favorable. Similarly, our analysis shows significant emissions reductions from carbon capture and storage in the electricity generation and oil sands upgrading sectors. However, nuclear energy could attain similar emissions reductions if it is deemed to be politically acceptable.

J & C Nyboer and Associates uses a detailed energy-economy model called CIMS to evaluate energy and climate change policies and to determine the cost of reducing greenhouse gas emissions. In this project, we use the CIMS model to estimate the technological developments that occur in response to a price on greenhouse gas emissions that achieves the deep reduction in greenhouse gas emissions described in *Getting to 2050*. We estimate these developments at sectoral and provincial levels in order to forecast how each sector and region will be affected by the policy. As part of the analysis, we highlight the sectors of the economy that contribute most significantly to the emission or abatement of greenhouse gas emissions. The report is accompanied with an appendix and spreadsheet that show most of the data used to develop the report.

Structure of this report

We begin this report with an overview of the methodology used to produce the quantitative results, including a general description of the CIMS model that was used for the analysis. We then discuss the assumptions and inputs used to develop the reference case forecast, and present the reference case forecast in detail. The following section presents the sectoral and regional implications of deep reductions in greenhouse gas emissions, and forecasts the technological developments that occur to reach these reductions.

Methodology

The primary objective of this study is to forecast technological developments that occur for Canada to attain deep reductions in greenhouse gas emissions by 2050. A deep reduction in greenhouse gas emissions is defined as a 20% reduction from 2006 levels by 2020 and a 65% reduction by 2050. To conduct the analysis, the CIMS energy-economy model was updated to reflect recent national data and trends, and used to forecast the developments that occur in response to a price on greenhouse gas emissions. The model is described very briefly here; a somewhat more comprehensive description of the model is provided in the Appendix B.

The CIMS model

The CIMS model, developed by the Energy and Materials Research Group at Simon Fraser University and by J & C Nyboer and Associates, simulates the technological evolution of fixed capital stocks (such as buildings, vehicles, and equipment) and the resulting effect on costs, energy use, emissions, and other material flows. The stock of capital is tracked in terms of energy service provided (m^2 of lighting or space heating) or units of physical product (metric tons of market pulp or steel). New capital stocks are acquired as a result of time-dependent retirement of existing stocks and growth in stock demand. Market shares of technologies competing to meet new stock demands are determined by standard financial factors as well as behavioral parameters from empirical research on consumer and business technology preferences. CIMS has three modules — energy supply, energy demand, and macro-economy — which can be simulated as an integrated model or individually. A model simulation comprises the following basic steps.

1. A base-case macroeconomic forecast initiates model runs. The macroeconomic forecast is at a sectoral or sub-sectoral level (for example, it estimates the growth in total passenger travel demand, or in airline passenger travel demand). The macroeconomic forecast adopted for this study is described in detail in the following section.
2. In each time period, some portion of existing capital stock is retired according to stock lifespan data. Retirement is time-dependent, but sectoral decline can also trigger retirement of some stocks before the end of their natural life spans. The output of the remaining capital stocks is subtracted from the forecast energy service or product demand to determine the demand for new stocks in each time period.
3. Prospective technologies compete for new capital stock requirements based on financial considerations (capital cost, operating cost), technological considerations (fuel consumption, lifespan), and consumer preferences (perception of risk, status, comfort), as revealed by behavioral-preference research. The model allows both firms and individuals to project future greenhouse gas prices with imperfect foresight when choosing between new technologies (somewhere between total

myopia and perfect foresight about the future). Market shares are a probabilistic consequence of these various attributes.

4. A competition also occurs to determine whether technologies will be retrofitted or prematurely retired. This is based on the same type of considerations as the competition for new technologies.

5. The model iterates between the macro-economy, energy supply and energy demand modules in each time period until equilibrium is attained, meaning that energy prices, energy demand and product demand are no longer adjusting to changes in each other. Once the final stocks are determined, the model sums energy use, changes in costs, emissions, capital stocks and other relevant outputs.

The key market-share competition in CIMS can be modified by various features depending on the evidence about factors that influence technology choices. Technologies can be included or excluded at different time periods. Minimum and maximum market shares can be set. The financial costs of new technologies can decline as a function of market penetration, reflecting economies of learning and economies of scale. Intangible factors in consumer preferences for new technologies can change to reflect growing familiarity and lower risks as a function of market penetration.

Personal mobility provides an example of CIMS' operation. The future demand for personal mobility is forecast for a simulation of, say, 30 years and provided to the energy demand module. After the first five years, existing stocks of personal vehicles are retired because of age. The difference between forecast demand for personal mobility and the remaining vehicle stocks to provide it determines the need for new stocks. Competition among alternative vehicle types (high and low efficiency gasoline, natural gas, electric, gasoline-electric hybrid, and eventually hydrogen fuel-cell) and even among alternative mobility modes (single occupancy vehicle, high occupancy vehicle, public transit, cycling and walking) determines technology market shares. The results from personal mobility and all other energy services determine the demand for fuels. Simulation of the energy supply module, in a similar manner, determines new energy prices, which are sent back to the energy demand module. The new prices may cause significant changes in the technology competitions. The models iterate until quantity and price changes are minimal, and then pass this information to the macro-economic module. A change from energy supply and demand in the cost of providing personal mobility may change the demand for personal mobility. This information will be passed back to the energy demand module, replacing the initial forecast for personal mobility demand. Only when the model has achieved minimal changes in quantities and prices does it stop iterating and move on to the next five-year time period.

Model limitations and uncertainties

Like all models, CIMS is a representation of the real world, and so does not represent it perfectly. Even though CIMS is very detailed compared to other models used for similar purposes, its broad scope (it represents all energy consumption throughout the economy) requires many simplifying assumptions. Main uncertainties and limitations in the model are:

- **Technological detail and dynamics –** CIMS contains considerable technological detail in each of its sectoral sub-models. This detail enables CIMS to show accelerated market penetration of alternative technologies in response to an energy or climate change policy and ensure that reference and policy scenarios are grounded in technological and economic reality. While care has been taken in representing the engineering and economic parameters of the many technologies in CIMS, uncertainty exists (particularly in industrial sectors) as to the appropriate cost and operating parameters of specific technologies.

  This uncertainty becomes larger over time. While CIMS contains a representation of dynamic technological change that depicts how the costs of new technologies can be reduced through economies of scale and production experience based on historical experience, there is no guarantee that these relationships will hold in the future. In addition, CIMS only contains technological options that are known today (including those that are not yet commercialized). By definition, CIMS does not contain a depiction of new technologies that have not yet been invented. As a result, CIMS could miss technological substitution options in later years of the forecast.

- **Behavioral realism –** The technology choice algorithm of CIMS takes into account implicit discount rates revealed by real-world technology acquisition behavior, intangible costs that reflect consumer and business preferences, and heterogeneity in the marketplace. Incorporating behavioral realism is critical in order to predict realistic consumer and firm response to policies, however, incorporating preferences at a detailed level into a model that is technologically explicit is challenging. In addition to the sheer volume of the data requirements, the non-financial preferences of consumers and firms are difficult to estimate, and can change over time. The complexities associated with estimating behavioral parameters, combined with the fact that information cannot be collected for all the technology competitions in CIMS, result in a high degree of uncertainty associated with these parameters overall. The potential for preference change is also a key uncertainty.

- **Equilibrium feedbacks -** Unlike most computable general equilibrium models (which do not contain technological detail), the current version of CIMS does not equilibrate government budgets and the markets for employment and investment. Also, its representation of the economy's inputs and outputs is skewed toward energy supply, energy intensive industries, and key energy end-uses in the residential, commercial/institutional, and transportation sectors. As a result, it is likely to underestimate the full structural response of the economy to energy and climate change policies.

- **External inputs –** CIMS requires external forecasts of macroeconomic activity in each sub-sector, population growth forecasts, and fuel price forecasts on which to base the analysis. These forecasts are uncertain and could affect the results of the simulations. In addition, since no individual forecast is available to provide all key inputs over the period of interest in this analysis, we have adopted inputs from several different sources. We have used respected sources, and attempted to ensure consistency between various sources, but it is likely that the various inputs we use are not perfectly consistent with one another.

Modelling scenario

In order to determine the greenhouse gas abatement opportunities in Canada, we use the concept of a reference scenario and a policy scenario. The reference scenario shows how the Canadian economy might evolve in the absence of specific new policies to reduce greenhouse gas emissions. The policy scenario shows how the economy might evolve under a given policy. The difference between the two scenarios is due to the effect of the policy.

In this report, we use an economy-wide price on greenhouse gas emissions to simulate deep reductions in greenhouse gas emissions – a 20% reduction from 2006 levels by 2020, and a 65% reduction by 2050. The emissions price pathway modeled in this analysis (See Table 1) does not reflect policies *per se*; instead it captures the strength of a market-based policy signal required to achieve a given level of emissions reductions.

The emissions price pathway modeled in this report is slightly lower than the pathway modeled in *Getting to 2050*, which showed an emissions price rising to $330 / tonne CO_2e (2005$) in order to attain deep reductions in emissions. Several modifications have been made to the CIMS model between the two contracts, and are discussed in the following section.

Table 1: Greenhouse gas price ($2005 / tonne CO_2e)

	2011-2015	*2016-2020*	*2021-2025*	*2026-2030*	*2031-2035*	*2036-2040*	*2041-2045*	*2046-2050*
Greenhouse Gas Price	$15	$115	$215	$300	$300	$300	$300	$300

The reference scenario

The reference scenario described in this report is based on several external inputs showing how the economy will evolve over the coming 42 years to 2050. Many key inputs underlying the reference scenario are highly uncertain, and if the economy evolves differently than as shown in this reference scenario, energy consumption and emissions will also differ from what we show here. We have used credible sources to guide key inputs wherever possible, but no amount of research allows perfect foresight into the future of the economy. As a result, the scenario described here should be considered just one possible reference scenario. We consider it a good "business as usual" forecast, based on historic trends and research into likely future technological and economic evolution, but the uncertainty remains large. We begin by highlighting our key assumptions, and follow by showing the results of our forecast.

Key economic drivers and assumptions

CIMS uses an external forecast for the economic or physical output of each economic sector to develop the business as usual forecast. For example, CIMS requires an external forecast for the number of residential households, and another for the amount of cement produced in the province. These forecasts can be internally adjusted when a policy is applied. We discuss the forecasts adopted for both the energy supply sectors and the energy demand sectors.

Energy demand sectors

For all energy demand sectors, the external forecast through 2020 is based on the same data used by Natural Resources Canada to develop the national energy outlook in 2006.[1] For years beyond 2020, the forecast for demand sectors is based on a long-run economic forecast of gross domestic product, population, and labor force participation prepared by Informetrica for the federal government, which is depicted in Table 2.[2] The population forecast used here is based on the medium growth scenario developed by Statistics Canada in a recent demographic forecast.[3]

Table 2: Canada's economic and demographic forecast

	Units	*2010*	*2020*	*2030*	*2040*	*2050*
Population	*Thousands*	33,639	36,344	38,812	40,644	41,896
Gross Domestic Product	*billion 2005$* [a]	1,460	1,827	2,194	2,652	3,153

Note: [a] Gross domestic product is presented in basic prices

1 Natural Resources Canada, 2006, "Canada's Energy Outlook: The Reference Case 2006", Analysis and Modelling Division, Natural Resources Canada.

2 Infometrica, 2007, "Infometrica's Long-run Reference Population and Productivity Forecast". Natural Resources Canada also bases its forecast on Infometrica's macroeconomic and demographic projections.

3 Statistics Canada, 2006, "Population Projections for Canada, Provinces, and Territories: 2005-2031", Demography Division, Statistics Canada.

The residential sector is anticipated to grow rapidly because of continued population growth. The rates of both population growth and household formation are expected to slow later in the forecast, when Canada's population is anticipated to be about 25% larger than the current level.

The commercial sector is expected to undergo rapid expansion, driven by expanding economic output. By the end of the forecast period, the commercial sector is expected to be more than double its current size (based on physical building footprint).

Travel demand in the passenger transportation sector increases quickly in Canada, fuelled by growth in population as well as income. These trends are expected to continue in general, but slow throughout the forecast period. In the freight transportation sector, growth is based on gross domestic product and expansion of industrial output, which expand rapidly in the reference case.

Like other demand sectors, output is expected to grow in the industrial manufacturing sector. The output from the other manufacturing sector grows the most rapidly, while growth in other sectors is more muted.

Energy supply sectors

The main energy supply sectors in CIMS include crude oil extraction, natural gas extraction and processing, petroleum refining, electricity generation, coal mining and biofuels manufacturing. For crude oil and natural gas, we rely on external forecasts of production because a large percentage of Canada's production is exported to other regions. For petroleum refining, electricity generation, and coal mining, we base the supply forecast on Canada's projected energy demand and add in an external forecast of net exports of each commodity to calculate total production.

Canada's crude oil production forecast (Figure 1) is based on the moderate growth case of the Canadian Association of Petroleum Producers 2007 report.[4] Between 2025 and 2050, the output of conventional crude oil (light/medium and heavy) is projected to continue to decline due to existing reserve depletion. By 2050, conventional crude oil production is expected to account for only a small amount of total production.

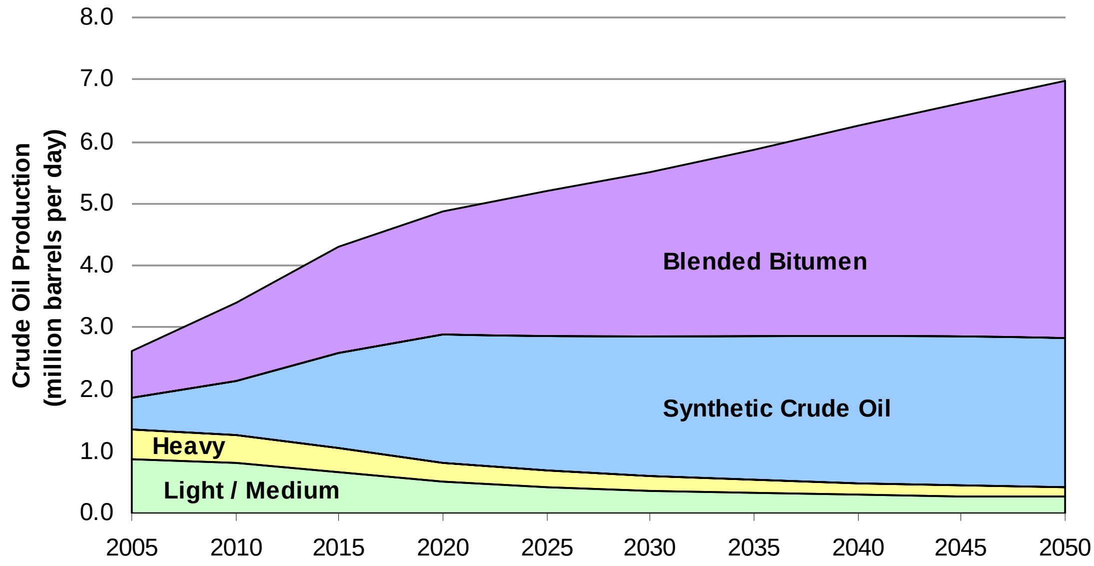
Conversely, production of unconventional crude oil, from Alberta's oil sands, is forecast to increase dramatically during the forecast period. Total production of unconventional crude oil is expected to reach about 4.5 million barrels per day by 2025 and nearly 6.6 million barrels per day by 2050, a five-fold expansion in capacity from today's levels. Particularly rapid growth in the industry is expected in the coming two decades, both in blended bitumen operations and in synthetic crude oil operations.

According to the Alberta Energy and Utilities Board, the volume of crude bitumen in the oil sands is approximately 1.6 trillion barrels, with 175 billion barrels recoverable under current economic conditions and with existing technologies. The growth forecast of oil

[4] Canadian Assocation of Petroleum Producers, 2007, "Crude oil forecast, markets, and pipeline expansions", June 2007. CAPP's forecast extends to 2025; after 2025, production in the sector is assumed to continue to grow for unconventional crude oil, and to continue to decline for conventional crude oil. The forecast after 2025 is very uncertain since projects are not announced with this much lead-time. CAPP's recent forecast is higher than the forecast adopted in NRCan's 2006 Energy Outlook.

sands development in our model has taken this resource constraint into consideration. During the modeling period, the forecasted cumulative output of blended bitumen and synthetic crude oil in Canada is about 73 billion barrels.

Figure 1: Crude oil supply forecast



Source: Forecast based on Moderate Growth case from Canadian Association of Petroleum Producers, 2007, "Crude oil forecast, markets, and pipeline expansions".

Marketable natural gas production in Canada between 2000 and 2020 is grounded in Natural Resources Canada's CEO 2006, but modified to reflect history and more recent material from the Canadian Association of Petroleum Producers and the Alberta Energy and Utility Board's 2006 forecast. The growth rate forecast between 2015 and 2025 comes from a recent National Energy Board report.[5] Key recent changes include the delay of large-scale production of Arctic gas, transmitted via the Mackenzie Valley, until after 2013, higher estimates of accessible coal bed methane, and increased optimism about replacement of reserves from the Western Canadian Sedimentary Basin, which underlies BC, the Northwest Territories, Alberta, Saskatchewan and Manitoba. While much of the accessible and inexpensive conventional gas reserves have been depleted, drilling technology (e.g., side and angle drilling and search software) and the ability to access tight gas have improved such that larger than previously expected additions to reserves are expected up to 2015.

The forecast of marketable natural gas production adopted for this report peaks near 2015 and then begins to decline fairly quickly, even with a substantial increase in coal bed methane supply (see Figure 2). Because coal bed methane is a relatively new resource,

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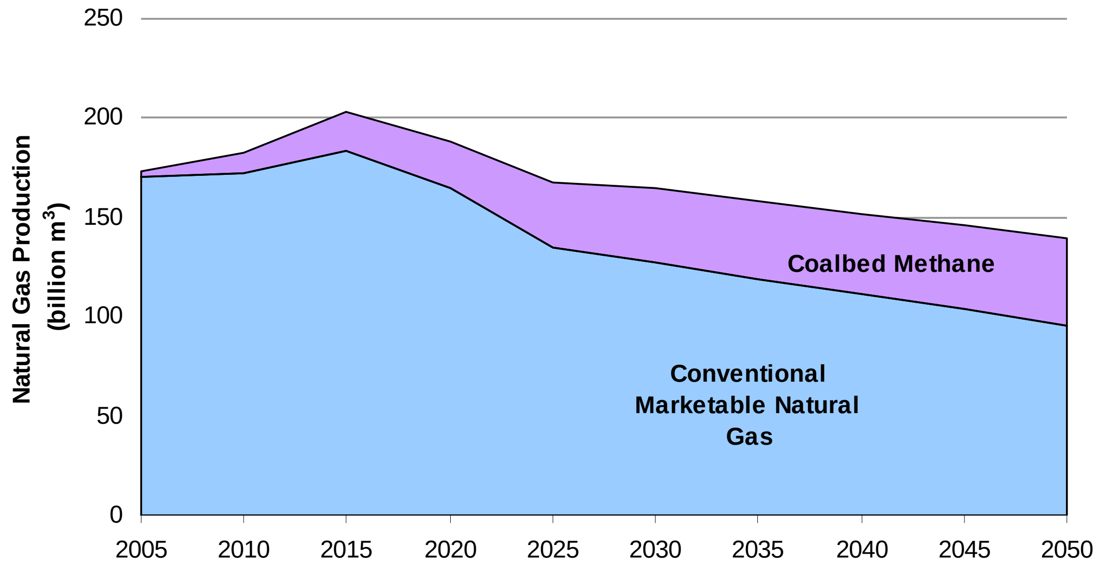
[5] Alberta Energy Utilities Board, 2006, "Alberta's Energy Reserves 2005" and "Supply/Demand Outlook 2006-2015"; National Energy Board, 2003, "Canada's Energy Future: Supply and Demand Forecast to 2025"; National Energy Board, 2004, "Canada's Oil Sands: Challenges and Opportunities to 2015".

the forecast for extraction of coal bed methane adopted for this reference scenario is very uncertain.

Figure 2: Natural gas supply forecast



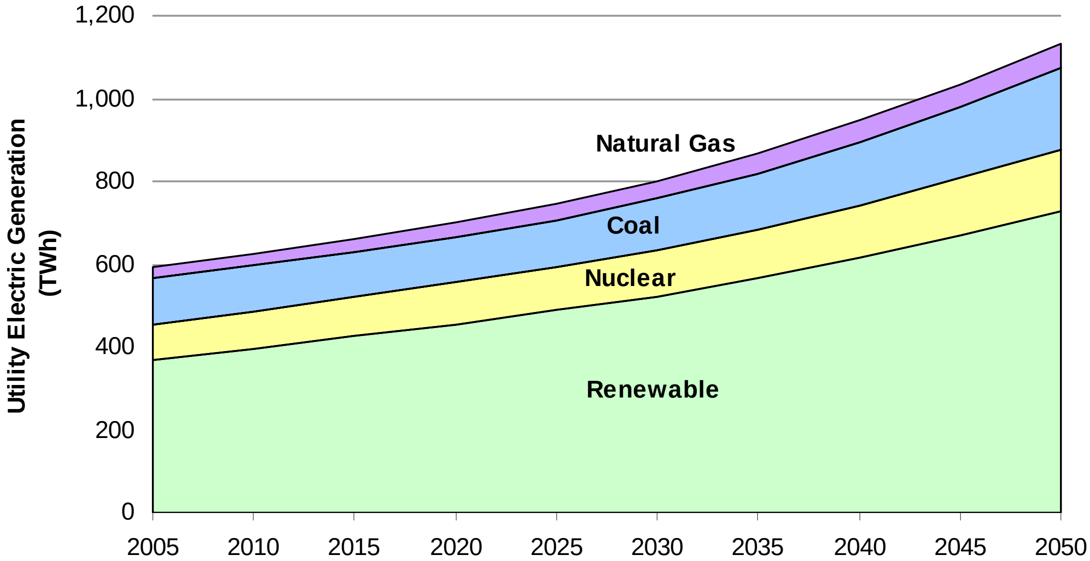
Source: Forecast based on Natural Resources Canada, “Canada’s Energy Outlook 2006”; Alberta Energy Utilities Board, “Alberta’s Energy Reserves 2005” and “Supply/Demand Outlook 2006-2015”; National Energy Board, 2007, “Canada’s Energy Future: Supply and Demand Forecast to 2030” and National Energy Board, 2004, “Canada’s Oil Sands: Challenges and Opportunities to 2015”.

The forecast of output for the electricity generation sector is based on the calculated demand from all other sectors in the model, and is adjusted to include net exports of electricity.[6] It does not include non-utility electricity generation, which is accounted for separately in the other sub-models (for example, electricity production by cogeneration in the oil sands is accounted for in the upstream oil sub-model).

The fuel source for electric generation varies considerably between provinces. British Columbia, Manitoba and Québec, have abundant hydroelectric potential, and most capacity additions until 2050 are forecasted to be hydroelectric. Ontario and the Atlantic provinces have a mixture of hydroelectric, nuclear and fossil fuel generation; while Alberta and Saskatchewan rely primarily on coal and natural gas to generate electricity. Figure 3 shows the reference case electricity generation by fuel type for Canada; generation by province is available in the appendix.

[6] Net exports of electricity are based on the recent Natural Resources Canada energy outlook through 2020 and are assumed to remain at historic levels thereafter.

Figure 3: Reference case utility electricity generation by fuel type



In the policy scenario, we assume that net exports of electricity and coal remain fixed at the levels in the reference case. For crude oil and natural gas in the policy scenarios, we assume that total provincial production of the commodity is fixed and adjust net exports based on the difference between total production and domestic demand. Although this assumption is likely imperfect, the US Energy Information Administration projects that international demand for crude oil and natural gas is likely to remain robust even with the introduction of climate change abatement policies.[7]

As has been emphasized throughout, the economic output forecast adopted here (see Table 5) reflects historic and anticipated future trends, but is highly uncertain, particularly in the later years of the forecast.

[7] Energy Information Administration, 1998, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity", United States Department of Energy.

Table 3: Reference case output forecast

	Units	2010	2020	2030	2040	2050
Demand Sectors						
Residential	*thousands of households*	13,545	15,222	16,566	17,253	17,815
Commercial	*million m^2 of floorspace*	729	911	1,091	1,316	1,561
Transportation						
Passenger	*billion passenger-km*	742	944	1,152	1,339	1,493
Freight	*billion tonne-km*	966	1,198	1,420	1,689	1,987
Manufacturing Industry						
Chemical Products	*million tonnes* [a]	19	22	24	27	30
Industrial Minerals	*million tonnes* [b]	18	21	25	29	33
Iron and Steel	*million tonnes*	15	16	18	20	22
Metal Smelting	*million tonnes* [c]	5	5	5	5	5
Mineral Mining	*million tonnes*	262	274	282	292	304
Pulp and Paper	*million tonnes* [d]	20	22	24	26	27
Other Manufacturing	*billion $2005*	205	260	318	391	472
Supply Sectors						
Electricity Generation	*TWh*	625	701	802	947	1,133
Petroleum Refining	*million m^3*	101	115	117	124	136
Crude Oil						
Conventional Light	*thousand barrels per day*	823	502	365	295	257
Conventional Heavy	*thousand barrels per day*	438	322	238	186	151
Synthetic Crude	*thousand barrels per day*	878	2,075	2,249	2,375	2,418
Blended bitumen	*thousand barrels per day*	1,244	1,967	2,663	3,396	4,160
Natural Gas	*billion m^3* [e]	179	179	149	135	121
Coal Mining	*million tonnes*	72	87	92	97	106
Biofuels Manufacturing	*PJ*	9	16	31	65	103

Notes: [a] chemical product output is the sum of chlor-alkali, sodium chlorate, hydrogen peroxide, ammonia, methanol, and petrochemical production
[b] industrial mineral output is the sum of cement, lime, glass, and brick production
[c] metal smelting output is the sum of aluminium, copper, lead, magnesium, nickel, titanium and zinc smelting
[d] pulp and paper output is the sum of linerboard, newsprint, coated and uncoated paper, tissue and market pulp production
[e] natural gas production includes coalbed methane

Energy prices

CIMS requires an external forecast for energy prices. As for sectoral output, fuel prices can change while a policy scenario is running if the policy induces changes in the cost of fuel production. Reference case prices for most fuels through 2020 are derived from the recent energy outlook published by Natural Resources Canada (the industrial and electricity coal price forecasts were derived from forecasts by the US Environmental Protection Agency). The price for petroleum products has been updated to reflect the recent increase in the price for crude oil, which at the time of writing had exceeded $140 per barrel. The price for petroleum products is based on historic data until May 2008 and the price for oil from the Energy Information Administration's most recent forecast.[8] The fuel price forecast (excluding electricity) for Ontario that was used to develop the reference case forecast in this report is presented in Table 4. The values differ slightly by province depending on the supply cost and taxation, but prices in Ontario are reasonably representative of the prices in the rest of the country. The forecasts for electricity prices are lower in provinces with greater hydroelectric potential – specifically British Columbia, Manitoba and Québec – and greater in provinces with fossil fuel generation (see Table 5). Like the other forecasts that are used as inputs to CIMS, it should be recognized that the fuel price forecast adopted here is highly uncertain, particularly in the longer term. In addition, the fuel price forecasts that we have adopted are intended to reflect long-term trends only, and will not reflect short-term trends caused by temporary supply and demand imbalances.

Table 4: Reference case price forecast for key energy commodities in Ontario

	Units	*2010*	*2020*	*2030*	*2040*	*2050*
Crude Oil (WTI)	*2005$ US / barrel*	85.57	56.97	66.67	69.04	69.04
Natural Gas						
Industrial	*2005$ / GJ*	9.63	8.71	8.71	8.71	8.71
Residential	*2005$ / GJ*	12.63	11.30	11.30	11.30	11.30
Commercial	*2005$ / GJ*	11.01	9.87	9.87	9.87	9.87
Electricity Generation	*2005$ / GJ*	9.00	8.89	8.89	8.89	8.89
Coal						
Market	*2005$ / GJ*	3.36	3.36	3.36	3.36	3.36
Electricity Generation	*2005$ / GJ*	3.00	3.00	3.00	3.00	3.00
Gasoline	*2005¢ / L*	108.8	81.7	88.7	88.7	88.7
Diesel (Road)	*2005¢ / L*	98.9	73.0	80.1	80.1	80.1

Note: All prices other than the price for oil are in Canadian dollars.

8 Energy Information Administration, 2008, "Annual Energy Outlook, 2008", United States Department of Energy.

Table 5: Reference case electricity price forecast in each province

	Units	*2010*	*2020*	*2030*	*2040*	*2050*
Industrial						
British Columbia	*2005¢ / kWh*	4.0	3.5	3.5	3.5	3.5
Alberta	*2005¢ / kWh*	6.2	5.6	5.6	5.6	5.6
Saskatchewan	*2005¢ / kWh*	6.0	5.5	5.5	5.5	5.5
Manitoba	*2005¢ / kWh*	3.7	2.7	2.7	2.7	2.7
Ontario	*2005¢ / kWh*	6.5	7.0	7.0	7.0	7.0
Québec	*2005¢ / kWh*	4.2	3.4	3.4	3.4	3.4
Atlantic	*2005¢ / kWh*	7.4	7.2	7.2	7.2	7.2
Residential						
British Columbia	*2005¢ / kWh*	7.4	6.5	6.5	6.5	6.5
Alberta	*2005¢ / kWh*	8.7	9.5	9.5	9.5	9.5
Saskatchewan	*2005¢ / kWh*	8.1	7.3	7.3	7.3	7.3
Manitoba	*2005¢ / kWh*	6.3	4.9	4.9	4.9	4.9
Ontario	*2005¢ / kWh*	8.9	9.9	9.9	9.9	9.9
Québec	*2005¢ / kWh*	8.3	8.4	8.4	8.4	8.4
Atlantic	*2005¢ / kWh*	11.4	10.8	10.8	10.8	10.8
Commercial						
British Columbia	*2005¢ / kWh*	4.5	4.0	4.0	4.0	4.0
Alberta	*2005¢ / kWh*	6.4	6.7	6.7	6.7	6.7
Saskatchewan	*2005¢ / kWh*	8.9	7.9	7.9	7.9	7.9
Manitoba	*2005¢ / kWh*	4.1	2.9	2.9	2.9	2.9
Ontario	*2005¢ / kWh*	7.7	9.1	9.1	9.1	9.1
Québec	*2005¢ / kWh*	4.6	3.7	3.7	3.7	3.7
Atlantic	*2005¢ / kWh*	9.1	8.8	8.8	8.8	8.8

Note: All prices are in Canadian dollars.

Policies included in the reference case

Both the federal and provincial governments have developed energy and climate policies over the past few years. We have attempted to include the most important of these in the reference case developed here. In particular, we include:

- The federal renewable power production incentive, which provides $0.01/kWh of renewable energy production during the first 10 years after commissioning of a new renewable energy facility;
- The federal ethanol excise tax exemption of $0.10/L and provincial tax exemptions for ethanol;
- The federal minimum energy performance standards for household appliances, including furnace regulations requiring 90% efficiency in new natural gas furnaces starting in 2009;
- The federal ecoENERGY for Efficiency policy, which provides incentives towards the replacement of lower efficiency energy consuming equipment with more efficient equipment.

Reference case energy and emissions outlook

Based on the key economic assumptions highlighted above, we used CIMS to develop an integrated reference case forecast for energy consumption and greenhouse gas emissions through 2050. The CIMS model captures virtually all energy consumption and production in the economy.

The reference case forecast for total energy consumption is shown in Table 6, while Table 7, Table 8, and Table 9 show natural gas, refined petroleum product, and electricity consumption, respectively. The residual energy consumption of other fuel types (total minus natural gas, refined petroleum product, and electricity) is not explicitly shown in this report.

Table 6: Reference case total energy consumption

	Unit	*2010*	*2020*	*2030*	*2040*	*2050*
Demand Sectors						
Residential	*PJ*	1,417	1,567	1,760	1,977	2,303
Commercial	*PJ*	1,195	1,412	1,639	1,956	2,298
Transportation	*PJ*	2,889	3,522	3,728	4,077	4,557
Manufacturing Industry	*PJ*	2,352	2,527	2,770	3,105	3,497
Supply Sectors						
Electricity Generation	*PJ*	3,881	4,127	4,626	5,448	6,560
Petroleum Refining	*PJ*	351	422	457	510	571
Crude Oil	*PJ*	1,034	1,996	2,202	2,342	2,506
Natural Gas	*PJ*	692	607	512	457	403
Coal Mining	*PJ*	22	24	25	26	27
Biofuels Manufacturing	*PJ*	2	4	13	16	20
Total	*PJ*	13,836	16,208	17,730	19,914	22,742

Note: Producer consumption of energy (e.g., consumption of hog fuel in the pulp and paper sector or refinery gas in the petroleum refining sector) is included in these totals. Energy consumption in the electricity generation sector includes consumption of water, wind, nuclear, and biomass using coefficients adopted from the International Energy Agency.[9]

[9] International Energy Agency, 2007, "Energy Balances of OECD Countries: 2004-2005". Renewable electricity generation is assumed to require 1 GJ of energy (e.g., wind, hydro) for each GJ of electricity generated. Nuclear electricity generation is assumed to require 1 GJ of energy for each GJ of thermal energy generated.

Table 7: Reference case natural gas consumption

	Unit	2010	2020	2030	2040	2050
Demand Sectors						
Residential	PJ	645	737	766	758	737
Commercial	PJ	613	745	880	1,055	1,235
Transportation	PJ	8	2	1	1	0
Manufacturing Industry	PJ	762	821	907	1,060	1,245
Supply Sectors						
Electricity Generation	PJ	265	304	346	421	488
Petroleum Refining	PJ	80	110	128	147	166
Crude Oil	PJ	542	955	1,058	1,072	1,162
Natural Gas	PJ	624	535	448	397	347
Coal Mining	PJ	3	3	4	4	4
Biofuels Manufacturing	PJ	1	1	5	7	7
Total	PJ	3,543	4,213	4,543	4,922	5,392

Table 8: Reference case refined petroleum product consumption

	Unit	2010	2020	2030	2040	2050
Demand Sectors						
Residential	PJ	66	18	11	9	7
Commercial	PJ	58	40	33	37	43
Transportation	PJ	2,873	3,503	3,660	3,931	4,348
Manufacturing Industry	PJ	147	161	160	183	203
Supply Sectors						
Electricity Generation	PJ	105	56	6	5	5
Petroleum Refining	PJ	92	92	90	98	109
Crude Oil	PJ	75	89	115	188	236
Natural Gas	PJ	25	24	20	18	16
Coal Mining	PJ	6	8	8	9	10
Biofuels Manufacturing	PJ	0	1	2	3	5
Total	PJ	3,448	3,993	4,106	4,482	4,982

Table 9: Reference case electricity consumption

	Unit	2010	2020	2030	2040	2050
Demand Sectors						
Residential	PJ	638	749	919	1,149	1,502
Commercial	PJ	524	627	726	864	1,020
Transportation	PJ	7	10	45	83	102
Manufacturing Industry	PJ	706	715	752	830	926
Supply Sectors						
Electricity Generation	PJ	0	0	0	0	0
Petroleum Refining	PJ	15	15	14	15	16
Crude Oil	PJ	60	92	92	88	86
Natural Gas	PJ	42	47	44	42	40
Coal Mining	PJ	4	5	4	5	5
Biofuels Manufacturing	PJ	0	0	2	2	3
Total	PJ	1,995	2,260	2,597	3,077	3,700

Based on total energy consumption as well as process emissions in the industrial and energy supply sectors, we calculate the greenhouse gas emissions associated with the reference case forecast (Table 10). While the CIMS model captures virtually all energy consumption and production in the economy, it does not capture the methane and nitrous oxide emissions from agriculture and the production of adipic and nitric acid, among other minor sectors. In 2005, these sectors represented about 10% of total greenhouse gas emissions, measured on an equivalent global warming potential basis.

Table 10: Reference case greenhouse gas emissions

	Unit	2010	2020	2030	2040	2050
Demand Sectors						
Residential	Mt CO_2e	39	40	41	40	39
Commercial	Mt CO_2e	35	41	47	56	66
Transportation	Mt CO_2e	208	253	263	282	312
Manufacturing Industry	Mt CO_2e	85	90	97	109	125
Landfills	Mt CO_2e	29	31	32	33	34
Supply Sectors						
Electricity Generation	Mt CO_2e	123	113	119	138	170
Petroleum Refining	Mt CO_2e	20	24	26	29	32
Crude Oil	Mt CO_2e	94	158	170	181	193
Natural Gas	Mt CO_2e	64	56	47	42	37
Coal Mining	Mt CO_2e	2	3	3	3	3
Biofuels Manufacturing	Mt CO_2e	0	0	1	1	1
Total	Mt CO_2e	698	807	845	915	1,012

In the absence of new policies to control greenhouse gas emissions, emissions are expected to grow from current levels in most sectors of the Canadian economy. Especially strong growth is expected in the crude oil and transportation sectors, as a result of rapidly expanding output.

Differences between the reference case and the reference case used in "Getting to 2050"

Since the modeling for *Getting to 2050*, CIMS has undergone several revisions of which we highlight the most major changes:

- **The price for refined petroleum products was updated to account for the recent rise in the price for oil and to incorporate the latest forecast from the Energy Information Administration.** In *Getting to 2050*, the price for oil was based on a forecast from Natural Resources Canada's *Canada's Energy Outlook*, which predicted that the world price oil would drop from $60 per barrel ($2003 US) in 2005 to $45 per barrel in 2010, and remain unchanged thereafter.[10] At the time of writing this report in 2008, the price for oil had exceeded $140 per barrel. In order to account for the higher price for oil, we revised the price for oil based

[10] The price for oil is based on the price of West Texas Intermediate at Cushing Oklahoma. Natural Resources Canada, 2006, "Canada's Energy Outlook".

the historic prices between January 2006 and May 2008 and the latest forecast from the Energy Information Administration (see Table 11).[11]

Table 11: Difference between the price for oil in *Getting to 2050* and the current report ($2005 US / barrel)

	2006-2010	*2011-2015*	*2016-2020*	*2021-2025*	*2026-2030*	*2031-2050*
Getting to 2050	$46.84	$46.84	$46.84	$46.84	$46.84	$46.84
Current Report (Historic & EIA, 2008)	$85.57	$64.24	$56.97	$61.22	$66.67	$69.04

- **Revised growth rates for the crude oil sector.** We reduced the growth rates for the crude oil sector to reflect the most recent forecast from the Canadian Association of Petroleum Producers. In *Getting to 2050*, the output from the crude oil sector reached 8,200 barrels per day in 2050, whereas in the present study, output reaches 7,000 barrels per day. We also increased the output of blended bitumen and reduced the output of synthetic crude, which reduces the emissions from the sector. By 2050, greenhouse gas emissions from the petroleum crude sector are approximately 110 Mt CO_2e lower in the current reference case than in *Getting to 2050*.
- **Revised growth rates for the transportation sector.** Since *Getting to 2050*, we increased the growth rates for passenger kilometers traveled by air and by road in the transportation sector. We revised the growth rates to reflect the growth rates reported in Natural Resources Canada's *Canada's Energy Outlook* (2006). The higher growth rates increase emissions from transportation, although the increase in emissions is moderated by the higher price for oil. In 2050, transportation emissions are approximately 40 Mt CO_2e greater than in *Getting to 2050*.
- **Revised growth rates for the industrial sectors.** In order to develop a forecast of industrial output to 2050, we extended the forecast from Natural Resources Canada, which ends at 2020. Since, *Getting to 2050*, we have moderated our growth rates for many industrial sectors, which reduced emissions by approximately 60 Mt CO_2e.
- **New landfill model.** We added a landfill model to account for the emissions and abatement opportunities from Canada's landfills. By 2050, we forecast landfills will produce approximately 34 Mt CO_2e in the absence of any mitigation policy.

In total, the changes made to CIMS between the *Getting to 2050* study and the current report reduced total greenhouse gas emissions in 2050 from 1,190 Mt to 1,015 Mt CO_2e.

The reference case in context

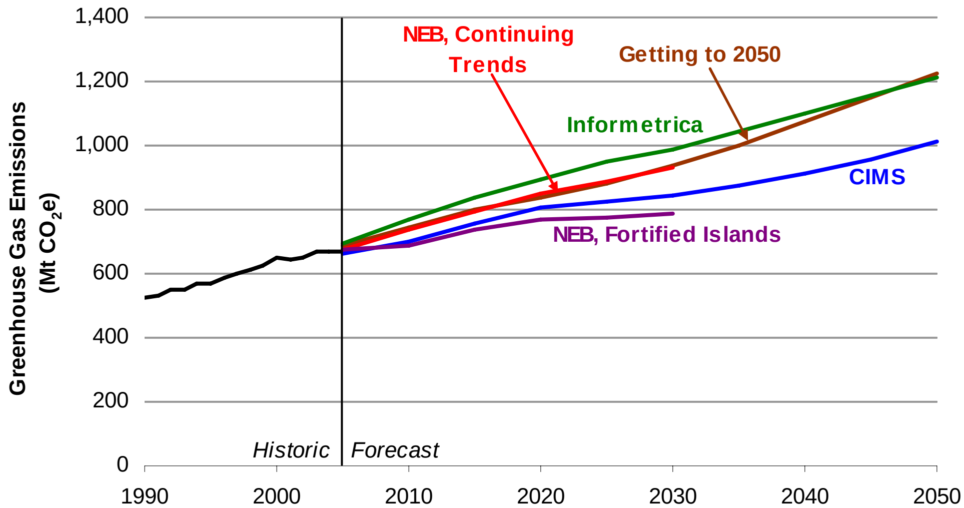
Figure 4 compares the total greenhouse gas emissions reported in this reference case to the reference case from *Getting to 2050*, a recent forecast by Informetrica Ltd. prepared for the federal government, and the recently released National Energy Board forecast. The National Energy Board published several forecasts with different assumptions about

[11] Energy Information Administration, 2008, "Annual Energy Outlook, 2008", United States Department of Energy.

energy prices: in the “Continuing Trends” forecast, the price for oil declines to $50 US per barrel by 2010, and in the “Fortified Islands” forecast, the price for oil remains at $85 per barrel through 2030. The price forecast for oil used in the present study is between the two forecasts from National Energy Board.

The forecast of greenhouse gas emissions in this report is generally lower than the forecasts from other sources, including the forecast from *Getting to 2050*. The lower forecast is mostly due to the increase in oil prices, but also due to changes in sector growth rates.

Figure 4: Reference case greenhouse gas emissions



Note: This chart excludes emissions from agroecosystems and some other sectors, which in 2005 represented about 10% of the Canada’s total. Historic emissions in this chart (1990-2005) are from Environment Canada, 2007, “National Inventory Report”.

A roadmap to deep reductions in greenhouse gas emissions

Context

This section explores how a deep reduction in greenhouse gas emissions affects the major sectors of the economy that contribute to greenhouse gas emissions and projects the environmental (measured in energy consumption and greenhouse gas emissions) and economic impacts (e.g., the cost of manufacturing cement or the cost of operating a household) of the reduction in greenhouse gas emissions. This section also forecasts the technological developments necessary to attain deep reductions in greenhouse gas emissions in each sector.

We use wedge diagrams to illustrate the relative contribution of different actions – taken by businesses and consumers – to a reduction in greenhouse gas emissions from their business as usual trajectory. In most cases, wedges are presented based on the *technical potential* for greenhouse gas reductions. While this can be a useful concept, it does not capture the relative cost of different actions, the behavior and preferences of firms and individuals, the interaction between different actions, or the types and stringency of policies that might be necessary to trigger the actions. Using CIMS, we instead present a wedge diagram for each sector based on the estimated response of firms and individuals to the regulatory framework as modeled. Because CIMS is an integrated model in which firm and consumer behavior has an empirical basis, the results account for preferences and behavior, the relative cost of different actions, and the interaction of actions, energy and goods and services prices and changes in output.

Each wedge corresponds to reductions of greenhouse gas emissions relative to the reference case as a result of key actions. The top wedge labeled "Energy Efficiency" represents the greenhouse gas reductions caused by increases in energy efficiency. Energy efficiency improves significantly in the reference case, and it should be noted that the wedge shown here only depicts the supplemental energy efficiency savings compared to the reference case. The wedge labeled "Carbon Capture & Storage" represents the greenhouse gas reductions from carbon capture and storage. The adoption of carbon capture and storage often increases the energy requirements of a sector, and offsets energy efficiency improvements in other end-uses. In order to show how the decline in energy efficiency from carbon capture offsets the other energy efficiency improvements, we show a wedge labeled "CCS Energy Penalty". The wedge labeled "Fuel Switching" captures the reductions associated with switching from fuels with relatively higher greenhouse gas intensity (e.g., coal) to fuels with lower intensity (e.g., electricity, renewable fuels or natural gas). The wedge labeled "Output" represents the reduction in greenhouse gas emissions caused by declines in production from the sector. We show additional wedges that represent other actions taken by firms to reduce their emissions, but that do not fall into the categories described above. These actions include flaring landfill gas, improved computer controls in aluminum smelting that reduce the occurrence of anode events that produce perfluorocarbons, and actions taken by the upstream oil and gas sectors to reduce fugitive emissions.

The analysis is carried out under several key assumptions, including:

- The current version of CIMS does not include a representation of agroecosystems, the production of nitric and adipic acid or some other minor sectors. As a result, the results shown here do not include the emissions or the abatement opportunities from these sectors. However, this analysis accounts for 90% of Canada's total greenhouse gas emissions.
- The technologies in CIMS are limited to foreseen technologies that are likely become commercially available in the timeframe of the analysis. However, high prices on greenhouse gas emissions could also stir the invention and commercialization of currently unforeseen low emissions technologies and processes. CIMS does not simulate the potential impact of these technologies, so it is likely that the modeling has missed some technological developments that could lower the long-term cost of carbon mitigation.
- Carbon capture is 90% effective at removing carbon dioxide from a flue gas stream. After including an energy efficiency penalty, a technology with carbon capture has approximately 15% of the emissions of an equivalent technology without. Future developments may improve capture efficiencies; these are not included in the modeling here.
- No nuclear energy is allowed in provinces that did not have nuclear electricity generation in 2005. Nuclear energy in other provinces has been constrained so that its share of total electric generation does not increase. We made these assumptions because the development of nuclear energy is a political decision as much as an economic one, and therefore difficult to simulate in an economic model.
- The greenhouse gas price policy simulated here is revenue neutral from a fiscal perspective, meaning that any revenue attained from the carbon price is returned to the sector that paid it. As a result, a sector as a whole does not incur any net costs associated with paying an emissions tax, but only incurs the investment costs associated with abating its emissions.
- The policy does not change the world price for crude oil or the continental price for natural gas, and do not change the overall output of these sectors (although, since domestic demand can change, the net exports of these commodities can change).

Residential

Box 1: Key actions by the residential sector

- Most emissions reductions are attained through the adoption of electric space and water heating systems. By 2050, virtually the entire space heating stock consists of ground source heat pumps or electric baseboards, and the entire water heating stock is electric.
- Improvements to residential building shells (i.e., improved insulation or energy efficient windows) have a minimal role in the emissions reductions.

In the absence of any mitigation policy, the greenhouse gas emissions from the residential sector are projected to remain fairly stable at about 40 Mt CO_2e between 2005 and 2050. In 2050, the residential sector is projected to contribute around 3% of Canada's total greenhouse gas emissions.

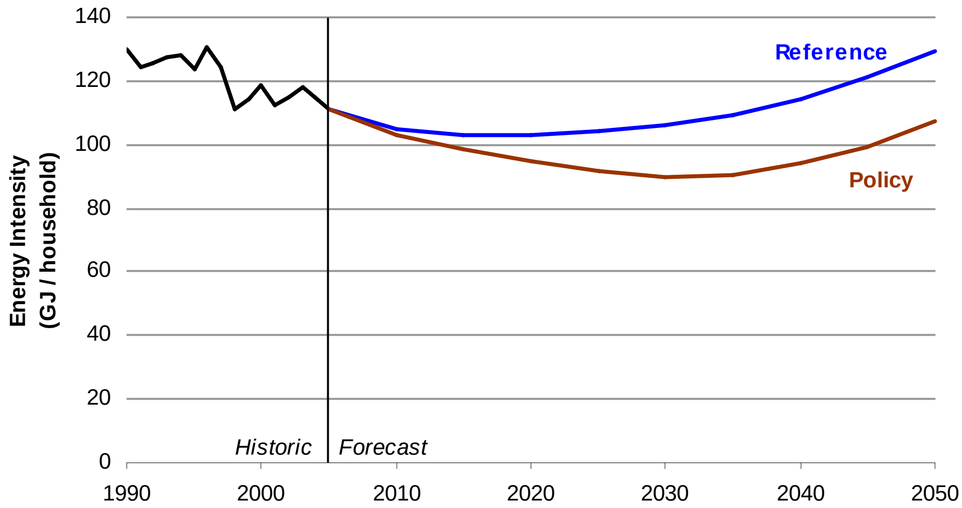
Two main energy end-uses produce almost all residential emissions: space heating accounts for approximately 58% of emissions, and water heating for around 42%. The emissions intensity of water heating is relatively similar across different provinces in Canada, but the emissions associated with space heating vary among provinces and depends largely on two factors. First, provinces with low prices for electricity – especially British Columbia, Manitoba and Québec – have lower greenhouse gas intensity for space heating because of a greater installation of electric baseboards. Second, the demand for space heating varies depending on climate. British Columbia and Ontario are generally warmer and require less space heating over the winter. These factors explain why Alberta, Ontario and Saskatchewan have the highest emissions intensity per unit of space heating.

Environmental impact of policy

The energy and greenhouse gas intensities of the sector in the reference and policy scenarios are shown in Figure 5 and Figure 6. In the reference scenario, energy intensity generally increases while greenhouse gas intensity declines. The increase in energy intensity is largely because of an increase in the energy consumption by miscellaneous appliances (e.g., televisions, cell phones). The forecast for the demand of miscellaneous appliances was estimated from historic data, which show a substantial increase between 1990 and 2005. The increase in energy consumption does not affect greenhouse gas intensity, however, because most miscellaneous appliances consume electricity. Greenhouse gas intensity declines in the reference scenario due mostly to energy efficiency improvements to residential shells and furnaces.

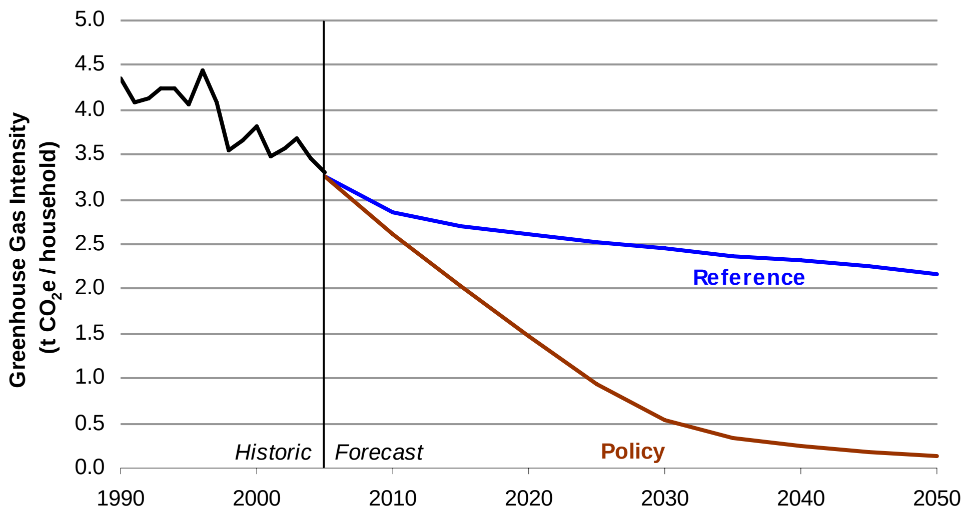
In the policy scenario, greenhouse gas intensity declines by 93% from the reference case projection. The installation of electric baseboards, ground source heat pumps and electric water heaters account for the majority of the decline.

Figure 5: Energy intensity of the residential sector



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 6: Greenhouse gas intensity of the residential sector



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

The residential sector switches primarily to electricity in response to the policy, most notably from natural gas (see Table 12). Electric baseboards, air and ground source heat pumps, which consume electricity, attain a significant market share by the end of the simulation. The shift away from renewable energy is caused by a decline in biomass space heating, which produces methane emissions.[12]

[12] Environment Canada, 2007, "National Inventory Report".

Table 12: Fuel switching in the residential sector

	2020	2030	2040	2050
Natural Gas	-18%	-32%	-34%	-30%
Electricity	20%	35%	36%	32%
Renewable	-2%	-2%	-1%	-1%

Economic impact of policy

Capital, operating and fuel costs increase with the policy's implementation (Table 13). Energy costs increase most significantly, because the policy encourages fuel switching from natural gas to electricity, which has a higher price per unit of energy produced. The rise in capital costs are more modest because the uptake of electric baseboards by some households – which are cheaper to install than natural gas furnaces – offset the cost of ground source heat pumps installed by other households. Overall, the total increase in cost per household is a fraction of one percent.

Table 13: Increase in the cost of the residential sector[13]

	Increase in Costs (2005$ / household)			
	2020	2030	2040	2050
Total Cost	$305.44	$447.05	$384.49	$366.42
Capital Costs	$73.41	$124.56	$114.38	$118.19
Operating & Maintenance Costs	$4.02	$5.44	$5.01	$5.57
Energy Costs	$228.00	$317.05	$265.10	$242.67

Provincial discussion

In response to the policy, households in all provinces make a shift towards low-emissions systems for space heating, but some provinces show a greater adoption of ground source heat pumps while others show greater penetration of electric baseboards. In Ontario, Alberta and Saskatchewan, 37%, 61% and 33% of households install ground source heat pumps by 2050, respectively. British Columbia, Manitoba, Québec and the Atlantic provinces show greater penetration of electric baseboards. By the end of the policy simulation, the difference in the greenhouse gas intensity of space heating is negligible among provinces (see Table 14).

Table 14: Space heating emissions intensity by province

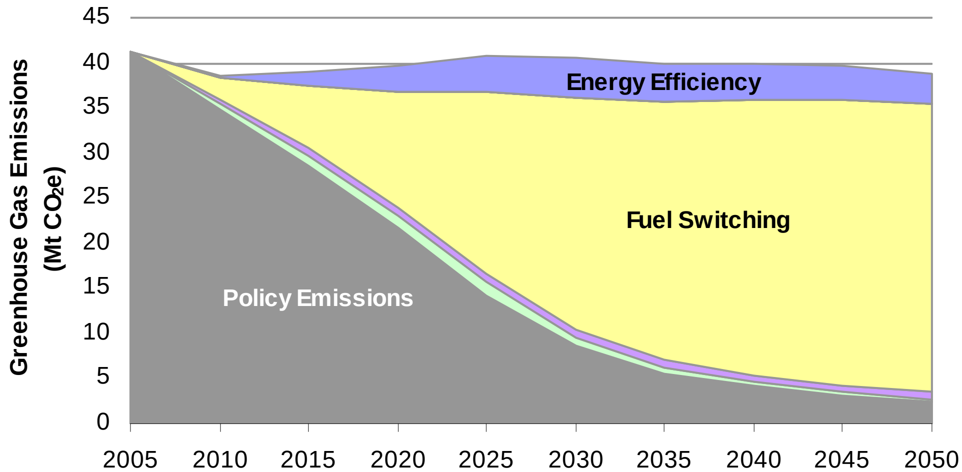
	Space Heating Emissions Intensity in Policy (t CO2e / m2 floorspace)				Increase due to Policy (%)			
	2020	2030	2040	2050	2020	2030	2040	2050
British Columbia	0.004	0.001	0.001	0.000	-34%	-74%	-85%	-89%
Alberta	0.019	0.007	0.002	0.001	-31%	-73%	-92%	-97%
Saskatchewan	0.011	0.003	0.001	0.000	-42%	-82%	-96%	-98%
Manitoba	0.003	0.000	0.000	0.000	-57%	-96%	-99%	-99%
Ontario	0.010	0.004	0.002	0.001	-32%	-70%	-88%	-93%
Québec	0.001	0.000	0.000	0.000	-84%	-96%	-92%	-92%
Atlantic	0.005	0.001	0.000	0.000	-54%	-85%	-96%	-99%

[13] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Technology roadmap to low emissions in the residential sector

Figure 7 illustrates the actions that contribute to the decline in greenhouse gas emissions in the residential sector. Fuel switching accounts for approximately 83% of the reduction, while energy efficiency (the adoption of ground source heat pumps contributes to energy efficiency in addition to fuel switching to electricity) contributes around 8%.

Figure 7: Wedge diagram for the residential sector



Residential shells show only a modest improvement in the policy scenario. The energy efficiency of building shells improves regardless of the policy – by 2050, residential shells are about 5% more efficient than standard construction in 2005. In the policy scenario, building shells improve slightly to around 8% more efficient than standard practices in 2005 (Table 15).

Table 15: Improvement in residential shells over standard practices in 2005

	2020	*2030*	*2040*	*2050*
Reference Case	0.2%	0.9%	2.4%	4.5%
Policy	0.5%	2.1%	4.8%	7.8%
Increase due to Policy	0.3%	1.2%	2.3%	3.3%

The main action to reduce greenhouse gas emissions in the residential sector is the adoption of electric space heating systems – by 2050 in the policy scenario, over 97% of installed heating systems use electricity (see Table 16). The installation of electric baseboards and ground source heat pumps account for the majority of installations, while air source heat pumps account for the remainder. Water heating also becomes mostly electric in response to the policy (Table 17).

Table 16: Penetration of electric space heating systems

	Technology Penetration (% of total stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Electric Baseboards	46%	51%	51%	51%	14%	19%	19%	19%
Air Source Heat Pumps	19%	31%	21%	13%	10%	19%	8%	1%
Ground Source Heat Pumps	0%	6%	22%	33%	0%	6%	21%	29%

Table 17: Penetration of electric water heating systems

	Technology Penetration (% of total stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Electric Water Heating	60%	83%	89%	93%	35%	62%	69%	72%

Provinces with higher forecasted electricity prices in the policy scenario – especially Alberta, Saskatchewan, Ontario and the Atlantic provinces – have greater incentives to reduce electricity costs by installing ground source heat pumps (see Table 18). Electric baseboards attain a greater penetration in provinces with lower electricity prices – British Columbia, Manitoba and Québec.

Table 18: Penetration of electric space heating systems by province in 2050

	Electric Baseboards	*ASHP*	*GSHP*
British Columbia	74%	13%	10%
Alberta	13%	10%	76%
Saskatchewan	44%	17%	38%
Manitoba	79%	12%	9%
Ontario	33%	19%	43%
Québec	94%	1%	3%
Atlantic	68%	5%	26%

The policy has a negligible impact on the capital expenditures of the sector (see Table 19). As discussed above, expenditures on ground source heat pumps tend to increase costs, but these are offset by reduced expenditures due to the installation of electric baseboards – which are generally cheaper to install than natural gas furnaces.

Table 19: Increase in capital expenditures in the residential sector

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	41	-117
Increase in Capital Expenditures (% above the reference case)	0%	0%

Commercial

Box 2: Key actions by the commercial sector

- The commercial sector reduces most of its greenhouse gas emissions through the adoption of electric heating systems – electric baseboards and ground source heat pumps. Ground source heat pumps have a greater adoption in provinces with higher electricity prices in the policy scenario.
- Building shells do not improve substantially in the policy scenario.

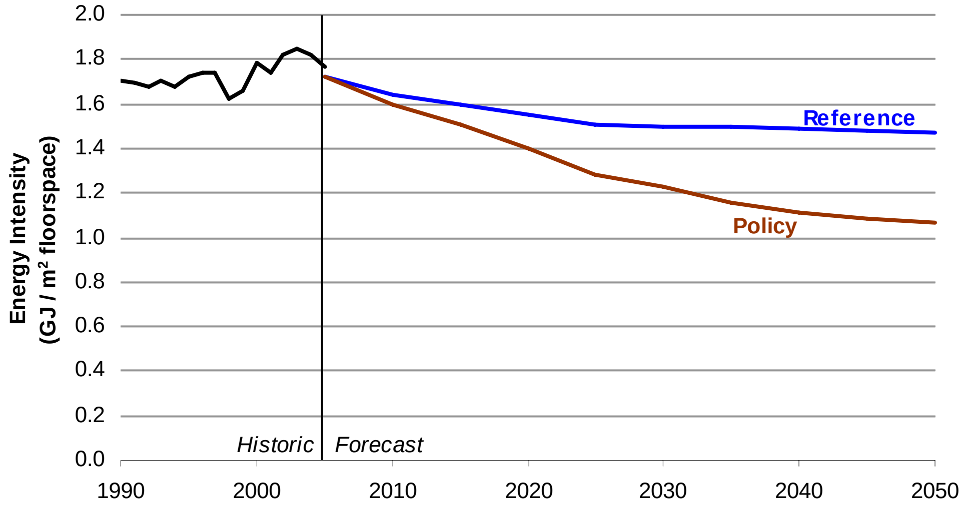
By the end of the simulation period, projected floor space in the commercial sector is expected to more than double, reaching 1,561 million m^2 in 2050. Greenhouse gas emissions mirror this growth and, in the absence of any emissions mitigation policy, increase from 34 Mt CO_2e in 2005 to 66 Mt CO_2e in 2050. Like the residential sector, space conditioning and water heating produce almost all commercial emissions: approximately 75% are attributed to space conditioning and 14% to water heating.

Many of the same factors responsible for provincial differences in the residential sector – differences in energy prices and climate – also influence the commercial sector. However, at the beginning of the simulation greenhouse gas intensity for space conditioning is reasonably similar among the provinces – around 0.05 t CO_2e per m^2 of floorspace for all provinces except British Columbia (which is lower) and Saskatchewan (which is higher).

Environmental impact of policy

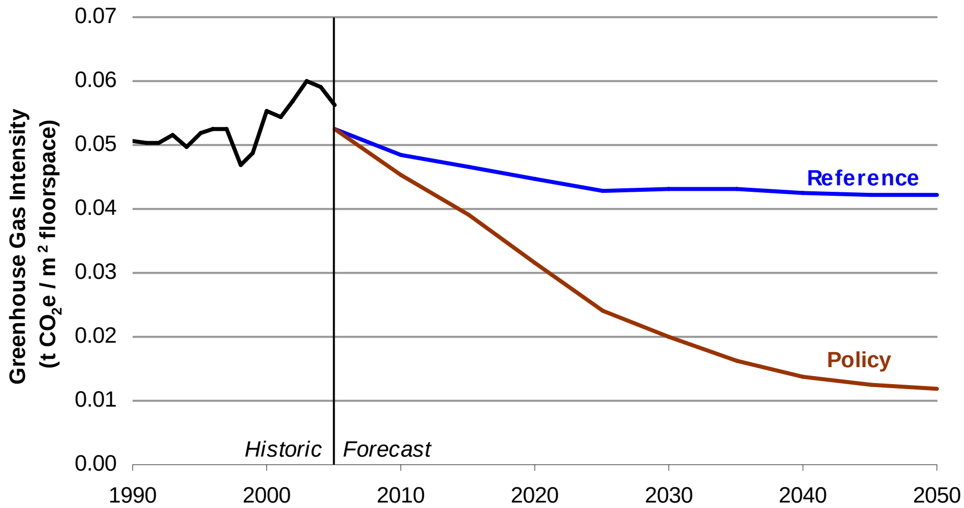
In the absence of any policy, the improvement in energy and greenhouse gas intensity over time is mostly the result of improvements in building shells and the installation of electric heating systems in some provinces. In the policy scenario, the adoption of electric space and water heating systems account for most of the reduction in energy and greenhouse gas intensity. By the end of the policy scenario, energy and greenhouse gas intensity decline by 38% and 70% from the reference case projection (see Figure 8 and Figure 9).

Figure 8: Energy intensity of the commercial sector



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 9: Greenhouse gas intensity of the commercial sector



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Similar to the residential sector, the commercial sector switches to electricity in response to the policy, most notably from natural gas (see Table 20). The policy induces a significant penetration of ground source heat pumps, but these actions show up as an increase in electricity consumption, rather than an increase in renewable consumption.

Table 20: Fuel switching in the commercial sector

	2020	*2030*	*2040*	*2050*
Natural Gas	-12%	-24%	-32%	-35%
Electricity	12%	24%	33%	35%

Economic impact of policy

Table 21 shows the increase in capital, operating and fuel costs caused by the policy. Capital costs show the only significant increase because the policy encourages the installation of improved building shells and ground source heat pumps, both of which have higher capital requirements than alternative options. Energy costs decline from the energy efficiency improvements to shells as well as the installation of ground source heat pumps. Overall, the total increase in cost per m^2 of floorspace is a fraction of a percent.

Table 21: Increase in the cost of the commercial sector[14]

	Increase in Costs (2005$ / m^2 floorspace)			
	2020	*2030*	*2040*	*2050*
Total Cost	-$0.20	$0.38	$0.21	$0.07
Capital Costs	-$0.54	$0.27	$0.90	$1.23
Operating & Maintenance Costs	$0.00	$0.00	$0.00	$0.00
Energy Costs	$0.34	$0.11	-$0.69	-$1.15

[14] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Provincial discussion

Similar to the residential sector, all provinces make a policy-induced shift towards more energy efficient building shells and electric space conditioning systems. In Ontario, Alberta and Saskatchewan, higher prices for electricity in the policy scenario encourage the adoption of ground source heat pumps, which meet most of the demand for space heating by 2050. British Columbia, Manitoba and Québec, which have lower electricity prices in the policy scenario, favor electric baseboards for space heating. Though technology choices differ, by 2050 at least 90% of installed heating systems in all provinces are either electric baseboard or ground source heat pumps, and the greenhouse gas intensity of space heating reaches approximately the same level in all provinces (see Table 22).

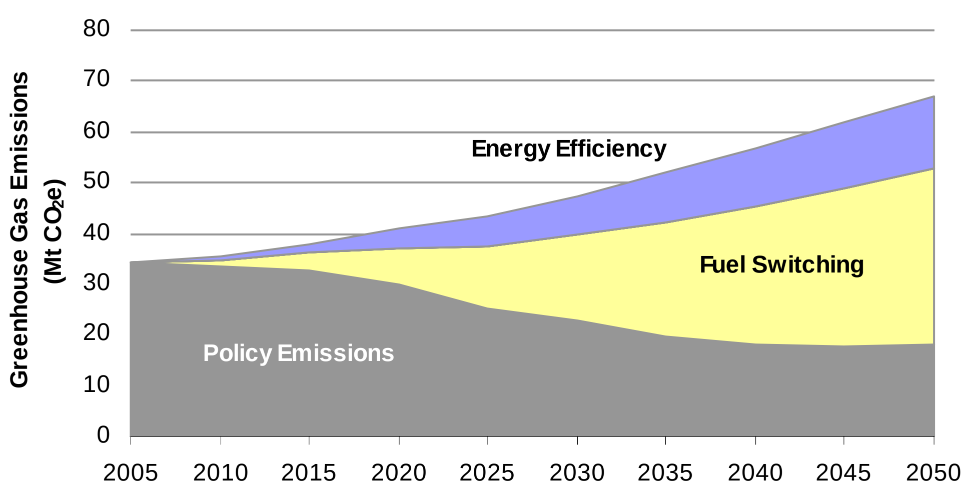
Table 22: Space conditioning emissions intensity by province

	Space Conditioning Emissions Intensity in Policy (t CO2e / m2 floorspace)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
British Columbia	0.017	0.011	0.008	0.008	-27%	-49%	-61%	-63%
Alberta	0.029	0.019	0.011	0.008	-32%	-57%	-74%	-80%
Saskatchewan	0.036	0.023	0.015	0.013	-27%	-49%	-65%	-70%
Manitoba	0.015	0.008	0.007	0.007	-28%	-46%	-47%	-47%
Ontario	0.029	0.019	0.010	0.007	-31%	-55%	-75%	-82%
Québec	0.015	0.008	0.007	0.007	-25%	-40%	-38%	-33%
Atlantic	0.027	0.017	0.010	0.007	-32%	-57%	-76%	-81%

Technology roadmap to low emissions in the commercial sector

Two key actions contribute to the decline in greenhouse gas emissions in the commercial sector. Fuel switching accounts for approximately 70% of the reduction in greenhouse gas emissions, while energy efficiency actions account for around 30% (Figure 10). Some actions, such as the adoption of ground source heat pumps, contribute to both improvements in energy efficiency and fuel switching to electricity.

Figure 10: Wedge diagram for the commercial sector



The policy does not induce significant improvements in building shells (see Table 23). By 2050 in the reference case, the average building shell is around 8% more efficient than standard construction in 2005; in the policy scenario, the average shell shows a small improvement of 1%.

Table 23: Improvement in commercial shells over standard practices in 2005

	2020	*2030*	*2040*	*2050*
Reference Case	1.9%	4.4%	6.4%	7.8%
Policy	2.6%	5.6%	7.7%	8.9%
Increase due to Policy	0.8%	1.2%	1.3%	1.1%

The main action that reduces the greenhouse gas emissions from the commercial sector is the adoption of electric heating systems. By 2050, heating systems have almost been completely decarbonized, with electric baseboards and ground source heat pumps accounting for 97% of installed systems.

Table 24: Penetration of commercial space-heating systems

	Technology Penetration (% of total stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Electric Furnaces	35%	42%	40%	36%	16%	24%	23%	20%
Ground Source Heat Pumps	16%	33%	52%	61%	10%	24%	41%	50%

Table 25 shows the penetration for electric furnaces and ground source heat pumps by province. British Columbia, Manitoba, Québec and the Atlantic provinces favor the installation of electric furnaces. Alberta, Saskatchewan and Ontario adopt a greater number of ground source heat pumps (GSHP) due, mostly, to higher electricity prices.

Table 25: Penetration of heating systems by province

	Electric Furnaces	*GSHP*
British Columbia	94%	4%
Alberta	32%	63%
Saskatchewan	11%	87%
Manitoba	53%	47%
Ontario	8%	89%
Québec	59%	41%
Atlantic	71%	23%

Capital expenditures by the commercial sector increase modestly in response to the policy (see Table 26). The decline in expenditures in the medium-term is mostly due to a greater penetration of electric baseboards, which have lower installation costs. In the long-term, capital expenditures increase due to the uptake of ground source heat pumps in many provinces.

Table 26: Increase in capital expenditures in the commercial sector

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-136	642
Increase in Capital Expenditures (% above the reference case)	-1%	2%

Transportation

Box 3: Key actions by the transportation sector

- The majority of emissions reductions are attained by fuel switching to electricity and renewable fuels (i.e., ethanol and biodiesel).
- By 2050 in the policy scenario, most passenger vehicles (85%) are plug-in hybrids.
- The policy causes significant increases in freight transport by rail, which has lower energy and greenhouse gas intensity per tonne of freight traveled. The policy also causes increases in passenger travel by transit.

Transportation is the largest contributor to Canada's greenhouse gas emissions by 2050, accounting for 310 Mt CO_2e and representing approximately 28% of total emissions.[15] Within the transportation sector, several end-uses contribute to greenhouse gas emissions, of which the most significant are passenger vehicles and road freight transportation. Passenger vehicles and road freight are each forecasted to produce approximately 40% of the transportation sector's emissions in 2050. Domestic aviation and domestic marine freight account for most of the remaining emissions.

The provincial differences in the transportation sector are relatively minor in comparison to other sectors, so we ignore them in this section. The key difference among provinces is that coastal provinces have marine freight transportation, whereas in-land provinces do not.

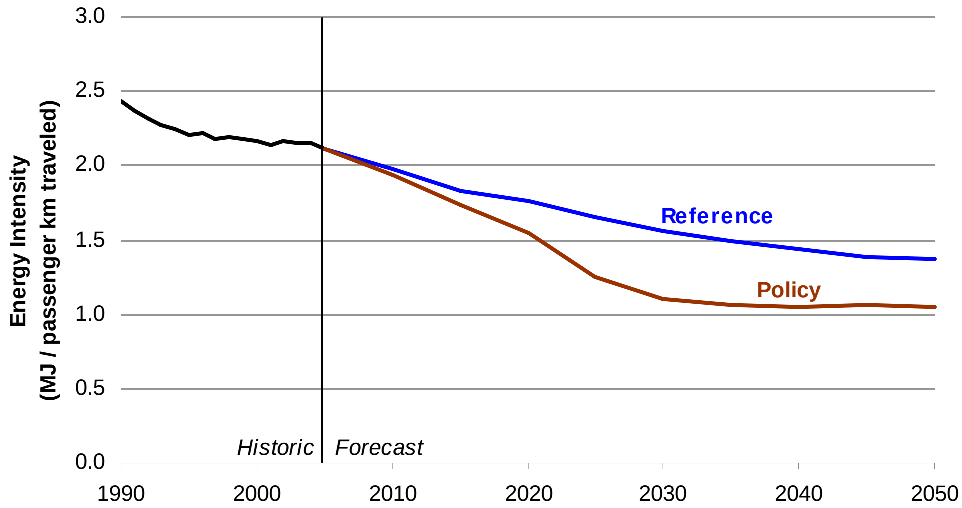
Environmental impact of policy

In the reference case, the decline in energy and emissions intensity is mostly the result of improvements to the energy efficiency of passenger vehicles (see Figure 11 and Figure 12). Energy efficiency of passenger vehicles increases due to improvements in engines (e.g., supercharged and turbo charged engines), as well as the adoption of hybrid cars, which account for 60% of the passenger vehicle stock in 2050.

After the policy's implementation, the energy and greenhouse gas intensity of passenger transportation decline by 23% and 68% from the reference case projection. The decline in emissions intensity is largely the result of a more rapid adoption of hybrid cars in the medium-term, and the adoption of plug-in hybrid vehicles and the consumption of biofuels (ethanol and biodiesel) in the long-term.

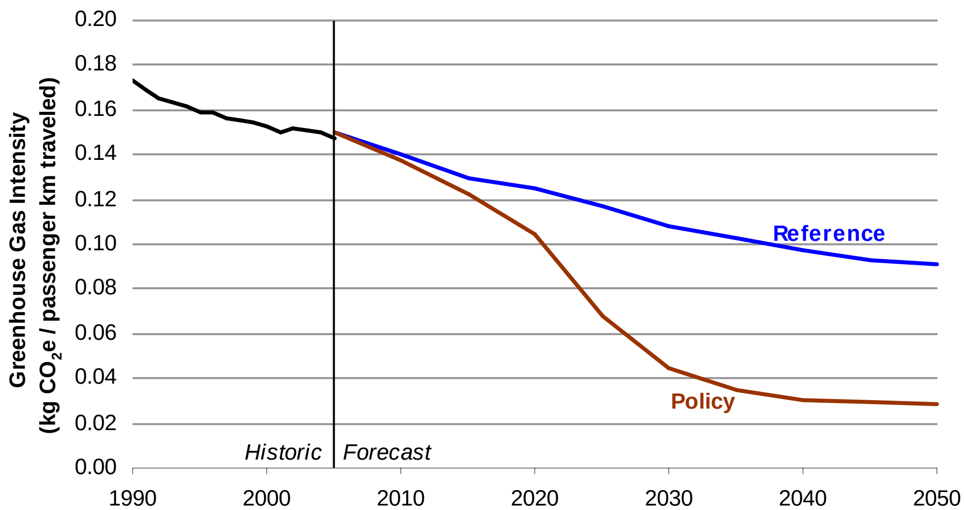
[15] The transportation sector excludes pipelines, which are accounted for in the fossil fuel extraction industries.

Figure 11: Energy intensity of personal transportation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

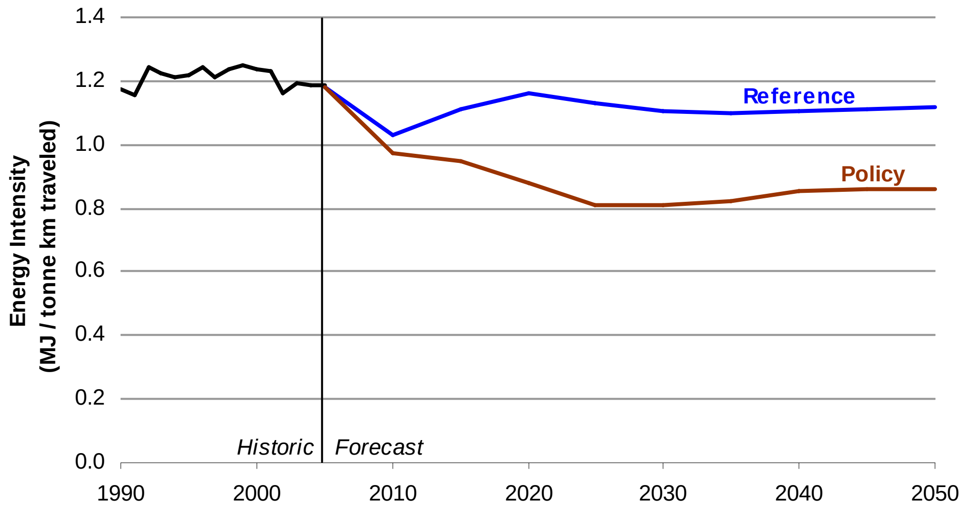
Figure 12: Greenhouse gas intensity of personal transportation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

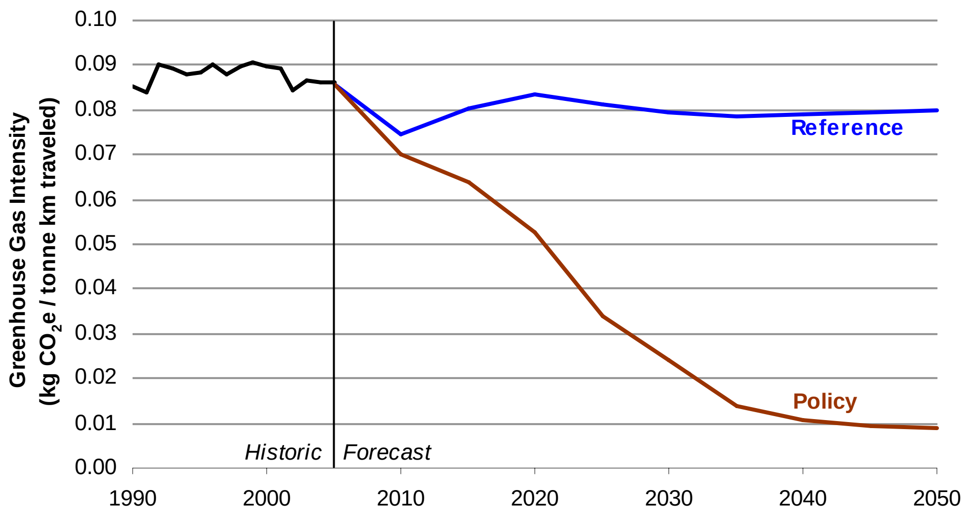
For freight transportation, energy and greenhouse gas intensity decline in the reference case, but less significantly than in the personal transportation sector (Figure 13 and Figure 14). In the policy scenario, the energy and greenhouse gas intensity of freight transportation decline from the reference case projection by 23% and 90%, respectively. The decline in emissions intensity is mostly the result of converting the road freight fleet to biodiesel, and a shift towards more transport by rail.

Figure 13: Energy intensity of freight transportation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 14: Greenhouse gas intensity of freight transportation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

The fuel share of refined petroleum products declines as a result of the policy, and the share of electricity and renewable fuels increases (Table 27). The increase in electricity consumption results mainly from the adoption of plug-in hybrid vehicles, which attain significant market shares by 2050.

Table 27: Fuel switching in transportation

	2020	*2030*	*2040*	*2050*
Refined Petroleum Products	-9%	-47%	-66%	-68%
Electricity	2%	9%	10%	10%
Renewable	7%	38%	55%	57%

Economic impact of policy

The costs of personal transportation decline by $12 per thousand person kilometer traveled, a 6% decrease (Table 28). The policy induces people to purchase smaller passenger vehicles and, to a lesser extent, to take public transit; therefore reducing the costs of personal transportation. The costs of freight transportation decline by approximately 6% in the policy scenario, mostly from a shift towards rail transport (Table 29). We note that the decline in the financial costs of passenger transportation does not reflect the full welfare cost caused by the policy, because it does not account for consumer preferences. Additionally, the decline in freight costs may be offset by rises in other costs (e.g., warehousing).

Table 28: Increase in the cost of passenger transportation[16]

	Increase in Costs (2005$ / '000 pkt)			
	2020	*2030*	*2040*	*2050*
Total Cost	-$16.51	-$24.05	-$13.56	-$12.00
Capital Costs	-$7.73	-$9.38	-$4.84	-$4.62
Operating & Maintenance Costs	-$4.36	-$5.42	-$3.61	-$3.51
Energy Costs	-$4.42	-$9.25	-$5.11	-$3.87

Table 29: Increase in the cost of freight transportation

	Increase in Costs (2005$ / '000 tkt)			
	2020	*2030*	*2040*	*2050*
Total Cost	-$15.25	-$12.14	-$4.45	-$4.46
Capital Costs	-$4.12	-$4.15	-$2.63	-$2.64
Operating & Maintenance Costs	-$5.86	-$5.60	-$4.71	-$5.10
Energy Costs	-$5.27	-$2.39	$2.89	$3.28

Technology roadmap to low emissions in transportation

The key actions that reduce emissions are fuel switching to renewables and electricity, and improvements in energy efficiency (see Figure 15). These actions account for 205 Mt CO_2e and 40 Mt CO_2e of emissions reductions in 2050, respectively.

[16] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Figure 15: Wedge diagram for personal and freight transportation

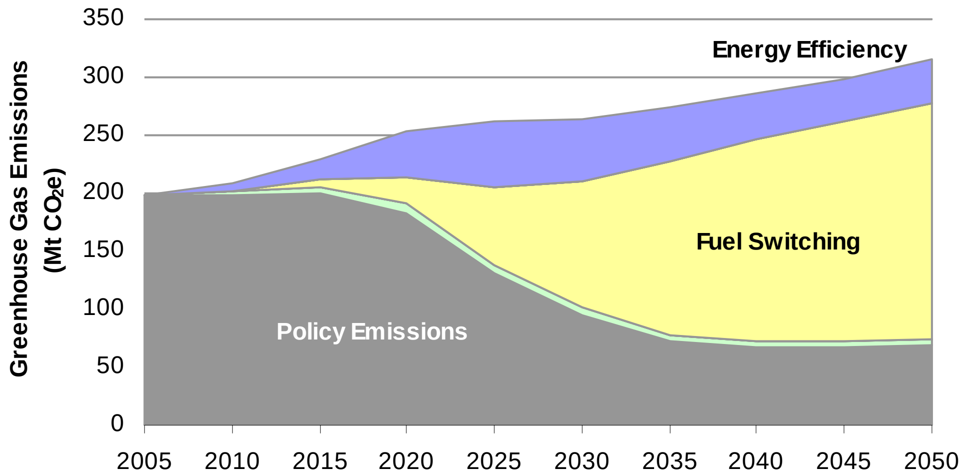


Table 30 shows the penetration of low- and zero-emissions passenger vehicles in the policy scenario and the increase relative to the reference case (i.e., a technology's penetration in policy minus its penetration in the reference case). The first response to the policy is that consumers begin purchasing hybrid vehicles. At the beginning of the policy simulation (up to 2030), the penetration of hybrid vehicles exceeds its penetration in the reference case, indicating that consumers select hybrid vehicles to reduce their emissions in the medium-term. By the end of the simulation, plug-in hybrids account for 83% of the passenger vehicle stock, while the penetration of hybrid vehicles is lower than its penetration in the reference case. Hybrid vehicles are likely transition technologies that enable manufacturers to accumulate experience with battery vehicles, and eventually apply that learning to develop plug-in hybrid vehicles.

Table 30: Penetration of low- and zero-emission passenger vehicles

	Technology Penetration (% of total Stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Hybrid	3%	6%	11%	12%	2%	3%	-14%	-29%
Plug-in Hybrid	6%	18%	21%	21%	6%	10%	7%	6%
Plug-in Hybrid Ethanol	7%	51%	62%	62%	7%	50%	60%	59%

By 2050, the policy induces a 3% increase in the occupancy of passenger vehicles and a 14% increase in transit ridership (Table 31). The increase in transit ridership and vehicle occupancy peaks in 2030 and declines thereafter due to two factors. First, the emissions costs of driving a passenger vehicle are greater in 2030 because the stock of vehicles is more greenhouse gas intensive. By 2050, the vehicle stock produces fewer greenhouse gases per kilometre traveled and driving increases. Second, the cost of purchasing low- and zero-emissions vehicles declines over the policy simulation as manufacturers accumulate experience with these vehicles. By 2050, the purchase cost of a low or zero-emission vehicle is lower than it was in 2030.

Table 31: Mode switching in personal transportation

	Mode Penetration				Increase due to Policy (%)			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Vehicle Occupancy (people per car)	2.3	2.3	2.3	2.2	5%	6%	4%	3%
Transit Ridership (billion pkm)	29.5	36.0	37.4	40.8	26%	27%	16%	14%

In freight transportation, the key actions that reduce greenhouse gas emissions are fuel switching to biodiesel in the road freight sector, and an increase in rail travel. By 2050 in the policy scenario, almost all freight trucks consume biodiesel instead of refined petroleum products (see Table 32). Rail transport increases in response to the policy – by 2050, rail freight accounts for about 70% of all freight transport (see Table 33).

Table 32: Fuel share for biodiesel among freight trucks

	Technology Penetration (% of total Stock)				Increase due to Policy (%)			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Biodiesel fuel share	20%	72%	96%	97%	20%	72%	96%	97%

Table 33: Freight transport by mode

	Technology Penetration (tonnes km traveled)				Increase due to Policy (%)			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Rail Freight	576	701	801	930	23%	19%	18%	20%
Truck Freight	194	211	312	379	-46%	-47%	-38%	-40%

Table 34 shows the increase in capital expenditures required to attain the reductions in the transportation sector. Capital expenditures decline in response to the policy for three reasons. First, the policy encourages consumers to adopt smaller vehicles and, to a lesser extent, to take public transit, which have lower capital requirements per unit of passenger travel. Second, the freight industry ships a greater portion of freight using rail, which also reduces capital expenditures. Third, the amount of freight travel declines, therefore reducing capital expenditures.

Table 34: Increase in capital expenditures in transportation

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-8,414	-6,892
Increase in Capital Expenditures (% above the reference case)	-12%	-7%

Uncertainty in the analysis

The emissions reductions from the transportation sector are largely dependent on the availability of biofuels. The uncertainty associated with availability of renewable fuels is discussed in the section on biofuels. If biofuels are not available in the quantities required to attain deep reductions in the transportation sector, other fuels, such as hydrogen, may play a more prominent role in the sector.

Chemical products manufacturing

Box 4: Key actions by the chemical products sector

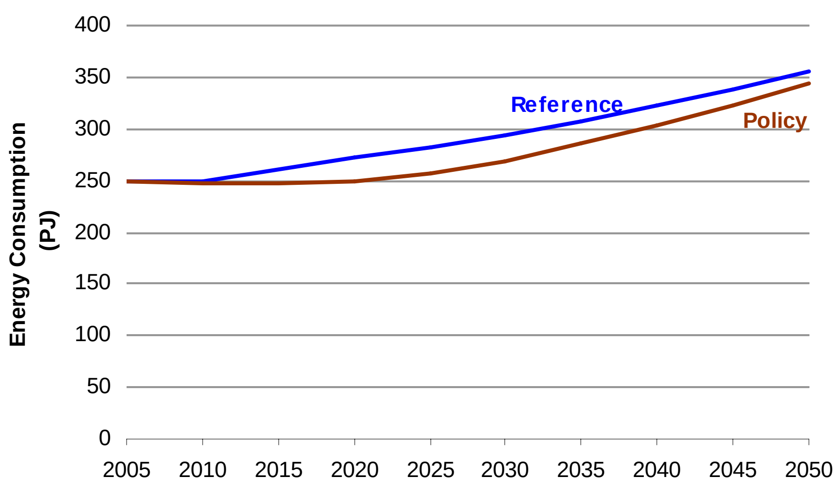
- Ammonia manufacturing produces a relatively pure stream of carbon dioxide, offering substantial opportunity for the rapid penetration of carbon capture and storage. As early as 2020 in the policy scenario, 67% of ammonia production employs carbon capture.

Greenhouse gas emissions from the chemicals manufacturing sector were 11 Mt CO_2e in 2005 and are forecasted to rise to 16 Mt CO_2e by 2050. Alberta and Ontario account for 75% and 20% of greenhouse emissions from the sector, respectively. The remaining 5% of emissions originate from British Columbia and Québec. The production of process heat required in petrochemical manufacturing and process emissions from ammonia manufacturing are expected to be the largest sources of emissions.

Environmental impact of policy

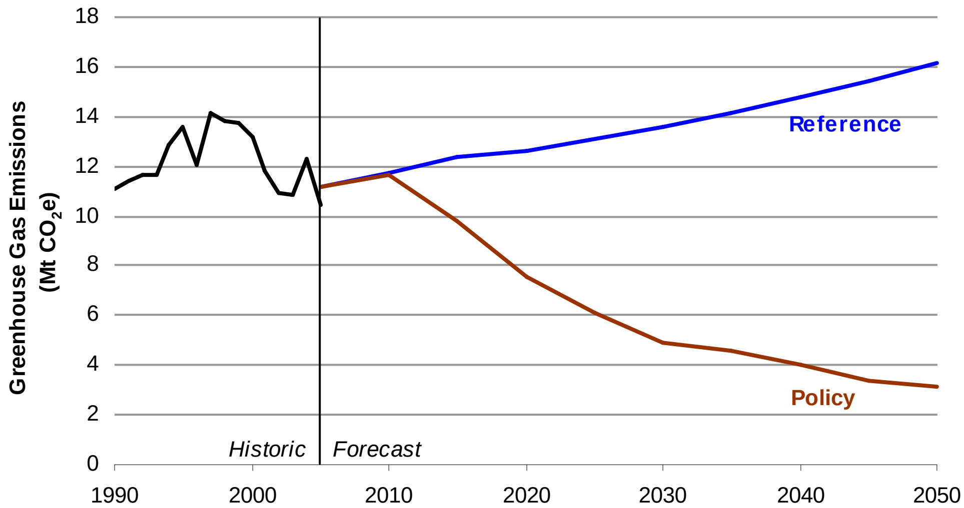
The chemicals manufacturing sector consumed 249 PJ in 2005, and in the reference scenario, consumption rises to 355 PJ in 2050, an increase of 42% (see Figure 16). Energy consumption is only slightly lower in the policy scenario, reaching 349 PJ in 2050. Energy efficiency improvements are outweighed by carbon capture and storage, which requires additional energy consumption.

Figure 16: Energy consumption from chemicals manufacturing



Greenhouse gas emissions also increase steadily in the reference scenario, from 11 Mt CO_2e in 2005 to 16 Mt CO_2e in 2050 (Figure 17). However, in the policy scenario the emissions drop sharply after 2015, reaching 3.4 Mt CO_2e in 2050. The dominant action responsible for decreasing emissions is carbon capture and storage associated with the production of ammonia and process heat.

Figure 17: Greenhouse gas emissions from chemicals manufacturing



Source: Historic data for combustion greenhouse gas emissions are from NRCan, 2008, "Comprehensive Energy Use Database"; historic data for process emissions are from Environment Canada, 2007, "National Inventory Report"

In response to the policy, natural gas consumption declines in favor of electricity (see Table 35). Coal consumption shows a modest increase due to its potential to be combusted in boilers using carbon capture and storage.

Table 35: Fuel switching in chemicals manufacturing

	2020	*2030*	*2040*	*2050*
Natural Gas	-9%	-14%	-15%	-15%
Coal	3%	3%	2%	1%
Refined Petroleum Products	0%	0%	0%	0%
Electricity	6%	11%	13%	14%
Renewable	0%	0%	0%	0%

Economic impact of policy

Table 36 shows the increase in the cost of chemicals manufacturing that results from the policy. Energy costs increase most significantly due to a greater consumption of electricity, which is more costly per unit of energy. Overall, total costs are $22.18 per tonne higher in 2050 than in the reference scenario, an increase of 2.6%.

Table 36: Increase in the cost of chemicals manufacturing[17]

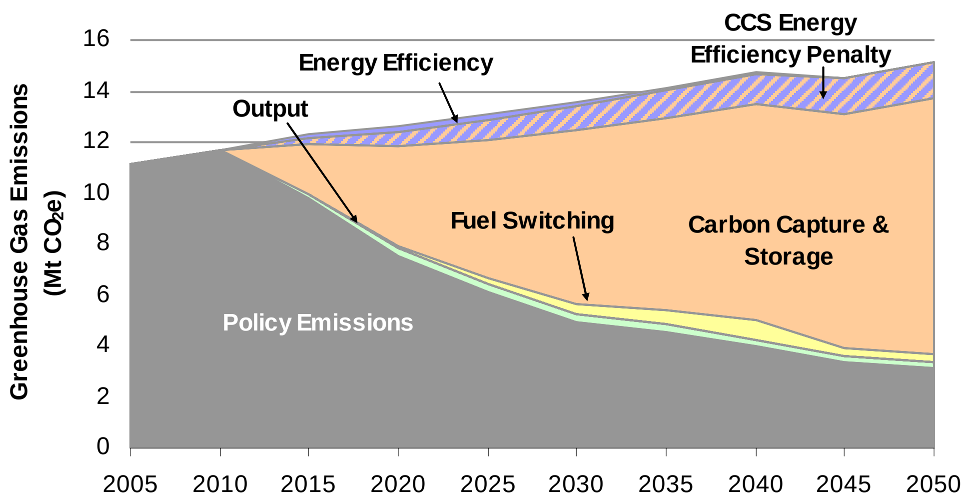
	Increase in Costs (2005$ / tonne product)			
	2020	*2030*	*2040*	*2050*
Total Cost	$7.70	$16.05	$19.26	$22.18
Capital Costs	$1.48	$2.63	$2.98	$3.20
Operating & Maintenance Costs	$3.39	$4.28	$4.56	$4.68
Energy Costs	$2.83	$9.14	$11.73	$14.29

[17] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Technology roadmap to low emissions in chemicals manufacturing

In 2050, the policy induces a 13 Mt CO_2e reduction in the greenhouse gas emissions from the chemicals manufacturing sector. Carbon capture and storage is responsible for the majority of emissions reductions, while fuel switching and a modest decline in output contribute to the remaining reductions (see Figure 18).

Figure 18: Wedge diagram for chemicals manufacturing



The adoption of carbon capture and storage in ammonia production may be an early opportunity for experimenting with the technology. Hydrogen production for ammonia manufacturing can be designed or retrofitted to produce a relatively pure stream of carbon dioxide, therefore avoiding the process of separating the carbon dioxide from other flue gases, which is considered the most costly process involved in carbon capture and storage. The Intergovernmental Panel on Climate Change estimates the cost of carbon capture associated with ammonia production to be between $5 and $55 (USD) / tonne CO_2e.[18] In addition, the majority of ammonia production occurs in Alberta (90%), which has significant potential for the geologic storage of carbon dioxide.[19]

Table 37 shows the penetration of carbon capture and storage in ammonia production and process heat generation. By 2050 in the policy scenario, 67% of ammonia production occurs in facilities using carbon capture and storage, rising to virtually 100% by 2040. The penetration of carbon capture and storage is less rapid in process heat generation, reaching 66% in 2050.

Table 37: Penetration of carbon capture and storage in chemicals manufacturing

	2020	*2030*	*2040*	*2050*
Ammonia Production	67%	93%	98%	99%
Process Heat Generation	12%	38%	52%	66%

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[18] Intergovernmental Panel on Climate Change, 2005, "Carbon Dioxide Capture and Storage".

[19] ecoENERGY Carbon Capture and Storage Task Force, 2008, "Canada's Fossil Energy Future," http://www.energy.gov.ab.ca/Org/pdfs/Fossil_energy_e.pdf

Capital expenditures decrease in the policy scenario due to a modest decline in output (output declines by 3% relative to the reference scenario in 2050). The decline in output offsets the increase in capital expenditures due to the adoption of carbon capture and storage (see Table 38).

Table 38: Increase in capital expenditures in chemical manufacturing

	Medium-Term (2011-2025)	*Long-term (2026-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-7	-1
Increase in Capital Expenditures (% above the reference case)	-1%	0%

Uncertainty in the analysis

This analysis does not consider the potential to reduce emissions from adipic or nitric acid production, which contributed to 1.4 Mt CO_2e in 2005. A variety of abatement technologies are currently available that can reduce the majority of these emissions.[20]

Cement and lime manufacturing

Box 5: Key actions by the cement and lime manufacturing sector

- Most emissions reductions are attained through the adoption of carbon capture and storage.

In the absence of any mitigation policy, greenhouse gas emissions from cement and lime manufacturing are expected to rise from 15 Mt CO_2e in 2005 to 30 Mt CO_2e in 2050; by the end of the simulation period, the cement and lime sectors account for approximately 3% of Canada's total greenhouse gas emissions. Almost all greenhouse gases are emitted during the operation of the cement and lime kilns, which require process heat to decompose calcium carbonate ($CaCO_3$) into lime (CaO). The calcination process also produces carbon dioxide in amounts that typically exceed the emissions generated through combustion alone. In the reference case scenario, coal combustion meets most of the demand for process heat.

Cement and lime manufacturing is relatively similar in all provinces, so we omit any provincial discussion.

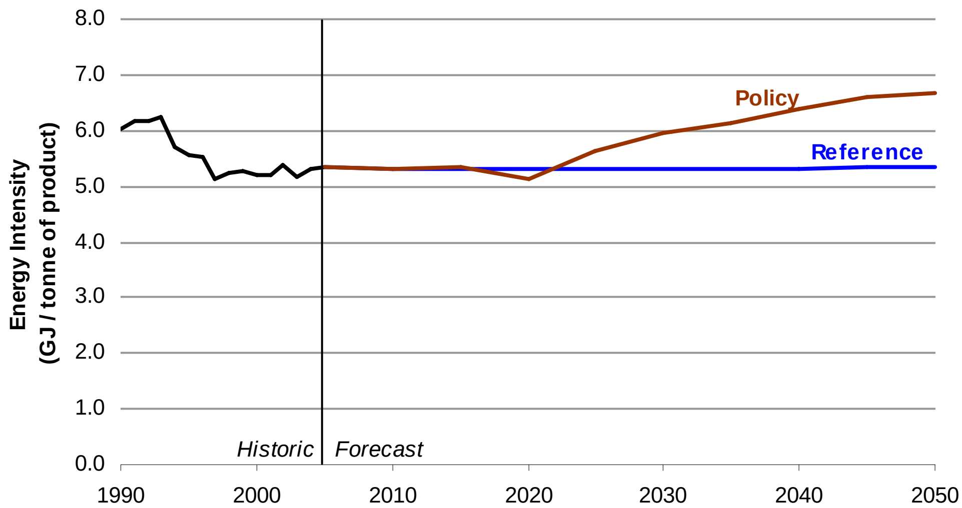
Environmental impact of policy

In the reference case, both the energy and greenhouse gas intensity remain stable because we project few opportunities for improvement in energy efficiency (see Figure 19 and Figure 20). In the policy scenario, energy intensity initially drops, but then increases as these sectors begin to adopt carbon capture and storage. The early decline is due mostly to a greater decline in the output of the lime sector relative to the cement sector, which is less energy intensive. Therefore, this decline does not represent a substantial improvement in the energy efficiency of the cement or lime sectors. By the end of the

[20] Environment Canada, 2008, "National Inventory Report"; Mainhardt & Kruger, 2008, "N_2O Emissions from Adipic Acid and Nitric Acid Production," http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

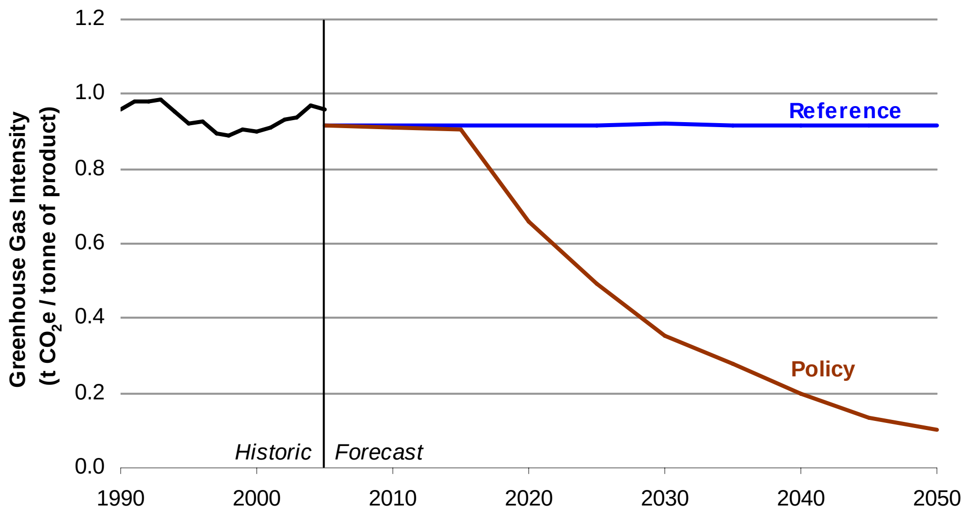
simulation period, the energy intensity of these sectors increases as they adopt carbon capture and storage. The greenhouse gas intensity of cement and lime manufacturing declines by 89% in the policy scenario.

Figure 19: Energy intensity of cement and lime manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 20: Greenhouse gas intensity of cement and lime manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

By 2050, the sector increases its use of natural gas to provide the process heat for kiln operations, and it reduces its consumption of coal and petroleum products (mostly petroleum coke). The increase in electricity consumption is due to the electricity requirements for operating the carbon capture equipment (see Table 39).

Table 39: Fuel switching in cement and lime manufacturing

	2020	*2030*	*2040*	*2050*
Natural Gas	14%	32%	28%	24%
Coal	8%	-7%	-3%	1%
Petroleum Products	-23%	-28%	-29%	-29%
Electricity	3%	5%	6%	6%
Other	-1%	-2%	-2%	-2%

Economic impact of policy

The cost of producing cement and lime rises by approximately $34 per tonne by 2050 in response to the policy, an 11% increase from the reference case projection (Table 40). Capital and energy expenditures account for the greatest portion of the increase in costs because carbon capture increases the capital and energy requirements of producing a unit of cement or lime. Fuel switching to natural gas from coal adds to the increase in energy costs, because it is relatively more costly per unit of energy.

Table 40: Increase in the cost of cement and lime manufacturing[21]

	Increase in Costs (2005$ / tonne of cement or lime)			
	2020	*2030*	*2040*	*2050*
Total Cost	$11.24	$28.11	$32.32	$33.62
Capital Costs	$6.05	$11.24	$13.19	$13.40
Operating & Maintenance Costs	-$0.55	-$0.66	-$0.74	-$0.80
Energy Costs	$5.75	$17.53	$19.87	$21.01

Technology roadmap to low emissions in cement and lime manufacturing

Figure 21 shows the actions that contribute to the decline in greenhouse gas emissions for the cement and lime sector. In 2050, carbon capture and storage accounts for 70% of the emissions reductions, while fuel switching to natural gas and the decline in output each account for 15%.

[21] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Figure 21: Wedge diagram for cement and lime manufacturing

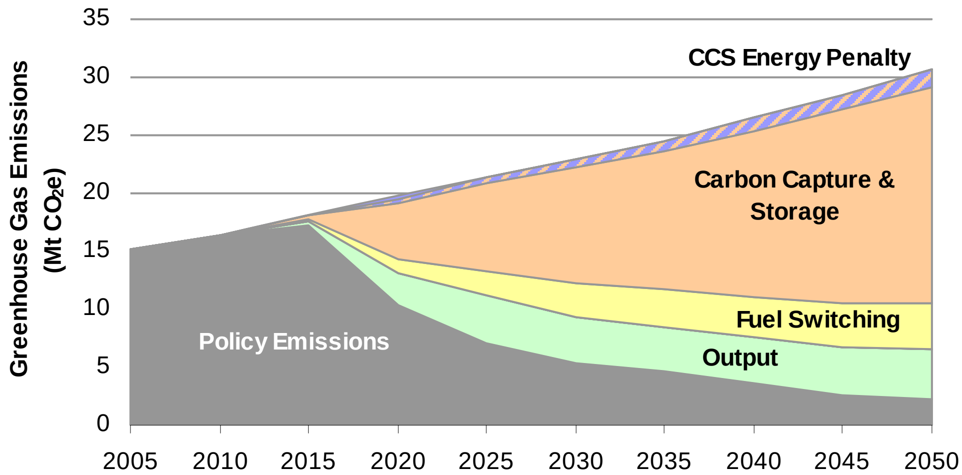


Table 41 illustrates the penetration of carbon capture in the cement and lime manufacturing sectors. The penetration in the cement industry is more rapid than in the lime industry because lime kilns are often smaller point-sources of greenhouse gas emissions. Therefore, the cost of pipeline construction is likely to be more expensive for the lime industry – the capital cost of building the pipeline is roughly the same, but it transports less carbon dioxide. By 2050, most lime and cement facilities in Canada employ carbon capture.

Table 41: Penetration of carbon capture and storage in cement and lime manufacturing

	2020	*2030*	*2040*	*2050*
Lime	11%	35%	68%	99%
Cement	48%	59%	85%	99%

Capital expenditures by the sector generally decline in response to the policy due to the decline in output (Table 42). The decline in output offsets the increase in capital expenditures from adopting carbon capture equipment.

Table 42: Increase in capital expenditures in cement and lime manufacturing

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-227	-425
Increase in Capital Expenditures (% above the reference case)	-38%	-52%

Uncertainty in the analysis

Adding cementitious material (e.g., iron and steel blast furnace slag, pozzolanic earths or fly ash) to the ground clinker would reduce emissions intensity of the final product (ground clinker or the final end product, cement), and may be the initial response to any reduction technique in the cement industry. Adding cementitious material is not included in our analysis because the amount of cementitious material that can be added to cement is both regulated by government and limited by physical constraints. However, adding cementious material may enable the sector to attain appreciable emissions reductions at little additional cost.

This analysis shows a significant decline in output from the sector as a result of the policy's implementation. In our analysis, we have assumed that Canada remains an open economy and that many developing countries do not take the same efforts to reduce greenhouse gas emissions. As a result, the cement industry may have an incentive to move production overseas to a country with lower constraints on greenhouse gas emissions. We have not examined how policies can prevent the displacement of these industries.[22]

Iron and steel manufacturing

Box 6: Key actions by the iron and steel sector

- Most emissions reductions are attained through the adoption of carbon capture and storage.

Greenhouse gas emissions from the iron and steel manufacturing sector increase modestly in the reference case, from 15 Mt CO_2e in 2005 to 17 Mt CO_2e in 2050. In 2050, the iron and steel sector is projected to contribute 2% of Canada's total greenhouse gas emissions.

Steel can be produced in integrated steel mills or in mini-mills using electric arc furnaces. Integrated steel mills produce virgin steel from raw materials and are projected to contribute to approximately 51% of the sector's steel and 85% of the sector's greenhouse gas emissions by 2050. Currently, these mills produce steel using three energy and emissions-intensive processes. First, the production of metallurgical coke, used to reduce iron ore to pig iron, requires process heat to bake coal in an airless chamber. In the blast furnace, which is responsible for approximately 70% of an integrated steel mill's greenhouse gas emissions, the coke is ignited at high temperature to produce carbon monoxide. The carbon monoxide strips oxygen from the iron ore to generate pig iron and carbon dioxide. Most of the remaining carbon monoxide within the flue gas is captured and used as fuel elsewhere in the plant. Steel is produced in the final phase, where high purity oxygen is passed over the molten iron to remove any excess carbon. The oxygen reacts with the carbon to produce carbon dioxide or carbon monoxide, which is again captured and used for fuel elsewhere in the plant.[23]

Electric arc furnaces in mini-mills, which produce recycled steel, are expected to account for 49% of the sector's steel and 5% of its greenhouse gas emissions. By 2050, electric arc steel-making is much less energy and emissions intensive because it avoids the coking, blast furnace and basic oxygen furnace processes. It also uses electricity as the main source of energy, which does not produce direct greenhouse gas emissions. Some process emissions are generated as the carbon anodes oxidize, which are used to deliver

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[22] For information on policies to prevent the displacement of industries overseas, see Fischer C., Fox A., 2007, "Comparing policies to combat emissions leakage: Border tax adjustments versus rebates".

[23] Environmental Protection Agency, 1995, "AP-42", http://www.epa.gov/ttn/chief/ap42/; Intergovernmental Panel on Climate Change, 2005, "Carbon Dioxide Capture and Storage".

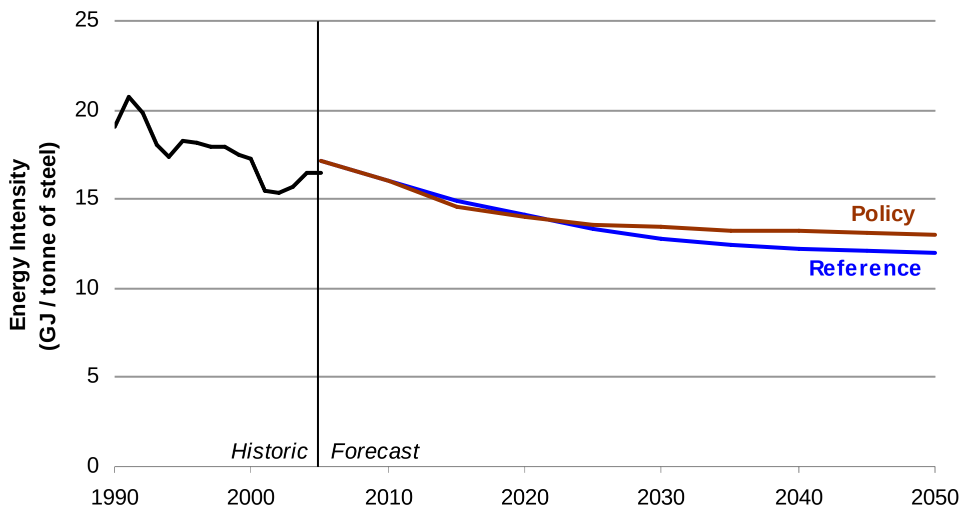
electricity to the mass of steel. Fossil fuels may also be injected into the furnaces to purify the metals.

Environmental impact of policy

Energy and greenhouse gas intensity decline in the reference case, largely due to an increase in production from electric arc furnaces, which rises from 36% of Canada's total steel output in 2005 to 49% in 2050 (Figure 22 and Figure 23). However, the energy and emissions intensity of both integrated mills and mini-mills decline in the reference case.

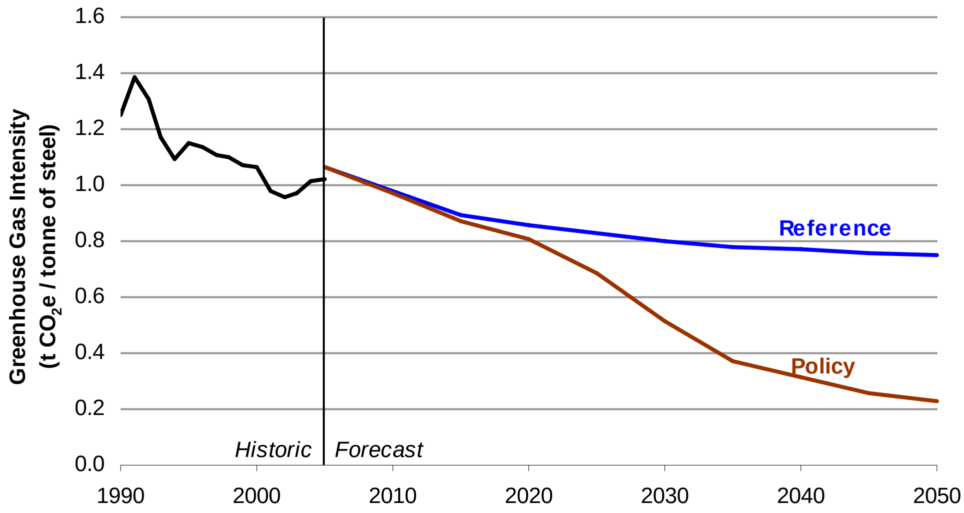
In the policy scenario, steel manufacturing becomes more energy intensive as a result of the energy penalty associated with carbon capture and storage. The increase in energy intensity caused by carbon capture and storage offsets any other improvements in energy efficiency, such as the adoption of the COREX® process in integrated steel making (which reduces the input of coal). Greenhouse gas intensity is projected to be 70% lower in the policy scenario projection (0.24 tonne CO_2e per tonne of steel) than in the reference case.

Figure 22: Energy intensity of iron and steel manufacturing



Source: Historic data are from CIEEDAC, 2008, "Database on Energy, Production and Intensity Indicators for Canadian Industry"

Figure 23: Greenhouse gas intensity of iron and steel manufacturing



Source: Historic data are from CIEEDAC, 2008, "Database on Energy, Production and Intensity Indicators for Canadian Industry"

Table 43 shows changes in fuel shares that result from the policy's implementation. The sector shows minor fuel switching to electricity from coal, refined petroleum products and natural gas. Many energy inputs into iron and steel making are not flexible because they are part of the production process – metallurgical coal is required to reduce iron ore into pig iron. The modest increase in electricity consumption is mostly from the electricity requirements of capturing the carbon dioxide.

Table 43: Fuel switching in iron and steel manufacturing

	2020	*2030*	*2040*	*2050*
Natural Gas	-1%	1%	1%	2%
Coal	1%	-3%	-5%	-6%
Refined Petroleum Products	0%	1%	2%	3%
Electricity	1%	1%	2%	2%

Economic impact of policy

In 2050, the cost of producing steel increases by $25 per tonne of steel in response to the policy, a 1.5% increase in the total cost (Table 44). The rise in costs is mostly the result of increased capital and energy costs caused by the adoption of carbon capture and storage. Greater electricity and natural gas consumption also contribute to the higher energy costs.

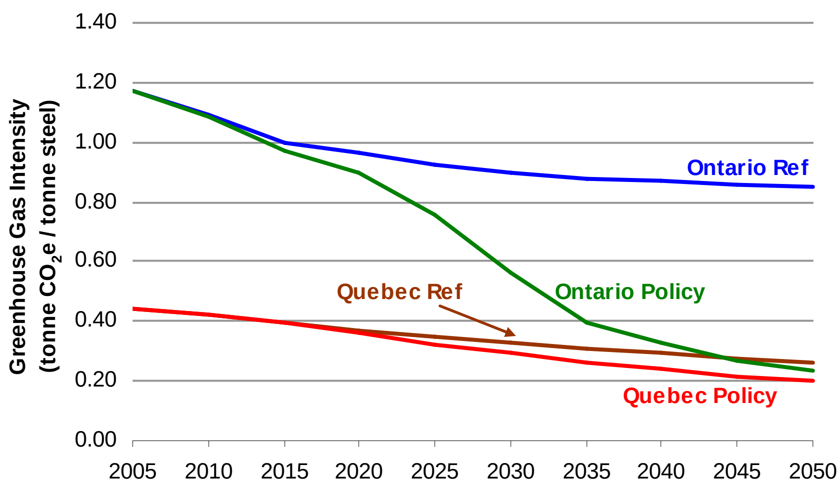
Table 44: Increase in the cost of steel manufacturing[24]

	Increase in Costs (2005$ / tonne of steel)			
	2020	*2030*	*2040*	*2050*
Total Cost	$0.35	$14.68	$22.01	$24.92
Capital Costs	$0.30	$4.71	$6.80	$7.11
Operating & Maintenance Costs	-$1.46	-$0.83	-$0.83	-$0.48
Energy Costs	$1.51	$10.80	$16.04	$18.29

Provincial discussion

The iron and steel industry is concentrated in Ontario and Québec, with the remaining provinces only producing a minimal amount of steel. Ontario manufactures most of its steel in integrated steel mills, while in Québec where electricity prices are cheaper, mini-mills account for the majority of steel production. As seen in Figure 24, the greenhouse gas intensity of steel making is substantially lower in Québec in the reference case, thus limiting opportunities to reduce emissions in that province. The greenhouse gas intensity in Ontario declines by 70% in response to the policy, whereas it declines by 16% in Québec.

Figure 24: Greenhouse gas intensity of iron and steel manufacturing in Ontario and Québec

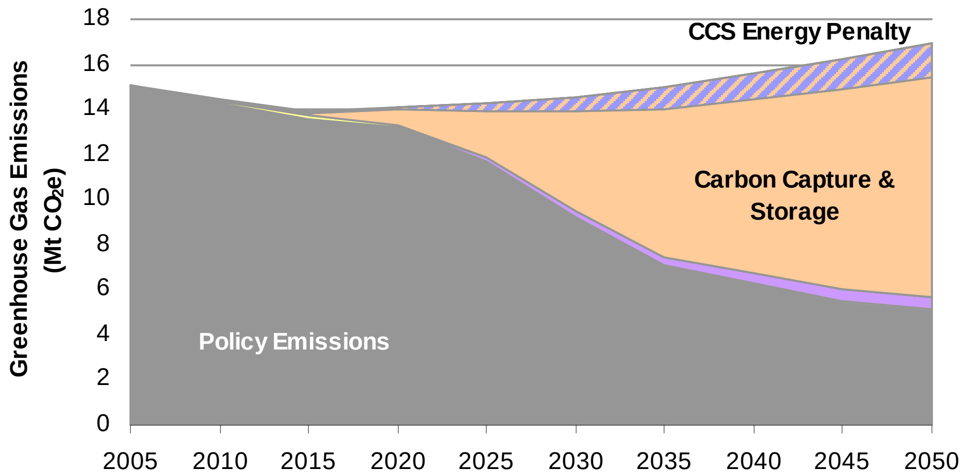


Technology roadmap to low emissions in iron and steel manufacturing

Figure 25 shows the wedge diagram for the iron and steel sector. Virtually all the emissions reductions are the result of the adoption of carbon capture and storage.

[24] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Figure 25: Wedge diagram for iron and steel manufacturing



Carbon capture and storage has the greatest potential for use in integrated steel mills, rather than mini-mills. The combustion of blast furnace gas yields a relatively pure stream of carbon dioxide (about 27% by volume) that can be captured. The cost of carbon capture from the blast furnace gas is uncertain and dependent on the size of the facility, but the cost could be as low as \$35 / tonne CO_2e for large facilities.[25] The capture of carbon dioxide is also possible from the flue gas of the basic oxygen furnace and during the production of process heat. Table 45 shows the penetration of carbon capture and storage in integrated steel mills. Even though the data show a 93% penetration of carbon capture in 2050, it should be interpreted that all mills would employ carbon capture because there are only a few mills in Canada.

Table 45: Penetration of carbon capture and storage in integrated steel manufacturing

	2020	*2030*	*2040*	*2050*
Carbon Capture & Storage	8%	49%	81%	93%

Capital expenditures increase by around 3% in response to the policy, mostly due to increased expenditures on carbon capture equipment (Table 46).

Table 46: Increase in capital expenditures in iron and steel manufacturing

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005\$ Millions)	25	33
Increase in Capital Expenditures (% above the reference case)	3%	3%

Uncertainty in the analysis

A structural change towards producing more steel in mini-mills could reduce emissions, but has not been included in our analysis. In 2005, mini-mills emitted approximately 0.13 tonne CO_2e per tonne of steel produced (although mini-mills are electricity intensive

[25] Intergovernmental Panel on Climate Change, 2005, "Carbon Dioxide Capture and Storage".

and may produce emissions at the point of electric generation), integrated mills emitted around 1.45 t CO_2e per tonne of steel. The industry trend indicates a shift towards producing more steel in mini-mills regardless of the policy and this trend may accelerate in a greenhouse gas constrained future. An increase in mini-mill production would likely reduce the contribution of carbon capture and storage to greenhouse gas abatement, and a greater portion of the reduction would be attained through improved energy efficiency and fuel switching (mini-mills depend mostly on electricity). We note that an increase in mini-mill production may be limited by the availability of scrap steel.

Metal Smelting

Box 7: Key actions by the metal smelting sector

- The sector largely decarbonizes regardless of the policy, mostly due to the uptake of inert anodes in aluminum smelting. The policy accelerates the adoption of inert anodes.

Greenhouse gas emissions from metal smelting are expected to decline from 11 Mt CO_2e in 2005 to 4.8 Mt CO_2e in 2050 in the absence of any greenhouse mitigation policy. The decline in emissions occurs despite an 18% increase in the production from the sector between 2005 and 2050.

The metal smelting sector consists of several smelting industries, of which aluminium smelting is the most significant contributor to greenhouse gas emissions. In 2005, the aluminium smelting sector generated approximately 9 Mt CO_2e; however its contribution to sector emissions declines substantially over the simulation period, from 82% in 2005 to 45% in 2050. The majority of emissions from aluminium smelting are process emissions from the smelting process. Current standard practice in aluminium smelting requires the dissolution of alumina (Al_2O_3) in a fluorine bath, where it is electrically reduced to aluminium (Al) using a carbon anode. In this process, the carbon anode reacts with free oxygen to produce carbon dioxide. Perfluorocarbons, which have 6,500 to 9,000 times the greenhouse warming effect of carbon dioxide, can also be produced in aluminum smelting during anode events, which can occur when the concentration of alumina around the carbon anode falls below approximately 2% by weight. During these events, the temperature around the anode rises and the fluorine bath can react with the anode to produce perfluorocarbons.[26]

The remaining sectors comprise copper, zinc, lead, and magnesium smelting, among other smelting industries. These sectors account for a small amount of emissions, and are not discussed in detail here. We also do not discuss any provincial differences because this sector's contribution to total greenhouse gas emissions is minor.

Environmental impact of policy

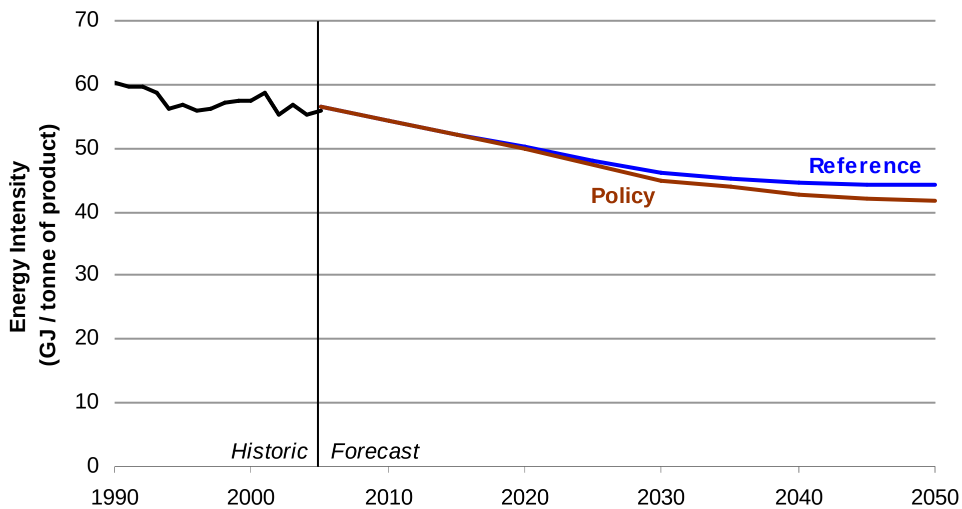
Figure 26 and Figure 27 show the energy and greenhouse gas intensity of metal smelting. In the short-term, the decline in both intensity measures is the result of gradual replacement of Soderberg anodes with pre-baked anodes, which are less energy and

[26] Environment Canada, 2007, "National Inventory Report".

greenhouse gas intensive. The decline in greenhouse gas intensity in the aluminium sector is also partially the result of the adoption of computer controls that reduce the occurrence of anode events. In the long-term, the decline in energy and greenhouse gas intensity in the reference case is primarily the result of the adoption of inert anodes. Inert anodes are not carbon based (metals and ceramics are the most promising material to produce inert anodes) and are expected to be better electricity conductors thereby reducing both energy consumption and greenhouse gas emissions. Inert anodes are still in the experimental phase, but are expected to become available in the near future.[27] The energy and greenhouse gas intensity from other metal smelting declines, but not as dramatically.

The policy causes a slight improvement in energy and greenhouse gas intensity, due largely to a more rapid adoption of inert anodes.

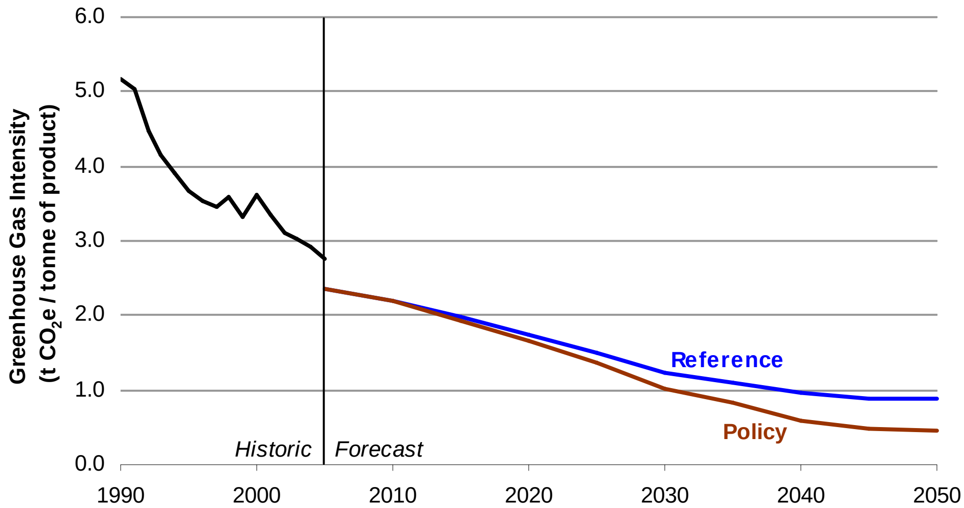
Figure 26: Energy intensity of metal smelting



Source: Historic data are from CIEEDAC, 2008, "Database on Energy, Production and Intensity Indicators for Canadian Industry"

[27] Sadoway, 2001, "Inert Anodes for the Hall-Heroult Cell: The Ultimate Materials Challenge", *JOM*, 34-35.

Figure 27: Greenhouse gas intensity of metal smelting



Source: Historic data are from CIEEDAC, 2008, "Database on Energy, Production and Intensity Indicators for Canadian Industry"

The share of electricity consumption increases in response to the policy, mostly from fuel switching in the smelting of metals other than aluminium (Table 47). Aluminium is already relatively electricity intensive, and there are fewer opportunities to fuel switch.

Table 47: Fuel switching in metal smelting

	2020	2030	2040	2050
Natural Gas	-1%	-2%	-2%	-2%
Coal	0%	-2%	-3%	-4%
Refined Petroleum Products	0%	-1%	-1%	-1%
Electricity	1%	4%	5%	6%

Economic impact of policy

By 2050, the cost of metal smelting increases by $5 per tonne of production ($2005), a negligible increase in the total costs of the sector (Table 48). The increase in cost is relatively evenly divided between an increase in capital and energy costs. The increase in capital costs is mostly attributed to the adoption of inert anodes, whereas the increase in energy costs is mostly attributed to the increase in electricity prices that results from the policy. Operating and maintenance costs decline because inert anodes are forecasted to require less maintenance.

Table 48: Increase in the cost of metal smelting[28]

	Increase in Costs (2005$ / tonne of product)			
	2020	2030	2040	2050
Total Cost	$32.99	$34.24	$15.61	$4.91
Capital Costs	$2.65	$7.89	$8.84	$9.85
Operating & Maintenance Costs	-$2.00	-$6.16	-$13.10	-$15.17
Energy Costs	$32.34	$32.52	$19.87	$10.22

Technology roadmap to low emissions in metal smelting

The adoption of inert anodes and fuel switching to electricity each account for approximately 45% of emissions reductions (see Figure 28). We do not discuss other actions to reduce emissions, because they account for less than 1 Mt CO_2e of reductions.

Figure 28: Wedge diagram for metal smelting

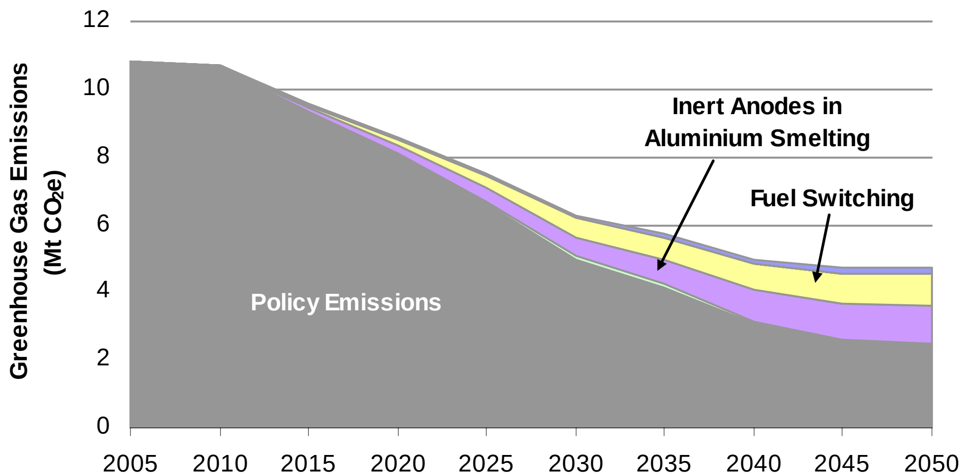


Table 49 shows the penetration of key abatement technologies in the aluminum-smelting sector as a percentage of total installed stock. The policy induces a more rapid adoption of inert anodes, which eliminate most of the carbon dioxide and perfluorocarbons emitted by the industry. By 2050, the majority of aluminum-smelting plants in Canada are projected to use inert anodes.

Table 49: Penetration of key technologies in aluminum smelting

	Policy Penetration of Anodes (%)				Increase due to Policy (%)			
	2020	2030	2040	2050	2020	2030	2040	2050
Pre-baked Anodes with computer Controls	48%	49%	32%	9%	-1%	-6%	-12%	-17%
Inert Anodes	11%	36%	66%	91%	2%	7%	13%	19%

The remaining emissions reductions in the metal smelting sector are mostly from fuel switching to electricity for the production of process heat in the smelting of metals other than aluminum. In total these actions amount to a 1 Mt CO_2e reduction in greenhouse gases in 2050.

[28] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

The policy induces a moderate decline in capital expenditures in the medium-term, due to a small decline in the output from the sector (approximately 2%). In the long-term, output returns to its business-as-usual trajectory but the capital requirements increase from the uptake of inert anodes (Table 50).

Table 50: Increase in capital expenditures in metal smelting

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-8	9
Increase in Capital Expenditures (% above the reference case)	-1%	1%

Uncertainty in the analysis

The key uncertainty with this analysis is whether and when inert anodes for aluminium smelting become available. If inert anodes do not become available and the sector continues to rely on carbon-based anodes, the anticipated emissions reductions from the aluminium sector may not be possible. Perfluorocarbons can be largely abated through improved computer controls, but the sector would still produce a substantial amount of process carbon dioxide due to the degradation of the anodes.

Mineral and Coal Mining

Box 8: Key actions by the mineral and coal mining sectors

- The sector does not play a large role in Canada's total emissions or emissions reductions. Most emissions reductions in this sector are attained through fuel switching to electricity and renewable fuels.

The mineral and coal mining sectors are forecasted to emit 12 Mt CO_2e by 2050, and account for around 1% of Canada's total greenhouse gas emissions. Two end-uses account for 95% of the sectors' greenhouse gas emissions: 1) cleaning or concentrating mineral ores or coal before transport, which requires hot water in some cases and 2) the extraction and transport of ores and coal, which produces combustion emissions. We ignore any provincial discussion for mineral and coal mining because the sector contributes little to Canada's total emissions.

Environmental impact of policy

In the reference case, the energy and greenhouse gas intensity of mineral and coal mining rise in response to accelerated growth rates in Saskatchewan's potash mining sector, which is more energy and greenhouse gas intensive than the mining sectors in other provinces (Figure 29 and Figure 30). The energy and emissions intensity for individual sub-sectors is relatively stable.

The policy induces a 50% decline in greenhouse gas intensity from the reference scenario. This decline is mostly a result of the electrification of hot water production for cleaning systems and the adoption of renewable fuels for extraction and transportation of mineral ores and coal.

Figure 29: Energy intensity of mineral and coal mining

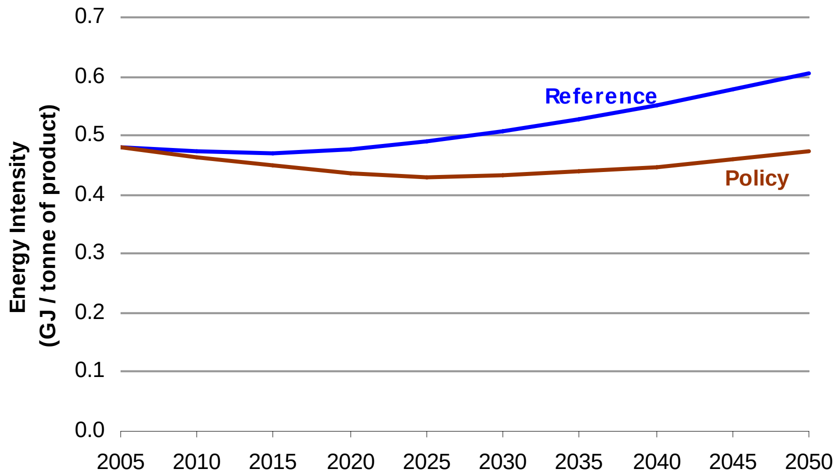
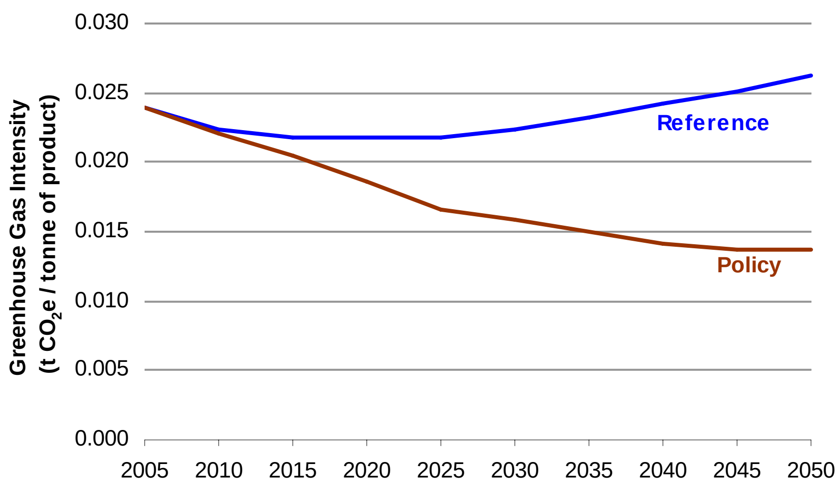


Figure 30: Greenhouse gas intensity of mineral and coal mining



The mining sectors generally switch to electricity and renewable fuels in response to the policy (see Table 51). In some mining operations, electric conveyors may be used instead of diesel motors and electricity can be used to heat water instead of natural gas. Renewable biofuels are used to power trucks and excavators.

Table 51: Fuel switching in mineral and coal mining

	2020	2030	2040	2050
Natural Gas	-6%	-14%	-22%	-27%
Coal	0%	-1%	-2%	-2%
Refined Petroleum Products	-2%	-3%	-4%	-3%
Electricity	6%	15%	24%	29%
Renewable	2%	3%	4%	5%

Economic impact of policy

The financial costs of operation decline by approximately 4%, in response to the policy (see Table 52). Electric motors and heaters have lower capital and maintenance requirements, but have greater energy costs because electricity is more expensive than other fossil fuels on an energy basis.

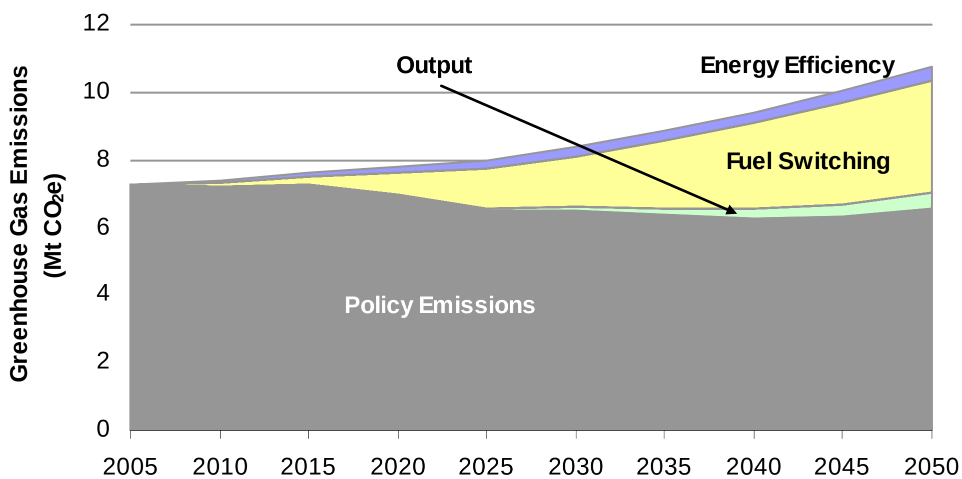
Table 52: Increase in the cost of mineral and coal mining[29]

	Increase in Costs (2005$ / tonne of product)			
	2020	2030	2040	2050
Total Cost	-$0.92	-$1.71	-$2.33	-$2.76
Capital Costs	-$0.69	-$1.29	-$1.79	-$2.13
Operating & Maintenance Costs	-$0.23	-$0.42	-$0.58	-$0.69
Energy Costs	-$0.01	$0.00	$0.05	$0.05

Technology roadmap to low emissions in mineral and coal mining

Figure 31 shows that fuel switching to electricity and renewables accounts for the majority of the reductions in greenhouse gas emissions.

Figure 31: Wedge diagram for mineral and coal mining



By 2050, approximately half of the energy consumption from the major sources of emissions is met by electricity or biodiesel (see Table 53).

Table 53: Zero emissions fuel consumption in mineral and coal mining

	2020	2030	2040	2050
Biodiesel in Extraction and Transportation	28%	32%	36%	47%
Electricity in Cleaning and Concentrating	21%	39%	52%	52%

The capital expenditures from mineral and coal mining increase in response to the policy, due to an expansion of the coal mining sector (see Table 50). The demand for coal increases due to an expansion of electricity generation from coal.

[29] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Table 54: Increase in capital expenditures in mineral and coal mining

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	75	137
Increase in Capital Expenditures (% above the reference case)	3%	4%

Pulp and paper manufacturing

Box 9: Key actions by the pulp and paper manufacturing sector

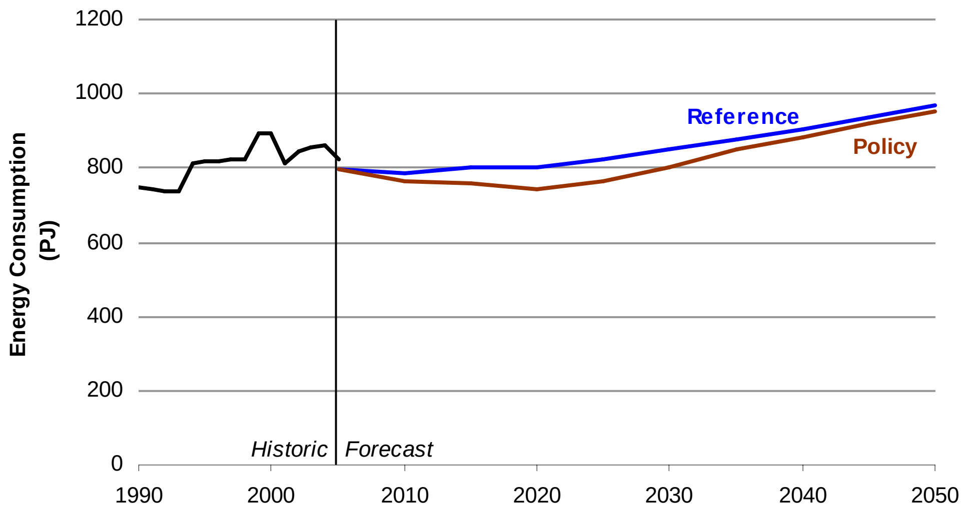
- The pulp and paper sector largely decarbonizes regardless of the policy, due to a shift towards using wood waste material as fuel.

The pulp and paper sector largely decarbonizes in the reference case, where greenhouse gas emissions decline from 7 Mt CO_2e in 2005 to 2 Mt CO_2e in 2050. This decline occurs despite a 37% increase in the output of pulp and paper products. The sector is mostly concentrated in Québec, with smaller sectors in British Columbia and Ontario. The differences among these provinces are relatively small, so we exclude a provincial discussion.

Environmental impact of policy

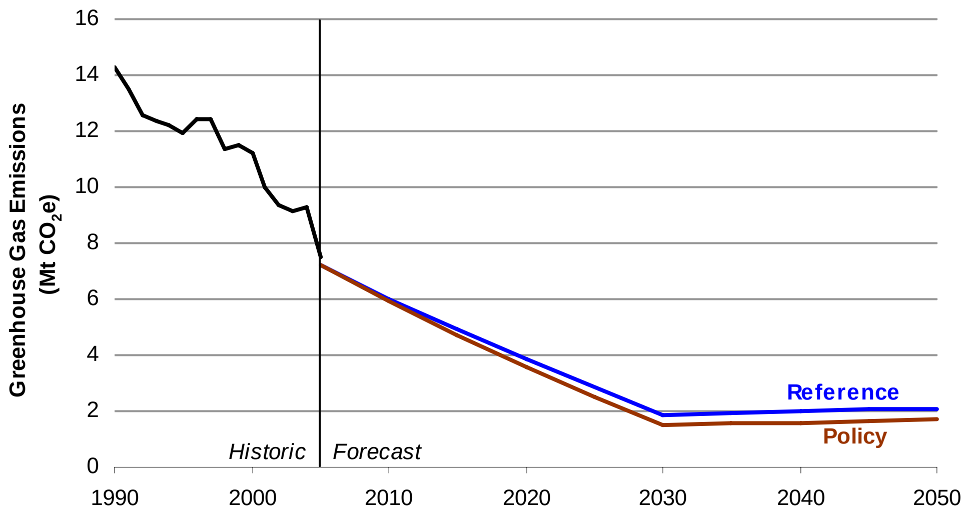
In the reference case, energy consumption and greenhouse gas emissions roughly follow historical trends, with a moderate increase in energy consumption and a significant decline of 70% in greenhouse gas emissions over the simulation period (Figure 32 and Figure 33). The sector has an abundance of waste wood material and by-products from the pulping process (i.e., black liquor) that can be used as fuel. Since 1990, the sector has gradually displaced the consumption of fossil fuels in favour of renewable fuels. In the policy scenario, this trend is accelerated.

Figure 32: Energy consumption from pulp and paper manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 33: Greenhouse gas emissions from pulp and paper manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

The share of renewable fuels increases slightly in response to the policy (Table 55). By 2050 in the policy scenario, renewable fuels supply 95% of the process heat required by the sector.

Table 55: Fuel switching in pulp and paper manufacturing

	2020	*2030*	*2040*	*2050*
Electricity	2%	1%	0%	0%
Renewable	-2%	-1%	1%	1%

Economic impact of policy

The cost of manufacturing pulp and paper products increases modestly in response to the policy, by a fraction of a percent (Table 56). The impacts are minor because the policy merely accelerates an ongoing transition towards a greater consumption of renewable fuels.

Table 56: Increase in the cost of pulp and paper manufacturing[30]

	Increase in Costs (2005$ / tonne of product)			
	2020	*2030*	*2040*	*2050*
Total Cost	$2.90	$5.67	$4.04	$2.21
Capital Costs	-$3.93	-$2.12	$0.05	$0.44
Operating & Maintenance Costs	-$2.30	-$1.20	$0.18	$0.57
Energy Costs	$9.13	$8.98	$3.80	$1.20

Technology roadmap to low emissions in pulp and paper manufacturing

Fuel switching to renewables accounts for most of the emissions reductions of the sector (Figure 34). These actions reduce emissions by 0.4 Mt CO_2e in 2050.

[30] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Figure 34: Wedge diagram for pulp and paper manufacturing

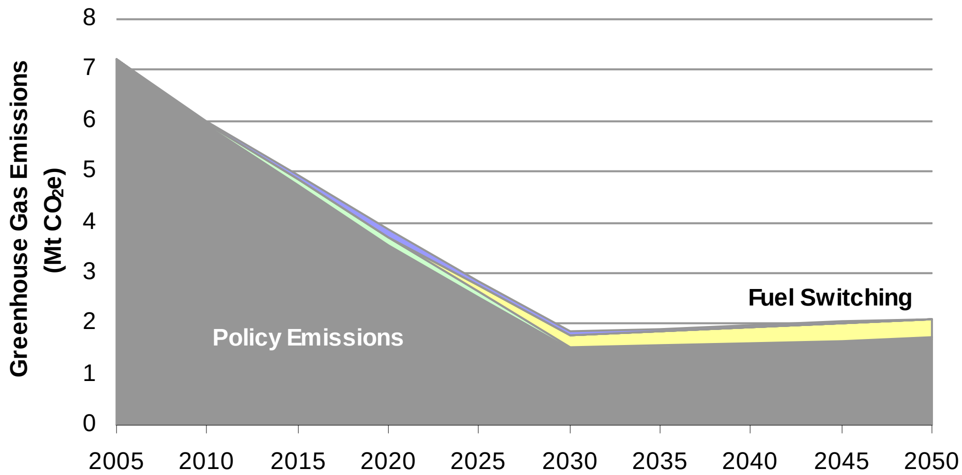


Table 57 shows heat production from the renewable waste fuels as a percentage of total heat production, excluding the heat produced in lime kilns. By 2030, most heat production comes from renewable fuels.

Table 57: Heat production from wood waste and spent pulping liquor

	2020	*2030*	*2040*	*2050*
Heat Production from Renewable	83%	98%	98%	98%

Capital expenditures decline slightly in response to the policy (see Table 58), due to a modest reduction in output.

Table 58: Increase in capital expenditures in pulp and paper manufacturing

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-54	-33
Increase in Capital Expenditures (% above the reference case)	-3%	-2%

Other Manufacturing

Box 10: Key actions by the other manufacturing sector

- The other manufacturing sector reduces its emissions by switching to electricity from fossil fuels.

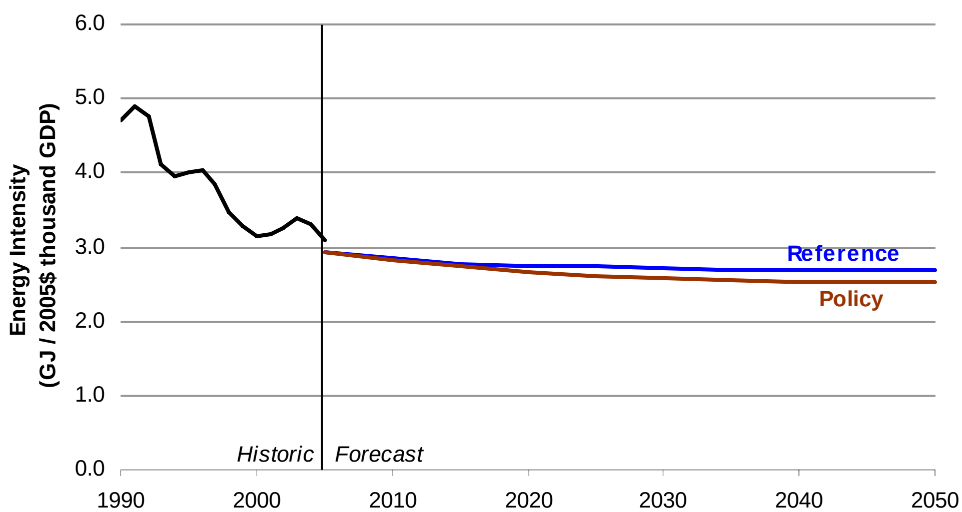
The gross domestic product of the other manufacturing sector grows over the simulation period by 160% to $472 billion in 2050. By 2050, the other manufacturing sector is projected to generate 47 Mt CO_2e, about 5% of Canada's projected greenhouse gas emissions. The production of process heat and hot water account for the majority of greenhouse gas emissions from the sector, with process heating contributing approximately 79% and water heating accounting for the most of the remainder. This section excludes a provincial discussion.

Environmental impact of policy

In the reference case, energy and greenhouse gas intensity remain fairly stable despite significant historical declines (Figure 35 and Figure 36). This discrepancy is likely because gross domestic product is used as the measure of the sector's output, rather than physical production. Measures of energy and emissions intensity based on gross domestic product are imperfect because energy consumption and emissions are more closely linked to physical output (i.e., the number of cars built rather than the value-added by each car). Additionally, energy intensity can decline in response to structural shifts within the sector. If a sub-sector with low intensity begins to contribute more to gross domestic product, the intensity from the sector as a whole would decline. We have not examined the degree to which these factors have contributed to the historic decline in energy and greenhouse gas intensity.

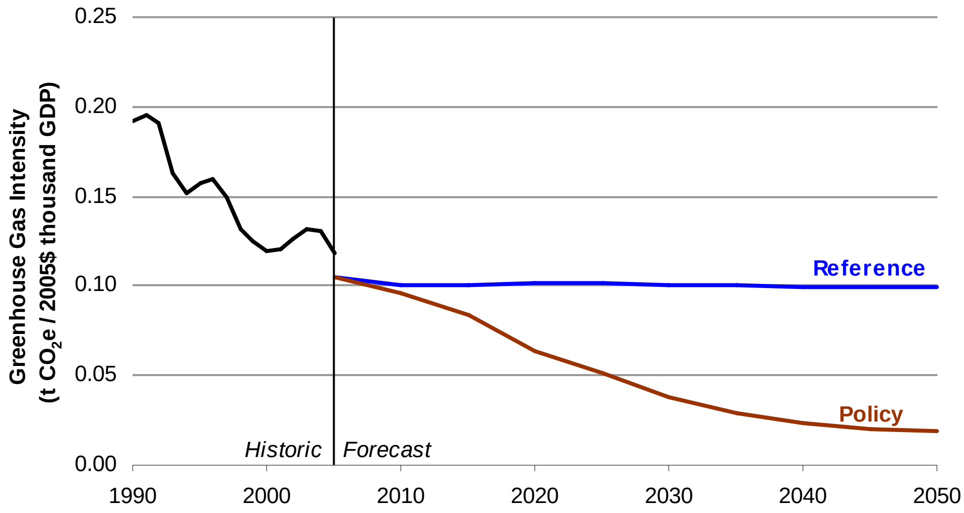
In the policy scenario, energy intensity declines slightly from the reference case projection, while greenhouse gas intensity declines by 82% from the reference case projection by 2050. The decline in greenhouse gas intensity is primarily due to the adoption of technologies that consume electricity rather than fossil fuels.

Figure 35: Energy intensity of other manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 36: Greenhouse gas intensity of other manufacturing



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

The sector generally switches from natural gas and refined petroleum products to electricity, in response to the policy (see Table 59). The share of renewable energy in the form of biomass also rises as the use of wood-fuelled boilers increases.

Table 59: Fuel switching in other manufacturing

	2020	*2030*	*2040*	*2050*
Natural Gas	-19%	-34%	-42%	-45%
Coal	0%	-1%	-1%	-2%
Refined Petroleum Products	-5%	-7%	-8%	-7%
Electricity	21%	38%	47%	50%
Renewable	3%	4%	4%	4%

Economic impact of policy

Table 60 shows how capital, operating and fuel costs contribute to total costs in the other manufacturing sector. The total increase in cost is just under 3%, and the rise in energy costs accounts for the entire increase, while capital and operating costs decline. These changes are due to the uptake of electric heating systems, which require less maintenance and have lower capital investments, but have higher energy costs because electricity is more expensive per unit of energy produced. The energy costs are further increased by the rise in the price of electricity caused by the policy.

Table 60: Increase in cost of other manufacturing[31]

	Increase in Costs (2005$/thousand 2005$ GDP)			
	2020	*2030*	*2040*	*2050*
Total Cost	$3.04	$6.18	$8.03	$8.51
Capital Costs	-$0.01	-$0.08	-$0.13	-$0.12
Operating & Maintenance Costs	-$0.01	-$0.05	-$0.06	-$0.06
Energy Costs	$3.07	$6.30	$8.22	$8.69

Technology roadmap to low emissions in other manufacturing

Figure 37 illustrates the actions that contribute to the decline in greenhouse gas emissions in the other manufacturing sector: fuel switching accounts for almost all of the emissions reductions.

Figure 37: Wedge diagram for other manufacturing

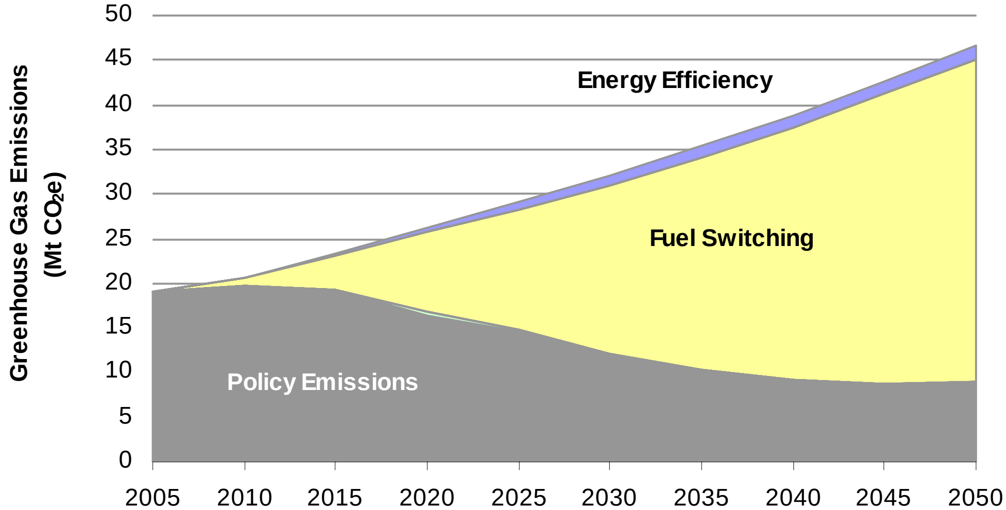


Table 61 and Table 62 display the penetration rates of key abatement technologies as a percentage of total installed stock. In 2050, electric and biomass fuelled heat systems show an overall penetration rate of nearly 69%, with electric systems comprising nearly 62% of that total. Water heating constitutes a smaller portion of total emissions within the other manufacturing sector, but show a more aggressive – by 2050 electric water heaters meet virtually all the demand for hot water.

Table 61: Penetration of other manufacturing process heat systems

	Technology Penetration (% of total stock)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Electric Heating Systems	31.7%	48.2%	59.1%	61.9%	18.8%	34.9%	45.6%	48.4%
Biomass Heating Systems	7.2%	7.5%	7.4%	7.5%	3.0%	3.4%	3.4%	3.5%

[31] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Table 62: Penetration of other manufacturing water heating systems

	Technology Penetration (% of total stock)				Increase due to Policy (%)			
	2020	2030	2040	2050	2020	2030	2040	2050
Electric Water Heating	79.3%	98.4%	99.2%	99.2%	38.0%	57.1%	58.2%	58.6%

Table 63 shows that the capital expenditures by the sector decline in response to the policy. Expenditures decline due to a modest decline in output and the investment in electric boilers and heaters which are cheaper relative to those using fossil fuels.

Table 63: Increase in capital expenditures of other manufacturing

	Medium-Term (2011-2030)	Long-term (2031-2050)
Increase in Annual Capital Expenditures (2005$ Millions)	-33	-42
Increase in Capital Expenditures (% above the reference case)	-3%	-2%

Electricity generation

Box 11: Key actions by the utility electricity generation sector

- Electricity supply expands to meet an increased demand for electricity in the policy scenario. By 2050, electricity supply reaches 1,700 TWh per year.
- Carbon capture and storage is the key action to reduce the direct greenhouse gas emissions of the sector.
- The expansion of electric generation from renewable sources (especially hydro and wind) reduces greenhouse gas emissions at the point of electricity consumption. Most new renewable capacity is added in provinces already dependent on generation from renewables – British Columbia, Manitoba and Québec – and does not reduce emissions at the point of electricity production. The expansion of electricity generation from renewables enables other sectors (e.g., residential and commercial) to reduce fossil fuel consumption by switching to electricity.

In the absence of any mitigation policy, the greenhouse gas emissions from the utility generation of electricity are expected to grow from 129 Mt CO_2e in 2005 to 170 Mt CO_2e by 2050. The projected rise is mainly the result of an increase in electricity generation from approximately 600 TWh in 2005 to over 1,100 TWh in 2050. Over this period, generation from fossil fuels remains relatively stable – generation from coal and natural gas remain at approximately 18% and 5% between 2005 and 2050, respectively.

More than in most other sectors of the economy, the electricity generation sector has substantial differences among provinces. British Columbia, Manitoba and Québec rely heavily on hydroelectricity. Alberta and Saskatchewan do not have the same potential for hydroelectric power, but have an abundance of fossil fuels – especially coal. In Ontario, nuclear generation is projected to contribute 43% of total generation by 2050, while coal and renewables (mostly hydroelectricity with some wind) account for 27% and 26%, respectively. The Ontario government has stated that it will close all coal plants in Ontario by 2014, so we have simulated the closure of all single cycle coal plants, but allowed the competition of new coal plants with improved energy efficiency and environmental controls.[32] In the Atlantic Provinces, electric generation by utilities is expected to be 77% hydroelectric by 2050 due to production from Labrador, which is mostly exported to Québec. The Atlantic Provinces also generate electricity from coal, nuclear, and a small amount of natural gas in 2050. Because provincial differences in this sector are significant, we provide a more detailed discussion at a provincial level.

Environmental impact of policy

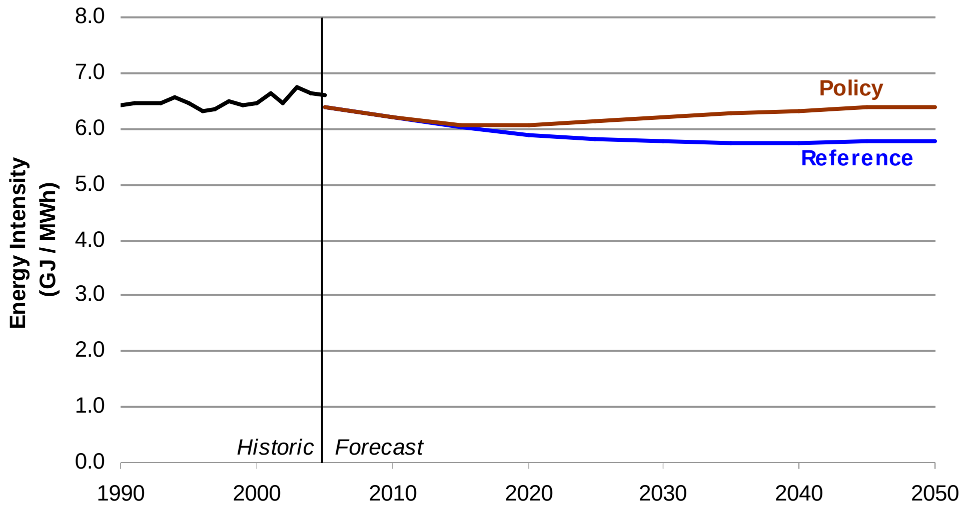
In the reference case, energy and greenhouse gas intensity decline over the simulation period (Figure 38 and Figure 39).[33] Although electricity generation by fuel remains relatively unchanged between 2005 and 2050, single cycle coal and natural gas plants are gradually replaced with advanced coal technologies and combined cycle natural gas plants. The decline in greenhouse gas intensity in the reference case is largely due to the improvement in energy intensity.

In the policy scenario, greenhouse gas intensity declines to 0.02 tonnes CO_2e / MWh in 2050, an 83% decline from the reference case projection, while energy intensity increases by 10%. The decline in greenhouse gas intensity is primarily the result of an increase in carbon capture and storage in Alberta, Saskatchewan and Ontario. The addition of new renewable capacity in British Columbia, Manitoba and Québec has little impact on greenhouse gas intensity, because these provinces have low emissions regardless of the policy. Energy intensity is higher in the policy scenario due to the energy penalty associated with carbon capture and storage.

[32] Ontario Ministry of Energy and Infrastructure, 2008, http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&body=yes&news_id=176.

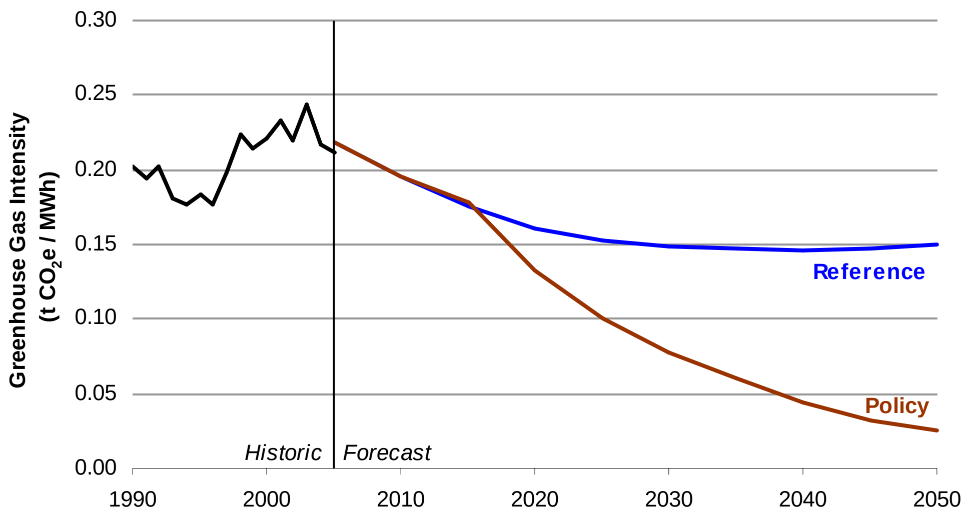
[33] Renewable electricity generation is assumed to require 1 GJ of energy (e.g., wind, hydro) for each GJ of electricity generated. Nuclear electricity generation is assumed to require 1 GJ of energy for each GJ of thermal energy generated. See International Energy Agency, 2007, “Energy Balances of OECD Countries: 2004-2005”.

Figure 38: Energy intensity of utility electricity generation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 39: Greenhouse gas intensity of utility electricity generation



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Table 64 shows the greenhouse gas intensity for Alberta, Saskatchewan, Ontario and the Atlantic provinces. We exclude the provinces that rely mostly on hydroelectric generation because their greenhouse gas intensities are low in the reference case and remain so after the policy's implementation (approximately 0.01 tonnes CO_2e / MWh in 2005). The greenhouse gas intensities for all provinces are available in Appendix A. The adoption of carbon capture and storage is the most important action to reduce greenhouse gas intensity in Alberta and Saskatchewan. In Ontario and the Atlantic provinces, carbon capture and storage also plays a significant role, but an increase in electricity production from renewable sources also contributes to the reduction in greenhouse gas intensity.

Table 64: Greenhouse gas intensity of electric generation by utilities by province

	Greenhouse Gas Intensity (t CO_2e / MWh)				*Decline due to Policy (t CO_2e / MWh)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Alberta	0.51	0.27	0.15	0.08	0.20	0.37	0.43	0.46
Saskatchewan	0.54	0.30	0.15	0.09	0.22	0.43	0.54	0.59
Ontario	0.13	0.09	0.05	0.03	0.02	0.08	0.14	0.18
Atlantic	0.13	0.04	0.02	0.01	0.03	0.07	0.09	0.11

Table 65 shows the increase in electricity generation by fuel that results from the policy's implementation. Both the electricity generation using carbon capture and the generation from renewables rise in response to the policy – the generation using carbon capture and generation from renewables account for 52% and 37% of the increase, respectively.

Table 65: Increase in generation of electricity by fuel and generation type (TWh)

	2020	*2030*	*2040*	*2050*
Renewable	91	187	256	304
Nuclear	25	59	80	85
Coal	5	-37	-106	-188
Natural Gas	-11	-28	-41	-50
Carbon Capture & Storage	57	183	309	429
Total Increase in Generation	167	364	498	579

Economic impact of policy

Table 66 shows the increase in the cost of electricity generation. Alberta and Saskatchewan show the largest increase in the cost of producing electricity, mostly because their electricity sectors are projected to be more greenhouse gas intensive and therefore require greater capital investments to decarbonize than those in other provinces. The rise in electricity costs is more modest in the remaining provinces. In the predominately hydroelectric provinces, the greater costs are mostly due to the substantial increase in electric capacity, which requires new capital investments. British Columbia shows greater increases in the cost of electric generation due to additions of small hydroelectric plants (which are relatively more costly than large plants).

Table 66: Increase in the cost of electricity generation by province

	Increase in Costs (2005$ / MWh)			
	2020	*2030*	*2040*	*2050*
British Columbia	$11.15	$12.76	$11.13	$8.71
Alberta	$15.29	$22.09	$19.79	$18.32
Saskatchewan	$10.84	$16.11	$17.51	$18.50
Manitoba	$6.28	$7.46	$6.24	$4.83
Ontario	$5.40	$7.69	$8.10	$8.63
Québec	$4.01	$5.61	$5.13	$4.19
Atlantic	$2.22	$6.71	$7.55	$8.27
Canada (weighted by generation)	$8.60	$13.54	$13.55	$12.42

Table 67 separates the total costs into capital, operating and energy costs. An increase in capital expenditures contributes most significantly to the rise in costs, whereas energy cost increases are modest. The adoption of carbon capture and storage increases coal consumption, but the price for coal is relatively low. Additionally, the adoption of renewable electricity generation reduces energy costs.

Table 67: Increase in the cost of electricity generation[34]

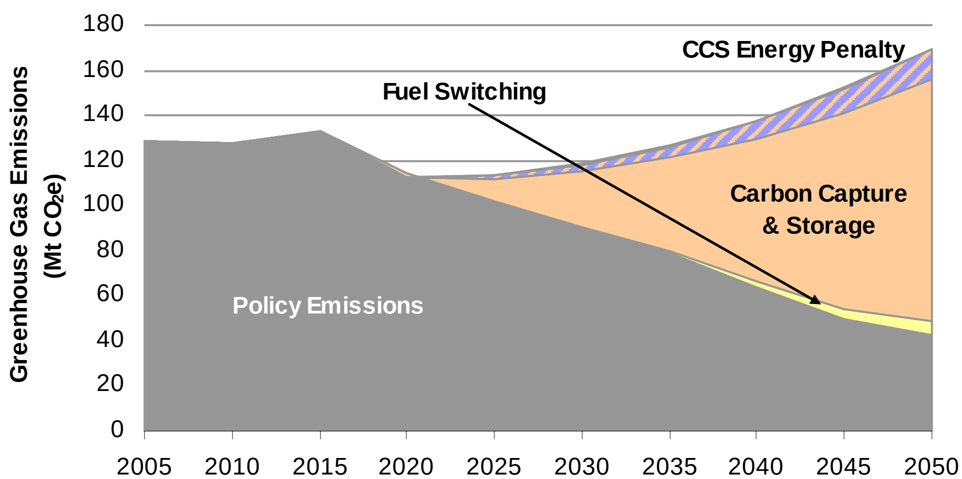
	Increase in Costs (2005$ / MWh)			
	2020	*2030*	*2040*	*2050*
Total Cost	$8.60	$13.54	$13.55	$12.42
Capital Costs	$7.25	$10.34	$9.68	$8.28
Operating & Maintenance Costs	$0.73	$1.28	$1.59	$1.79
Energy Costs	$0.61	$1.92	$2.27	$2.35

Technology roadmap to low emissions in electricity generation

Carbon capture and storage is the most important action to reduce greenhouse gas emissions in the electricity generation sector (see Figure 40). Carbon capture (excluding transport) at integrated gasification combined cycle coal and combined cycle natural gas plants is expected to cost between $25 and $100 (2005$) per tonne of CO_2e avoided, depending on fuel and whether the plant is used for base load or peak load demand. The emissions price in the policy scenario should be sufficient to prevent any new construction of fossil fuel plants without carbon capture. Furthermore, it is likely to induce many utilities to retrofit existing fossil fuel plants.

The figure only shows a small reduction from fuel switching to renewables, even though generation from renewable sources increases by 43% in the policy scenario. Most renewable capacity is added in provinces that already have low greenhouse gas intensity, and does not reduce the direct emissions from the sector. However, the expansion of the electricity sector in these provinces enables other sectors (e.g., residential and commercial sectors) to reduce fossil fuel consumption in favour of electricity consumption.

Figure 40: Wedge diagram for utility electricity generation



[34] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Table 68 shows the generation from zero- and low-emission technologies in the policy scenario. By 2050, the electricity stock has been almost completely de-carbonized. Generation by hydroelectric power plants accounts for the majority of generation (52%). Integrated gasification combined cycle coal plants and combined cycle natural gas turbines with carbon capture (IGCC CCS and NGCC CCS) account for 17% and 7% of total installed capacity, respectively. The pulverized coal plants with carbon capture (PC CCS) are existing facilities that have been retrofitted.

Table 68: Generation by plant type

	Total Generation (TWh)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Hydro	505	633	759	890	17%	31%	37%	39%
Wind	33	63	91	110	84%	118%	104%	77%
Other Renew	3	7	10	13	117%	150%	144%	134%
Nuclear	124	168	204	232	26%	54%	64%	57%
PC CCS	11	23	28	30	NA	NA	NA	NA
IGCC CCS	26	100	195	300	NA	NA	NA	NA
NGCC CCS	25	71	105	126	NA	NA	NA	NA
Total Generation	868	1,166	1,445	1,712	24%	45%	53%	51%

Table 69, Table 70 and Table 71 show electricity generation by plant type in different regions in Canada. Carbon capture plays a significant role in Alberta and Saskatchewan, while the hydroelectric provinces generally increase generation from hydropower in response to the policy. Ontario and the Atlantic provinces show increases in generation from fossil energy using carbon capture and storage, nuclear energy and renewable energy.

Table 69: Generation by plant type in Alberta and Saskatchewan

	Total Generation (TWh)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Hydro	12	17	22	27	30%	65%	87%	99%
Wind	6	12	17	20	111%	159%	146%	106%
Other Renew	0	1	1	2	139%	215%	239%	272%
Nuclear	0	0	0	0	NA	NA	NA	NA
PC CCS	8	16	19	20	NA	NA	NA	NA
IGCC CCS	15	54	104	158	NA	NA	NA	NA
NGCC CCS	15	41	61	72	NA	NA	NA	NA
Total Generation	137	198	256	304	40%	80%	102%	103%

Table 70: Generation by plant type in Ontario and the Atlantic Provinces

	Total Generation (TWh)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Hydro	103	134	166	196	21%	44%	59%	69%
Wind	19	35	49	60	72%	114%	104%	80%
Other Renew	1	2	3	4	130%	212%	204%	206%
Nuclear	115	157	193	220	26%	55%	66%	59%
PC CCS	3	7	9	10	NA	NA	NA	NA
IGCC CCS	11	46	90	142	NA	NA	NA	NA
NGCC CCS	7	22	32	39	NA	NA	NA	NA
Total Generation	317	444	562	674	28%	57%	65%	61%

Table 71: Generation by plant type in British Columbia, Manitoba and Québec

	Total Generation (TWh)				*Increase due to Policy (%)*			
	2020	*2030*	*2040*	*2050*	*2020*	*2030*	*2040*	*2050*
Hydro	390	483	571	668	16%	27%	30%	31%
Wind	7	17	25	31	99%	103%	83%	58%
Other Renew	2	4	5	7	108%	118%	106%	89%
Nuclear	8	10	12	12	26%	40%	39%	28%
PC CCS	0	0	0	0	NA	NA	NA	NA
IGCC CCS	0	0	0	0	NA	NA	NA	NA
NGCC CCS	2	8	12	16	NA	NA	NA	NA
Total Generation	414	524	627	735	17%	28%	31%	30%

Capital expenditures rise to meet the growth in the demand for electricity that results from the policy, as well as a more capital intensive electricity stock (Table 72).

Table 72: Increase in capital expenditures for utility electricity generation

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	12,512	9,553
Increase in Capital Expenditures (% above the reference case)	148%	67%

Uncertainty in the analysis

In this analysis, we have constrained the construction of new nuclear plants to provinces that had nuclear plants in 2005, and constrained the expansion of nuclear generation in provinces with nuclear power. We assume that the adoption of nuclear generation technologies will be a political rather than economic decision. If the constraints on nuclear power are relaxed, it could substantially contribute to emissions reductions. The adoption of nuclear power would likely reduce the contribution of carbon capture and storage.

We have not simulated how changes in the inter-provincial or international trade of electricity could contribute to the emissions reductions from the province. It may be possible for provinces with hydroelectric potential to increase generation and export excess production to provinces with higher greenhouse gas intensities.

Petroleum refining

Box 12: Key actions by the petroleum refining sector

- The output of refined petroleum products declines in the policy scenario due to increases in biofuel consumption in the transportation sector. The decline in output is responsible for most of the emissions reductions.
- The remaining emissions reductions are attained through the adoption of carbon capture and storage.

In the absence of any greenhouse gas mitigation policy, the petroleum refining sector is expected to play an increasingly important role in Canada's total greenhouse gas emissions. Greenhouse gas emissions from petroleum refining are expected to rise in the reference case from approximately 19 Mt CO_2e in 2005 to 32 Mt CO_2e by 2050, when it would account for 3% of Canada's projected greenhouse gas emissions.

The petroleum refining sector transforms crude oil into gasoline and diesel, mainly for use as transportation fuels. Demand for refining is therefore linked to demand for fuels from transportation – if transportation becomes more efficient or fossil substitutes such as ethanol become available in significant quantity at a reasonable cost, demand for petroleum products will fall.

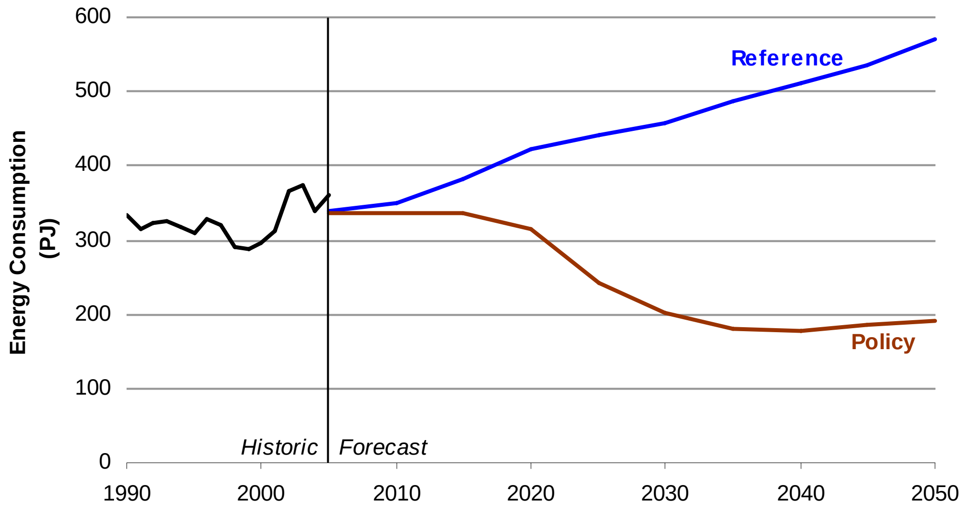
Crude oil comes in variable "grades", generally classed as light, medium, heavy and synthetic. Lighter crude has less carbon and more hydrogen, and heavy crude the opposite. Lighter crude is more similar to the final products (i.e., gasoline and diesel) so it is less costly and less energy intensive to refine. But as light crude deposits have been depleted worldwide, there is a general trend towards use of heavier crudes, which are more plentiful. Much of Canada's remaining known onshore crude is heavy, and the amount of heavy crude to be processed in Canada is projected to increase significantly.

The process of refining divides into four main processes: 1) distillation (separation of the components of crude by variable volatility); 2) cracking (breaking of longer, less useful carbon chains into shorter chains); 3) coking (reduction of the carbon content of crude through direct removal); and 4) hydrotreating (the addition of hydrogen to carbon chains to produce useful products like gasoline). The amount of each process necessary depends on the desired end product, but heavier crudes generally require more cracking, coking and hydrotreating. All of these processes require significant amounts of process heat.

Environmental impact of policy

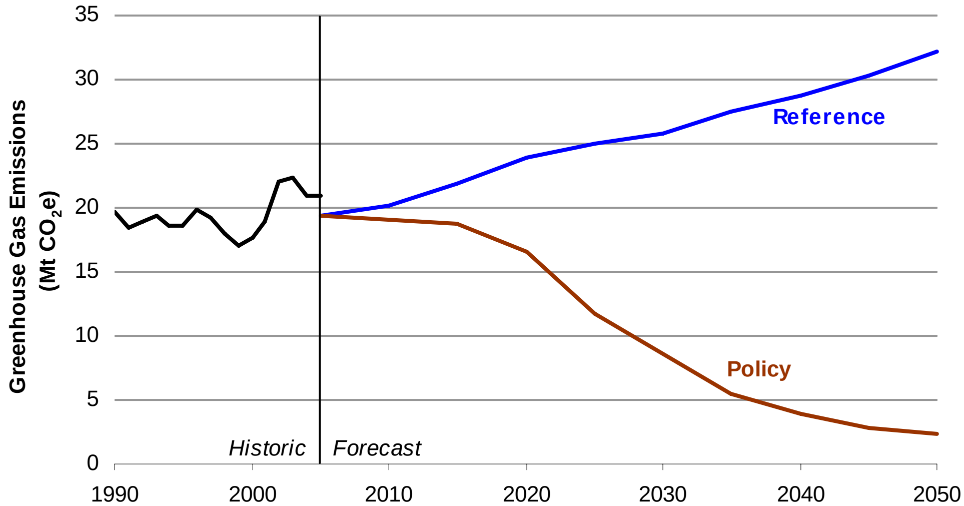
The increase in energy and greenhouse gas emissions in the reference case is the result of increased demand for petroleum products, in addition to the ongoing switch from lighter to heavier crudes (Figure 41 and Figure 42). Both energy consumption and greenhouse gas emissions decline in the policy scenario, mostly due to an increase in biofuel demand from transportation and an associated decline in the demand and supply of petroleum products. By 2050 in the policy scenario, the output of refined petroleum is 65% lower than in the reference projection. The adoption of carbon capture and storage also contributes to the decline in greenhouse gas emissions.

Figure 41: Energy consumption from petroleum refining



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

Figure 42: Greenhouse gas emissions from petroleum refining



Source: Historic data are from NRCan, 2008, "Comprehensive Energy Use Database".

While the reduction in output and the use of CCS contribute to most of the emissions reductions, fuel switching to electricity modestly reduces greenhouse gas emissions. Table 73 shows that natural gas use falls about 18% by 2050, while electricity use rises by about 22%.

Table 73: Fuel switching in petroleum refining

	2020	2030	2040	2050
Natural Gas	-3%	-7%	-14%	-18%
Refined Petroleum Products	-1%	-1%	0%	2%
Electricity	4%	8%	18%	22%
Other	0%	0%	-4%	-6%

Economic impact of policy

The most important impact of the policy on refining costs is on purchased energy, specifically natural gas and electricity. As the sector demands more electricity and the price for electricity increases in the policy scenario, the energy costs from the sector rise. Overall, the cost of refining petroleum increase by 1.5%.

Table 74: Increase in the cost of petroleum refining[35]

	Increase in Costs (2005¢ / L RPP)			
	2020	2030	2040	2050
Total Cost	0.1	0.1	0.6	1.0
Capital Costs	0.0	0.0	0.1	0.1
Operating & Maintenance Costs	0.0	0.0	0.0	0.0
Energy Costs	0.1	0.2	0.6	0.8

Provincial discussion

Canada's refining capacity is concentrated in Alberta and Saskatchewan – which mainly process heavy crude but also some synthetic light crude – and Ontario and Québec – which process imported light crude from Norway, the United Kingdom and other oil exporting countries. Refining in Canada mainly meets domestic transportation demand; and this demand and associated supply is projected to fall in response to the policy.

Technology roadmap to low emissions in petroleum refining

The decline in output from the petroleum refining accounts for over 50% of the sector's emissions reductions in 2050, while carbon capture and storage accounts for approximately 35% (see Figure 43). As discussed above, the decline in output is mostly due to renewable fuel consumption in the transportation sector.

[35] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Figure 43: Wedge diagram for the petroleum refining sector

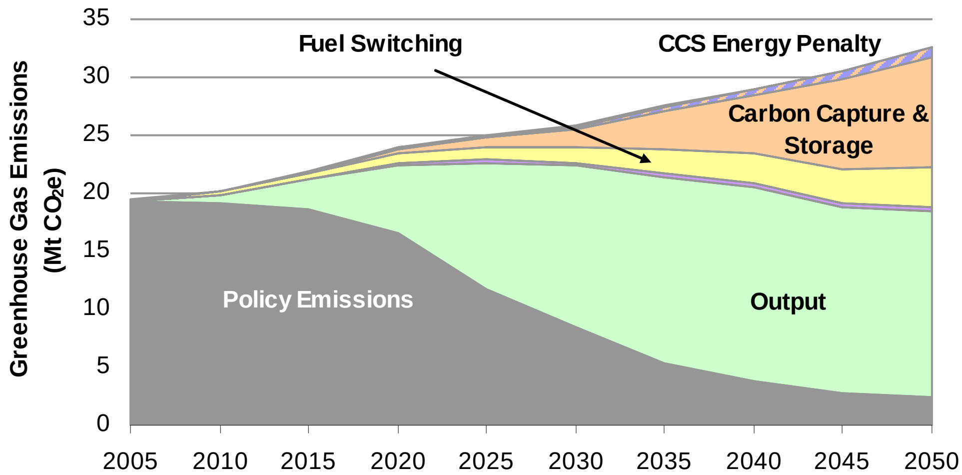


Table 75 shows the penetration of carbon capture and storage in petroleum refining. By 2050, most process heat – 86% – is produced using capture equipment.

Table 75: Penetration of carbon capture and storage

	2020	*2030*	*2040*	*2050*
Carbon Capture & Storage	5%	21%	63%	86%

The reduction in demand for refined petroleum products has the largest impact on the capital expenditures of the sector. Capital expenditures decline by approximately 55% in response to the policy.

Table 76: Increase in capital expenditures of petroleum refining

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	-270	-399
Increase in Capital Expenditures (% above the reference case)	-55%	-60%

Petroleum crude production

Box 13: Key actions by the petroleum crude sector

- The petroleum crude sector is forecasted to expand considerably due to the development of Alberta's oil sands. By 2050, the sector is expected to produce 190 Mt CO_2e in the absence of any mitigation policy.
- The key action to reduce greenhouse gas emissions is the adoption of carbon capture and storage, which contributes to 85% of the sector's greenhouse gas emissions reductions.
- Hydrogen production in oil sands upgraders may be an early opportunity for adopting carbon capture and storage.

The petroleum extraction sector is expected to play an increasingly important role in Canada's total greenhouse gas emissions. In the absence of any mitigation policy, the greenhouse gas emissions from petroleum extraction are expected to rise from approximately 66 Mt CO_2e in 2005 to 190 Mt CO_2e by 2050, which would account for 17% of Canada's projected greenhouse gas emissions in 2050. The projected increase in emissions is partially due to a substantial growth in petroleum production, which increases from 2.6 million barrels per day in 2005 to 7.0 million barrels per day in 2050. The sector is also projected to become more greenhouse gas intensive over the period, as the conventional production of petroleum declines and unconventional production from Alberta's oil sands increases. By 2050, the production of petroleum from oil sands (which includes synthetic crude oil and blended bitumen) is projected to reach 6.6 million barrels per day and emit 185 Mt CO_2e per year.

Within the oil sands sector, the main source of greenhouse gas emissions is from the production of process heat for oil sands upgrading and bitumen extraction from in-situ operations. In 2000, the production of process heat for oil sands upgrading accounted for approximately 78% of the greenhouse gas emissions from oil sands upgrading. Most of the remaining greenhouse gas emissions are process emissions from the production of hydrogen in oil sands upgrading, which accounted for approximately 14% of total upgrading emissions in 2000.[36] Most of the emissions from the conventional production of petroleum are fugitive emissions from oil well operations.

Environmental impact of policy

In the reference case, both the energy and greenhouse gas intensity of petroleum extraction increases until 2020, and declines thereafter (Figure 44 and Figure 45). The rise in energy and greenhouse gas intensity until 2020 is the result of the projected increase in unconventional oil production relative to conventional production. After 2020, unconventional production dominates the industry, and energy and greenhouse gas intensity declines due to improving energy efficiency of unconventional production.

In the policy scenario, energy intensity increases as a result of the policy's implementation. Carbon capture and storage accounts for the majority of the decline in greenhouse gas intensity, although capturing carbon dioxide requires greater energy requirements and increases the energy intensity of petroleum production. The greenhouse gas intensity of oil production is projected to decline from approximately 0.07 tonnes CO_2e per barrel in 2005 to 0.015 tonnes CO_2e per barrel in 2050. The intensity figures for each sub-sector within the petroleum crude sector (i.e., the production of conventional crude, synthetic crude and blended bitumen) are available in Appendix A.

[36] Canadian Association of Petroleum Producers, 2004, "A national inventory of greenhouse gas, criteria air contaminant and hyrogen sulphide emissions by the upstream oil and gas industry".

Figure 44: Energy intensity of petroleum crude production

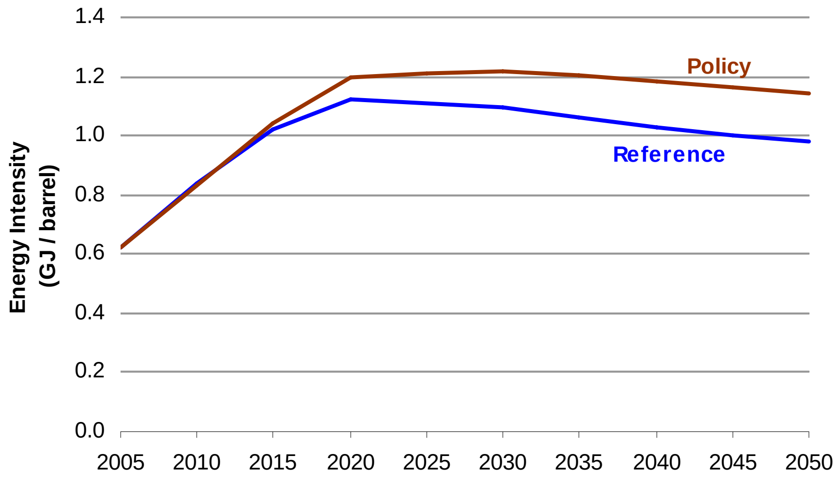
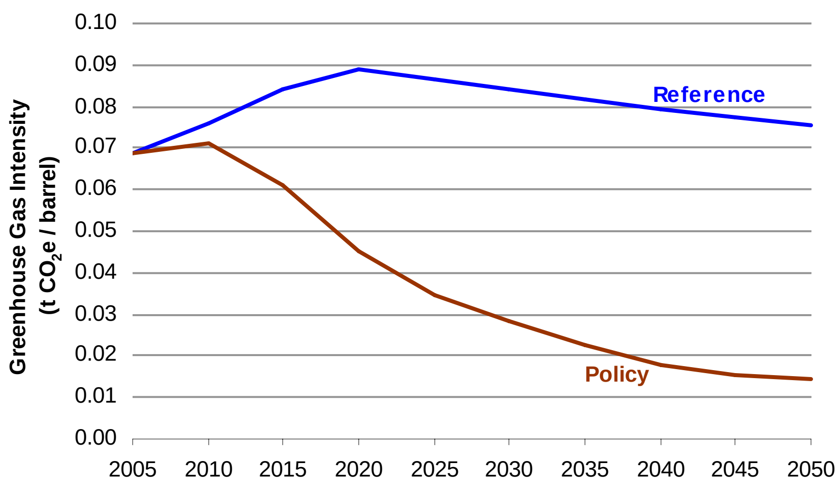


Figure 45: Greenhouse gas intensity of petroleum crude production



The amount of fuel switching is relatively modest in comparison to other sectors (see Table 77). In general, the sector switches from refined petroleum products to electricity. We have excluded the option for the industry to produce process heat and electricity from nuclear energy because the decision is more political than economic. However, nuclear energy could be an option in Alberta's oil sands.

Table 77: Fuel switching in petroleum crude production

	2020	*2030*	*2040*	*2050*
Natural Gas	-1%	-1%	-1%	-1%
Coal	0%	-1%	-1%	-1%
Refined Petroleum Products	-1%	-2%	-4%	-5%
Electricity	2%	3%	5%	6%
Nuclear	0%	0%	0%	0%

Economic impact of policy

In the policy scenario, the cost of oil production rises by $3.23 per barrel, a 14% increase (Table 78). The increase in the cost of producing oil is primarily a result of the adoption of carbon capture and storage. Carbon capture and storage requires greater capital investments and energy costs due to higher energy intensity. The production of synthetic crude from oil sands upgrading facilities experiences the greatest increase in the cost of production – in 2050, the cost of producing a barrel of synthetic crude from oil sands is $5.72 greater than in the reference case. The cost increase of producing blended bitumen is lower largely because blended bitumen is upgraded outside the sector.

Table 78: Increase in the cost of petroleum crude production by sub-sector

	Increase in Costs (2005$ / barrel)			
	2020	*2030*	*2040*	*2050*
All Production	$1.88	$2.69	$3.12	$3.23
Conventional	$1.18	$1.73	$1.83	$1.93
Synthetic	$3.28	$4.65	$5.48	$5.72
Blended bitumen	$0.69	$1.25	$1.65	$1.90

Table 79 shows how capital, operating and fuel costs contribute to the rise in cost of producing a barrel of oil. Energy costs increase significantly for two main reasons. First, the sector becomes more energy intensive per barrel of oil produced, largely due to the energy penalty associated with carbon capture and storage. Second, the policy encourages fuel switching away from petroleum products (e.g., petroleum coke and heavy fuel oil) to natural gas and electricity, which are forecasted to have higher prices per unit of energy produced. Capital costs also increase significantly, mostly due to the adoption of carbon capture and storage.

Table 79: Increase in the cost of petroleum crude production[37]

	Increase in Costs (2005$ / barrel)			
	2020	*2030*	*2040*	*2050*
Total Cost	$1.88	$2.69	$3.12	$3.23
Capital Costs	$0.87	$1.09	$1.14	$1.10
Operating & Maintenance Costs	$0.23	$0.33	$0.40	$0.40
Energy Costs	$0.77	$1.26	$1.58	$1.72

Provincial discussion

The production of crude oil is forecasted to be highly concentrated within Alberta as the production of conventional crude declines and the production of synthetic crude and blended bitumen from Alberta's oil sands increases. By 2050, Alberta is expected to produce approximately 6.7 million barrels per day, which will account for approximately 95% of Canada's crude oil production. Therefore, the results shown above are mostly indicative of petroleum sector in Alberta. The remaining oil-producing provinces are expected to produce conventional crude.[38]

[37] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

[38] The potential development of oil sands in Saskatchewan has not been considered in this analysis. However, this development is a strong possibility (National Energy Board, 2007, "Canada's Energy

Figure 46 shows the greenhouse gas intensity of conventional crude production outside Alberta. The increase in greenhouse gas intensity in the reference case is due to the relative decline of light and medium production (which is less greenhouse gas intensive) in comparison to the production of heavy crude. The policy encourages the adoption of technologies that limit the fugitive emissions (mostly venting and flaring) from conventional oil production. As a result, the greenhouse gas intensity of oil production declines by approximately 80% from the business-as-usual projection.

Figure 46: Greenhouse gas intensity of conventional petroleum crude production outside Alberta

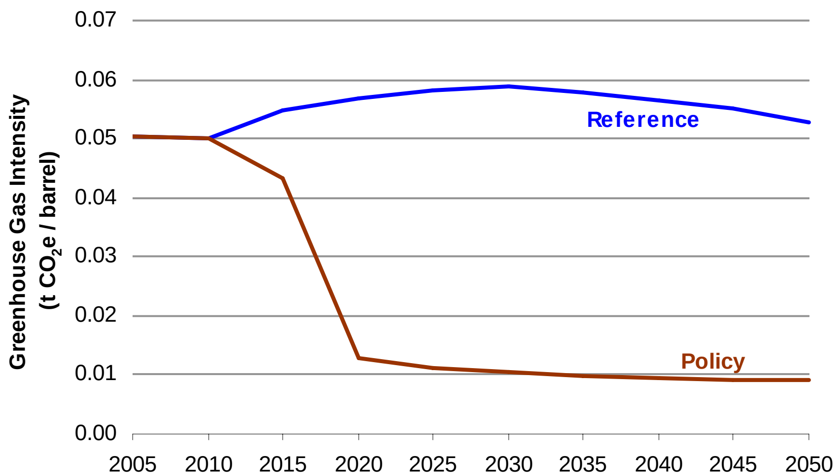


Table 80 shows the cost of oil production outside Alberta. The adoption of abatement technologies increases the cost of producing a barrel of oil by $1.55 ($2005) or approximately 7% in 2050. The increase in cost of production is lower outside Alberta because all production is forecasted to be conventional.

Table 80: Increase in the cost of petroleum crude production outside Alberta

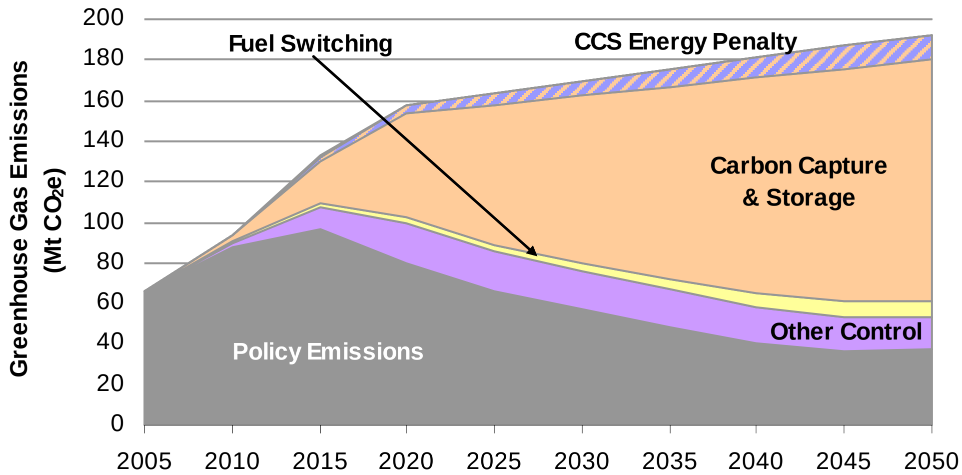
	Increase in Costs (2005$ / barrel)			
	2020	*2030*	*2040*	*2050*
All Production	$0.87	$1.33	$1.46	$1.55

Technology roadmap to low emissions for petroleum crude production

Carbon capture and storage accounts for approximately 85% of the reduction in greenhouse gas emissions in 2050, while other controls (e.g., reduced venting and flaring) and fuel switching to low carbon fuels account for approximately 10% and 5% of emissions reductions, respectively (see Figure 47).

Future"). The remaining provinces are not currently known to have any unconventional sources of petroleum that could be developed.

Figure 47: Wedge diagram for petroleum crude production



The oil sands sector employs three processes which are suitable for carbon capture and storage: 1) the production of hydrogen in oil sands upgrading; 2) the production of process heat for oil sands upgrading; and 3) the production of steam for in-situ operations. Hydrogen production via steam methane reforming or coke gasification can be designed or retrofitted to produce a relatively pure stream of carbon dioxide, which avoids the costly process of separating the carbon dioxide from other flue gases. Estimates of the costs of carbon capture from hydrogen production range from $5-50 / tonne CO_2e. Therefore, hydrogen production represents an opportunity for the early adoption for carbon capture.[39]

The emissions generated during the production of process heat for oil sands upgrading and from bitumen extraction at in-situ operations can also be captured. The cost of carbon capture from these sources is likely to be similar to the costs of capture from the electricity generation sector – between $15 and $75 ($US) per tonne of CO_2e avoided.[40]

Table 81 shows the penetration of carbon capture and storage in the oil sands sector in the policy scenario as a percentage of total installed stock. Hydrogen production shows the fastest penetration of carbon capture and storage, while penetration is slightly slower for the production of process heat for upgrading and steam production in in-situ extraction. By 2050, all hydrogen production and oil sands upgrading employs carbon capture and storage. Steam and heat production in in-situ operations predominately adopt carbon capture and storage, however a small portion of steam is produced from low emissions sources of energy (e.g., electricity). In-situ operations could also use nuclear energy to produce heat and steam if it becomes politically acceptable to do so. As discussed above, the option of nuclear power in this sector has been excluded from this analysis.

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[39] Intergovernmental Panel on Climate Change, 2005, "Carbon Dioxide Capture and Storage"; Keith D., 2002, "Toward a Strategy for Implementing CO_2 Capture and Storage in Canada".

[40] Intergovernmental Panel on Climate Change, 2005, "Carbon Dioxide Capture and Storage".

Table 81: Penetration of carbon capture and storage in oil sands sector

	2020	*2030*	*2040*	*2050*
Hydrogen Production	91%	98%	100%	100%
Oil Sands Upgrading	58%	88%	96%	99%
In-situ	35%	54%	57%	55%

In addition to carbon capture and storage, significant emissions reductions result from fuel switching and from actions that reduce fugitive emissions, such as reducing venting and flaring from conventional oil wells. The sector switches from petroleum products (e.g., petroleum coke and heavy fuel oil) to natural gas and electricity as a result of the policy, primarily for steam and heat production.

Our analysis includes several in-situ extraction technologies with the potential to greatly reduce the steam requirement of extraction. These include solvent-based systems to reduce the viscosity of the bitumen (e.g., VAPEX) and underground combustion processes (e.g., Toe to Heel) that liquefy and push the bitumen to the surface. We expect these technologies to be adopted regardless of the policy because they reduce energy costs, but the policy is likely to accelerate their adoption. Overall, these technologies are projected to improve the energy efficiency of the sector over time, but not significantly in response to the policy.

The capital expenditures required to attain the emissions reductions in the petroleum extraction sector are 23% greater in the medium-term, and 17% greater in the long-term than in the reference scenario (Table 82). The rise in capital expenditures is greater in the medium-term due to the retrofitting of existing oil sands upgraders with carbon capture equipment. In the long-term, most investments in carbon capture are made in new facilities.

Table 82: Increase in capital expenditures of petroleum crude production

	Medium-Term (2011-2030)	*Long-term (2031-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	1,236	768
Increase in Capital Expenditures (% above the reference case)	23%	17%

Uncertainty in the analysis

The petroleum crude sector may have the option to use nuclear energy to produce the heat and steam required for oil sands upgrading and bitumen extraction in in-situ operations. We have excluded this option from the analysis because the decision is more political than economic. The adoption of nuclear energy to power oil sands production would significantly reduce the role of carbon capture and storage in heat production. Nuclear power could also be used to produce hydrogen by electrolysis.

The impact of the policy on the output from the sector is also significantly uncertain. In this analysis, we assume that the Canadian production of petroleum will not change when the policy is implemented. We assume that the selling price of petroleum (i.e., the global price for oil) will exceed the cost of producing it in Canada regardless of the policy – in other words, the sector generates economic profits or rents. This assumption is likely imperfect, but the US Energy Information Administration projects that international demand for crude oil and natural gas is likely to remain robust even with the introduction of climate change abatement policies.[41] However, if the price for oil declines significantly, the policy may reduce production from high cost sources of petroleum.

Natural gas extraction, transmission and distribution

Box 14: Key actions by the natural gas extraction sector

- Most emissions reductions are attained from carbon capture and storage.
- The separation of formation carbon dioxide from raw natural gas is likely to be an early opportunity to adopt carbon capture. The process produces a relatively pure stream of carbon dioxide, which can be captured at low cost – approximately \$20/tonne CO_2e.

The natural gas extraction and processing sector is projected to play a declining role in Canada's greenhouse gas emissions, as the output from conventional natural gas fields declines. The development of coal bed methane partially offsets the decline from conventional fields, but total output is projected to decrease from 174 billion m^3 in 2005 to 140 billion m^3 in 2050. In the reference case, greenhouse gas emissions also decline from 65 Mt CO_2e in 2005 to 37 Mt CO_2e in 2050, reflecting the reduction in output. Approximately half of the greenhouse gas emissions are from combustion sources – engines and the production of process heat at natural gas processing plants – while half are process emissions. Process emissions from natural gas extraction include formation carbon dioxide, fugitive emissions from natural gas wells and leaks from pipelines. Formation carbon dioxide is extracted from the well with the raw natural gas and is removed and vented before it is marketed.

Environmental impact of policy

The energy and greenhouse gas intensity of the industry decline in the reference case, mostly as a result of improvements in the energy efficiency of natural gas extraction and processing (see Figure 48 and Figure 49). These improvements offset the transition towards extracting natural gas from coal beds, which is more energy and greenhouse gas intensive. Greenhouse gas intensity further declines from a modest adoption of leak detection and repair programs, which increase costs but also reduce losses of natural gas.

In the policy scenario, both the energy and greenhouse gas intensity of the sector decline. These improvements in energy efficiency offset the energy efficiency penalty associated with carbon capture and storage. The greenhouse gas intensity of natural gas production drops as a result of the capture of formation carbon dioxide and combustion emissions from processing plants, as well as from leak detection and repair programs.

[41] Energy Information Administration, 1998, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity", United States Department of Energy.

Figure 48: Energy intensity of natural gas extraction, transmission and distribution

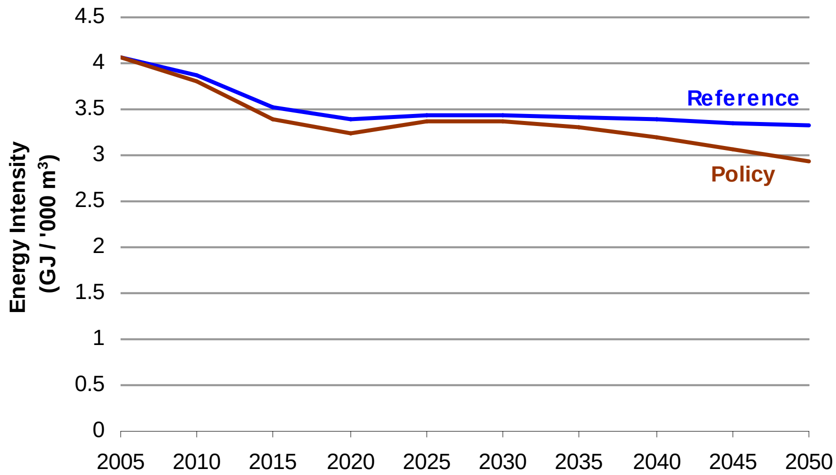
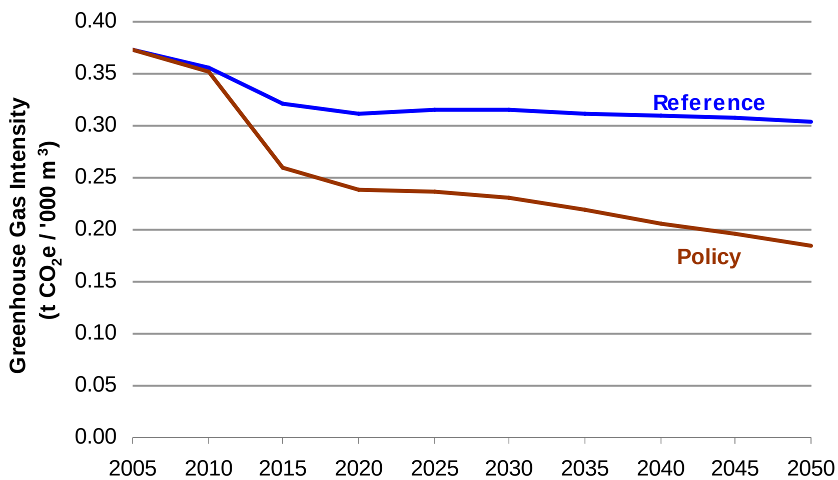


Figure 49: Greenhouse gas intensity of natural gas extraction, transmission and distribution



The share of electricity increases in response to the policy, while the share of natural gas declines (see Table 83). The increase in electricity consumption is mostly due to a greater use of electric motors to drive pipelines and operate natural gas wells.

Table 83: Fuel switching in natural gas extraction, transmission and distribution

	2020	*2030*	*2040*	*2050*
Natural Gas	-4%	-6%	-11%	-19%
Refined Petroleum Products	0%	0%	1%	1%
Electricity	3%	6%	11%	18%

Economic impact of policy

Table 84 shows the rise in the costs of extracting and transporting natural gas that results from the policy. Overall, the change in the cost of producing, transmitting and distributing natural gas is negligible – less than a percent. Capital expenditures show the only increase is due to the adoption of carbon capture and leak detection programs.

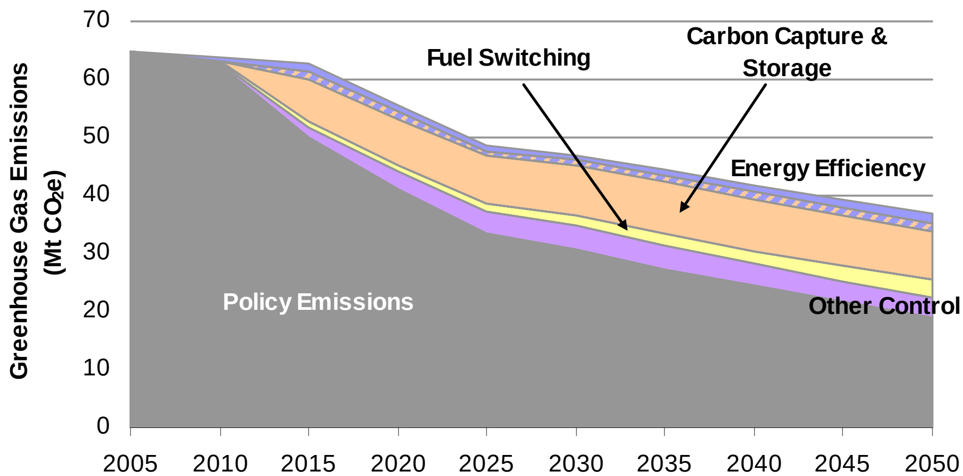
Table 84: Cost of natural gas extraction, transmission and distribution[42]

	Increase in Costs (2005$ / GJ)			
	2020	*2030*	*2040*	*2050*
Total Cost	-$0.02	-$0.04	-$0.04	-$0.03
Capital Costs	$0.01	$0.02	$0.04	$0.06
Operating & Maintenance Costs	-$0.02	-$0.04	-$0.05	-$0.06
Energy Costs	-$0.01	-$0.02	-$0.02	-$0.02

Technology roadmap to low emissions in natural gas extraction, transmission and distribution

Carbon capture and storage accounts for approximately 45% of the emissions reductions, while leak detection and repair programs and fuel switching each account for about 20% (Figure 50).

Figure 50: Wedge diagram for natural gas extraction, transmission and distribution



Capturing formation carbon dioxide is likely to be an early opportunity for implementing carbon capture and storage. In response to regulations on flaring acid gas (H_2S), one option for disposing this gas in small plants is to store the entire acid gas stream (including the formation carbon dioxide) in a geological formation. Carbon capture and storage from these sources would have little to zero additional cost. For larger plants, which are more likely to recover the sulphur instead of store the entire acid gas stream, carbon capture is still a relatively cheap option because the technology can be designed or retrofitted to produce a relatively pure stream of carbon dioxide. The cost of capturing formation carbon dioxide is estimated at approximately $20/tonne CO_2e.[43] Carbon capture from combustion sources is likely to have similar costs to combustion sources in

[42] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

[43] Keith, 2002, "Toward a Strategy for Implementing CO_2 Capture and Storage in Canada".

other sectors – around \$50/tonne CO_2e. Table 85 shows the penetration of carbon capture for formation carbon dioxide and the combustion sources in natural gas processing plants.

Table 85: Penetration of carbon capture in natural gas extraction

	2020	2030	2040	2050
Formation Carbon Dioxide	100%	100%	100%	100%
Combustion Emissions in Processing Plants	32%	63%	98%	100%

In addition to carbon capture, the sector reduces fugitive emissions through leak detection and repair programs. These programs identify and fix leaks at natural gas wells and pipelines. Table 86 shows fugitive emissions per unit of natural gas production. Fugitive emissions decline regardless of the policy because the reduction of fugitive methane increases natural gas production. However fugitive emissions decline by 28% from the reference case projection in the policy scenario.

Table 86: Fugitive emission rate from natural gas wells and pipelines

	Fugitive Emissions (tonne CO_2e / '000 m^3)			
	2020	2030	2040	2050
Reference Case	0.098	0.094	0.091	0.089
Policy	0.081	0.070	0.067	0.064
Reduction due to Policy (%)	17%	25%	27%	28%

The motors that drive pipelines and operate wells may use electricity instead of natural gas. Table 87 shows the penetration of electric motors for operating wells and pipelines. By 2050, close to 80% of all motors use electricity, a 60% increase from the reference projection.

Table 87: Penetration of electric motors for operating wells and pipelines

	Penetration of Electric motors (%)			
	2020	2030	2040	2050
Reference Case	8%	12%	15%	18%
Policy	22%	33%	53%	77%
Increase due to Policy (%)	13%	22%	38%	59%

Table 88 shows that attaining deep reductions in greenhouse gas emissions requires around a 5% increase capital expenditures over the reference case. The increase in capital costs is mostly from the addition of carbon capture and storage and leak detection and repair equipment.

Table 88: Increase in capital expenditures of natural gas extraction, transmission and distribution

	Medium-Term (2011-2030)	Long-term (2031-2050)
Increase in Annual Capital Expenditures (2005\$ Millions)	88	127
Increase in Capital Expenditures (% above the reference case)	4%	6%

Biofuels manufacturing

Box 15: Key actions by the biofuels manufacturing sector

- The policy induces a significant increase in the production of biofuels. In the reference projection, the demand and production of biofuels is negligible, but increases to 2,095 PJ in 2050 in the policy scenario.

- In the policy scenario, the sector reduces its greenhouse gas intensity by adopting carbon capture and storage and producing ethanol from cellulose instead of corn.

The production of biofuels (liquid transport fuels derived from biomass) is expected to remain relatively minor in the reference scenario, reaching just 103 PJ in 2050. However, substituting conventional fossil fuels with biofuels has the potential to reduce greenhouse gas emissions from the transportation sector, and other sectors such as petroleum extraction and mining. Production of biofuels increases dramatically in the policy scenario, reaching 2,095 PJ in 2050. Switching to biofuels reduces greenhouse gas emissions by 175 Mt CO_2e in 2050, accounting for 16% of total emissions reductions for Canada.

Several types of biofuels exist, with multiple methods of producing them. The two dominant forms of biofuels today are ethanol and esters, the latter more commonly known as biodiesel. Ethanol is usually produced from sugar or starchy crops, and in Canada is primarily distilled from corn and wheat, while biodiesel is produced mainly from oil-seed crops such as rapeseed, palm and sunflowers.[44] Ethanol can be used in most automotive engines when blended in low concentrations with gasoline, but requires modifications to the vehicle engine to be used in high or pure blends. However, biodiesel can be used easily in most compression-ignition engines in its pure form or blended with conventional diesel fuel.[45] Some types of biodiesel freeze at lower temperatures than others, although fuel additives and engine block or fuel filter heaters can remedy this problem.[46]

The production of agricultural crops and the conversion of these crops into biofuels, especially corn-based ethanol, can be energy intensive; however advanced methods of producing biofuels (such as enzymatic hydrolysis and gasification of woody ligno-cellulosic feedstock) may reduce these requirements in the future. Note that the following discussion concerning biofuels manufacturing ignores inter-provincial differences because production processes are likely to be similar among regions.

Environmental impact of policy

Figure 51 and Figure 52 show the energy intensity of ethanol and biodiesel production in the reference and policy scenarios. The energy intensity of ethanol production decreases markedly in both the reference and policy scenarios, due to the adoption of cellulosic production techniques which are less energy intensive. In the policy scenario, the energy intensity of ethanol production reaches 0.07 GJ / GJ ethanol by 2050, 92% lower than in 2005 and 64% lower than the reference projection for 2050. The energy intensity of

[44] Natural Resources Canada, 2006, "Ethanol: The Road to a Greener Future," http://oee.nrcan.gc.ca/publications/infosource/pub/vehiclefuels/ethanol/M92_257_2003.cfm

[45] International Energy Agency, 2006, "World Energy Outlook," Paris: OECD/IEA.

[46] Natural Resources Canada, 2008, "Biodiesel: Safety & Performance," http://www.oee.nrcan.gc.ca/transportation/fuels/biodiesel/biodiesel-safety.cfm?attr=8

biodiesel production does not change significantly in the reference or policy scenario, remaining at about 0.20 GJ / GJ biodiesel.

Figure 51: Energy intensity of ethanol production

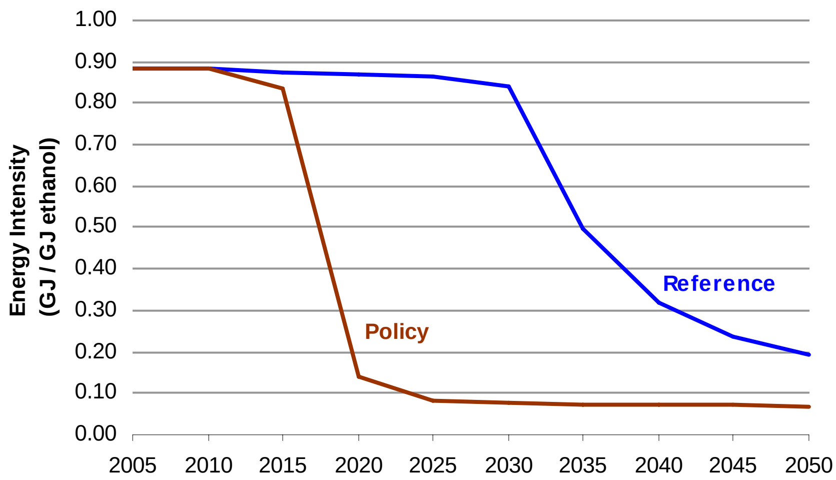


Figure 52: Energy intensity of biodiesel production

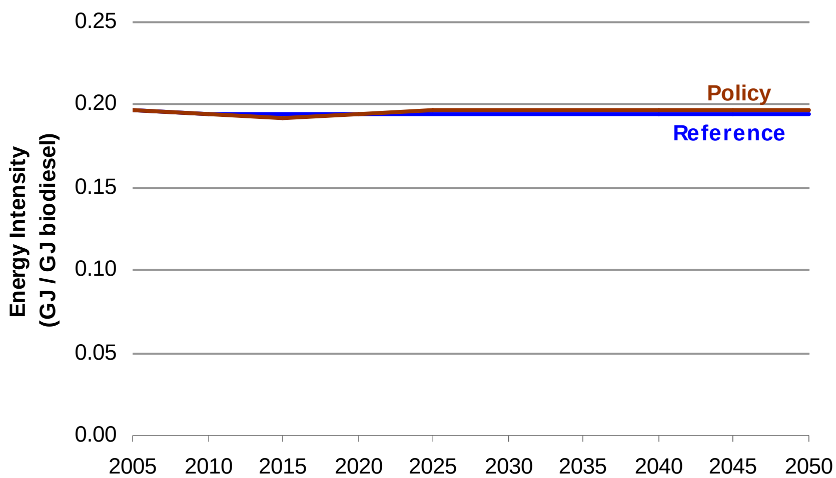


Figure 53 and Figure 54 show the greenhouse gas intensity of ethanol and biodiesel production in the reference and policy scenarios. The greenhouse gas intensity decreases substantially in both scenarios, but is accelerated in the policy scenario. In the policy scenario, the greenhouse gas intensity of ethanol production drops from 0.045 tonne CO_2e / GJ ethanol in 2005 to 0.002 tonne CO_2e / GJ ethanol in 2050, a decrease of 95%. The switch to cellulosic ethanol production plays a large role in reducing greenhouse gas emissions from ethanol production. The greenhouse gas intensity of biodiesel production also decreases substantially, from 0.015 t CO_2e / GJ biodiesel in 2005 to 0.004 t CO_2e / GJ biodiesel in 2050, a decrease of 73%. The decline in greenhouse gas intensity from biodiesel production is mostly from installing electric boilers and adopting carbon capture and storage.

Figure 53: Greenhouse gas intensity of ethanol production

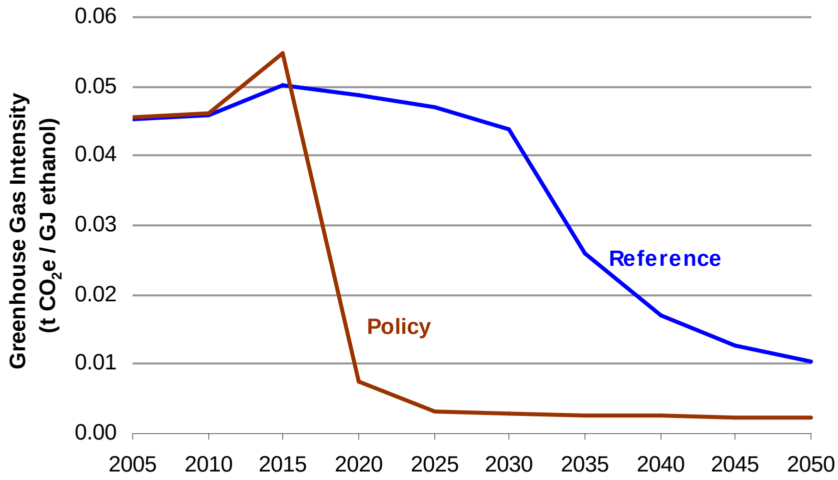


Figure 54: Greenhouse gas intensity of biodiesel production

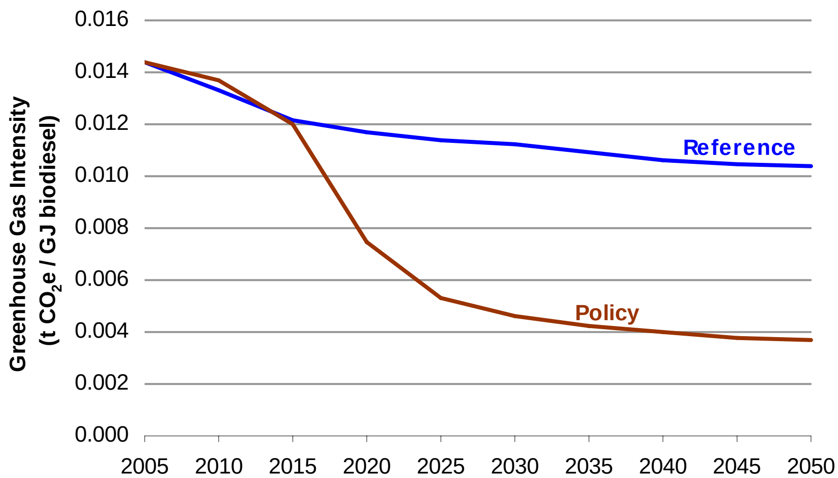


Table 89 shows the change in fuel shares that result from the policy scenario. Overall, the sector shifts from coal and natural gas towards electricity and renewable energy. The majority of the observed shifts in fuel consumption occur from the energy used to produce process heat, although a shift to biodiesel for fuel in agricultural machinery also contributes to the increase in renewable energy.

Table 89: Fuel switching in biofuels manufacturing

	2020	*2030*	*2040*	*2050*
Natural Gas	-14%	-18%	-15%	-11%
Coal	-9%	-14%	-12%	-12%
Refined Petroleum Products	3%	10%	3%	-1%
Electricity	16%	15%	14%	15%
Renewable	4%	8%	9%	9%

Economic impact of policy

Table 90 and Table 91 show the increase in production costs relative to the reference case for ethanol and biodiesel, respectively. The production costs for ethanol decrease because the policy scenario results in a more rapid and widespread adoption of cellulosic ethanol, which requires up to 90% less energy. The capital requirements of producing a unit of ethanol also decline, as manufacturers accumulate experience more rapidly with cellulosic ethanol. In 2050, ethanol production costs are 6% lower than in the reference case in 2050, and 36% lower than in 2005. On the other hand, production costs for biodiesel increase modestly, and in 2050 are 3% higher than in the reference case. This increase is due to the higher energy costs of electricity and renewable energy relative to conventional fossil fuels in the policy scenario.

Table 90: Increase in the cost of ethanol production[47]

	Increase in Costs (2005$ / GJ Ethanol)			
	2020	*2030*	*2040*	*2050*
Total Cost	-$4.11	-$7.01	-$2.15	-$1.03
Capital Costs	$2.03	-$0.50	-$0.10	-$0.04
Operating & Maintenance Costs	-$0.17	-$0.18	-$0.06	-$0.03
Energy Costs	-$5.98	-$6.33	-$1.99	-$0.96

Table 91: Increase in the cost of biodiesel production

	Increase in Costs (2005$ / GJ Biodiesel)			
	2020	*2030*	*2040*	*2050*
Total Cost	$0.42	$0.64	$0.61	$0.60
Capital Costs	$0.06	$0.10	$0.12	$0.11
Operating & Maintenance Costs	$0.00	-$0.01	$0.00	$0.00
Energy Costs	$0.36	$0.55	$0.49	$0.49

Technology roadmap to low emissions in biofuels manufacturing

The increase in biofuels production in the policy scenario results in an increase in energy consumption and greenhouse gas emissions. Most of the declines in emissions intensity are the result of improved energy efficiency and carbon capture and storage. Table 92 shows the emissions reductions by action in biofuels manufacturing.

Table 92: Emissions reductions by action in biofuels manufacturing (Mt CO_2e)

	2020	*2030*	*2040*	*2050*
Output	-1.95	-5.98	-8.06	-8.75
Fuel Switching	0.13	0.35	0.44	0.45
CCS	0.08	0.44	0.64	0.81
CCS Energy Efficiency Penalty	0.01	0.06	0.08	0.10
Energy Efficiency	0.28	1.36	0.98	0.72
Total Reductions	-1.44	-3.77	-5.93	-6.68

Switching to cellulosic ethanol production methods substantially reduces the energy intensity of producing biofuels. Conventional ethanol production from corn currently accounts for all ethanol production, but the development of cellulosic ethanol technology

[47] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

is accelerated in the policy scenario, and accounts for all production by 2030 (see Table 93).

Table 93: Penetration of cellulosic ethanol

	2020	2030	2040	2050
Reference	0%	3%	68%	84%
Policy	91%	99%	100%	100%
Increase due to Policy	91%	96%	32%	16%

The policy scenario results in a large switch away from conventional fossil fuel-fired heat production towards electricity and carbon capture and storage. Table 94 shows the penetration of these technologies in the biofuels sector. By 2050, electricity and carbon capture and storage account for virtually all heat production.

Table 94: Penetration of electricity and carbon capture and storage in heat production

	2020	2030	2040	2050
Electric	25%	44%	49%	52%
Carbon Capture and Storage	37%	45%	46%	46%

Table 95 shows the increase in capital expenditures in the policy scenario. Capital expenditures must rise dramatically to meet the rapid growth in demand in the policy scenario.

Table 95: Increase in capital expenditures that results from policy

	Medium-Term (2011-2025)	Long-term (2026-2050)
Increase in Annual Capital Expenditures (2005$ Millions)	1,519	2,637
Increase in Capital Expenditures (% above the reference case)	3,336%	1,819%

Uncertainty in the analysis

Several sources of uncertainty are present in this analysis. First, as agricultural land is devoted to the production of biofuel crops, the costs of these crops should increase as less additional land is available for production. However, the possibility for alternative inputs (such as a variety of fibres for cellulosic ethanol) and higher agricultural yields may diminish these price feedbacks.[48] This analysis assumes that the cost of agricultural inputs does not vary according to production of biofuels.

Second, a variety of other factors could impact the potential for biofuels to reduce greenhouse gas emissions in Canada. For example, concerns about food costs and land availability could minimize the desired role for biofuels; alternatively, additional support could be given to biofuels in order to increase revenue for agricultural producers.

Landfills

Box 16: Key actions by the landfill sector

- Capturing and flaring landfill gas, which has high concentrations of methane, may

[48] International Energy Agency, 2006, “World Energy Outlook,” Paris: OECD/IEA.

be an early opportunity for abating greenhouse gas emissions in Canada. By 2020, the policy induces almost all landfills in Canada to control landfill gas emissions.

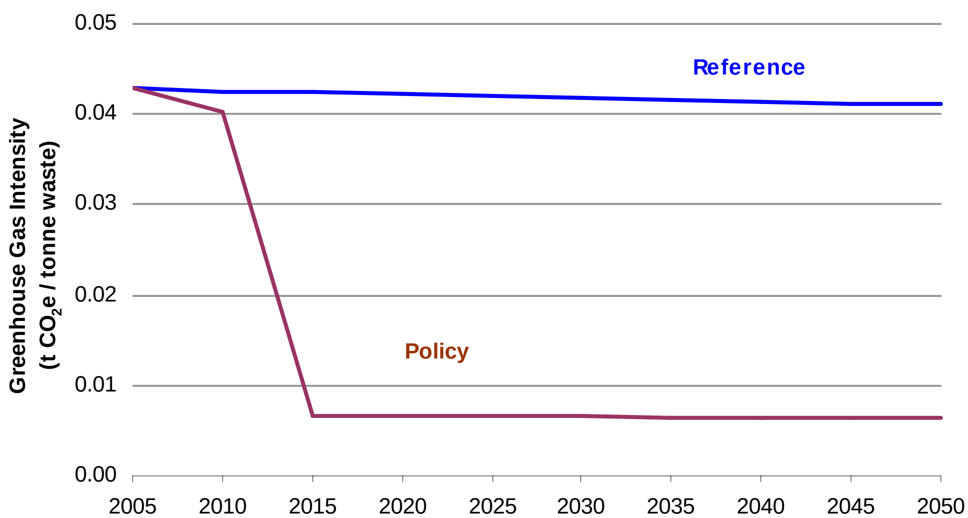
Canadian landfills emitted approximately 27.5 Mt CO_2e in 2005, and in the reference scenario are expected to emit 33.9 Mt by 2050.[49] The decomposition of organic waste in these landfills produces methane and carbon dioxide, which are generally released into the atmosphere. Some landfills capture and flare landfill gas to control odours or to generate electricity from methane, although the capture of landfill gas is unlikely to expand substantially without a policy intervention.

In 2005, about 29% of landfill waste was subjected to gas flaring across Canada, and less than 1% of waste was used for electricity generation. The remaining 70% of landfill waste was not subject to any control measures. Although the current status of flaring varies among provinces, the following discussion ignores regional differences because the potential for mitigation actions is judged to be largely similar among regions.

Environmental impact of policy

Landfills may present an early opportunity for reducing greenhouse gas emissions. In the reference scenario, the greenhouse gas intensity of landfills remains stable (see Figure 55). In the policy scenario, greenhouse gas intensity drops dramatically to 0.007 tonnes CO_2e per tonne of waste in 2015, a decrease of 84%.

Figure 55: Greenhouse gas intensity of landfills



[49] Note that Environment Canada has recently revised this estimate downward to 21 Mt CO_2e in 2005 (Environment Canada, 2008, "National Inventory Report"). This revision has not been included in the analysis.

Economic impact of policy

The costs of capturing landfill gas are presented in Table 96. Capital costs and operating and maintenance costs increase relative to the reference scenario, but are offset in large part by revenue from electricity generation. In 2050, total costs are $5.71 per tonne of waste higher than in the reference scenario.

Table 96: Increase in the cost of landfill waste processing[50]

	Increase in Costs (2005$ / tonne waste)			
	2020	*2030*	*2040*	*2050*
Total Cost	$5.49	$5.39	$5.56	$5.71
Capital Costs	$5.57	$5.51	$5.70	$5.86
Operating & Maintenance Costs	$0.15	$0.17	$0.18	$0.19
Energy Costs	-$0.23	-$0.29	-$0.32	-$0.33

Technology roadmap to low emissions in landfills

The wedge diagram in Figure 56 illustrates the rapid reduction of emissions from Canada's landfills. By 2015, greenhouse gas emissions are only 4.6 Mt CO_2e – 84% below the reference scenario. The reduction in emissions is possible because of a rapid uptake of flaring and electricity generation among landfills. In the reference scenario, 70% of landfill waste is not subjected to any greenhouse gas control. In the policy scenario, all landfill waste is subjected to control measures by 2015 (see Table 97). After 2015, the proportion of waste used to generate electricity gradually increases, reaching 62% in 2050. By 2050, the sector generates 5.4 TWh of electricity.

Figure 56: Wedge diagram for landfills

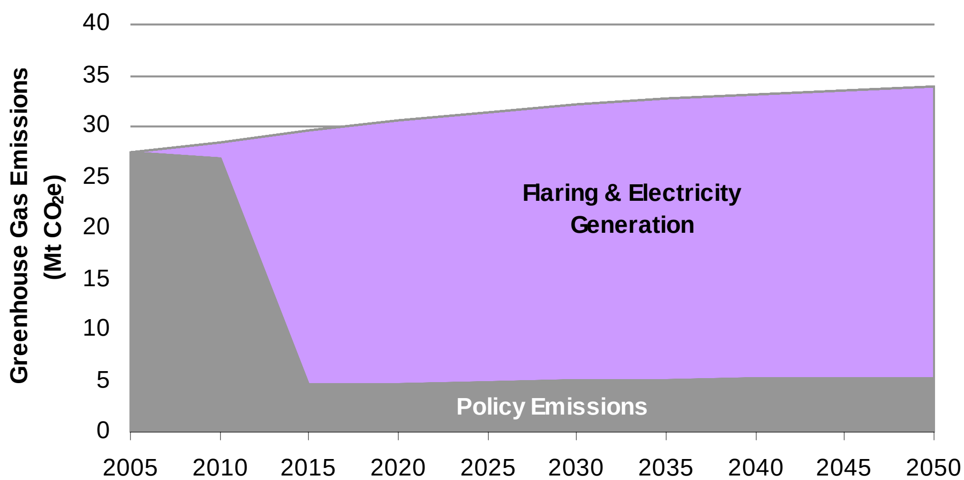


Table 97: Proportion of landfill waste subjected to greenhouse gas control measures

	2020	*2030*	*2040*	*2050*
No Control	0%	0%	0%	0%
Flaring	61%	50%	43%	38%
Electricity Generation	39%	50%	57%	62%

[50] The table does not show emissions costs, because all emissions costs are recycled back to the sector.

Table 98 shows the increase in capital expenditures from the policy scenario. Capital expenditures must rise to cap landfills and install the flaring equipment, especially in the medium term.

Table 98: Increase in capital expenditures of landfills

	Medium-Term (2011-2025)	*Long-term (2026-2050)*
Increase in Annual Capital Expenditures (2005$ Millions)	70	19
Increase in Capital Expenditures (% above the reference case)	1,656%	570%

Uncertainty in the analysis

This analysis assumes that all landfills are capable of capturing and flaring landfill gas. The cost of capturing and flaring landfill gas varies depending on the size of the landfill, and whether the landfill gas could be used to generate electricity. However, most landfills in Canada should capture and flare their emissions once the price for emissions has exceeded \$80/tonne CO_2e.[51]

[51] Marbek, 2002, "Business Plan for GMIF Investments: Landfill Gas Sector".

Appendix A – Detailed Quantitative Results

Reference case – Canada

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	40	41	40	39
Commercial	41	47	56	66
Transportation	253	263	282	312
Manufacturing Industry	90	97	109	125
Landfills	31	32	33	34
Supply Sectors				
Electricity Generation	113	119	138	170
Petroleum Refining	24	26	29	32
Crude Oil	158	170	181	193
Natural Gas	56	47	42	37
Coal Mining	3	3	3	3
Biofuels Manufacturing	0	1	1	1
Total	807	845	915	1,012

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	1,567	1,760	1,977	2,303
Commercial	1,412	1,639	1,956	2,298
Transportation	3,522	3,728	4,077	4,557
Manufacturing Industry	2,527	2,770	3,105	3,497
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	4,127	4,626	5,448	6,560
Petroleum Refining	422	457	510	571
Crude Oil	1,996	2,202	2,342	2,506
Natural Gas	607	512	457	403
Coal Mining	24	25	26	27
Biofuels Manufacturing	4	13	16	20
Total	16,208	17,730	19,914	22,742

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	4,213	4,543	4,922	5,392
Coal	1,578	1,765	2,039	2,465
Refined Petroleum Products	3,993	4,106	4,482	4,982
Electricity	2,260	2,597	3,077	3,700
Nuclear	1,062	1,174	1,346	1,596
Biofuel	16	31	65	103
Renewable	2,312	2,666	3,062	3,524
Other	775	849	922	981
Total	16,208	17,730	19,914	22,742

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	103	106	115	129
Household Emissions Intensity (t CO_2e / household)	2.6	2.4	2.3	2.2
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.39	0.35	0.33	0.31
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.013	0.011	0.010	0.010
Annual Energy Costs (2005$ / household)	$1,807	$1,914	$2,150	$2,548
Electricity Price (2005¢ / kWh)	8.7	8.7	8.7	8.7
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.5	1.5	1.5	1.5
Emissions Intensity (t CO_2e / m^2 floorspace)	0.045	0.043	0.043	0.042
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.86	0.82	0.80	0.79
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.035	0.033	0.032	0.032
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.8	1.6	1.4	1.4
Passenger Emissions Intensity (kg CO_2e / pkt)	0.12	0.11	0.10	0.09
Passenger Vehicle Energy Intensity (MJ / vkt)	3.1	2.7	2.5	2.3
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.22	0.19	0.17	0.16
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,460	$1,394	$1,276	$1,208
Freight Energy Intensity (MJ / tkt)	1.2	1.1	1.1	1.1
Freight Emissions Intensity (kg CO_2e / tkt)	0.08	0.08	0.08	0.08
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	82.9	90.6	90.8	90.8
Electricity Generation				
Energy Intensity (GJ / MWh)	5.9	5.8	5.8	5.8
Emissions Intensity (t CO_2e / MWh)	0.16	0.15	0.15	0.15
Renewable Generation (TWh)	450	515	603	709
Nuclear Generation (TWh)	98	109	125	148
Coal Generation (TWh)	107	123	149	193
Natural Gas Generation (TWh)	37	44	50	56
CCS Generation (TWh)	4	10	19	27
Other Generation (TWh)	5	1	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	1.1	1.1	1.0	1.0
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.09	0.08	0.08	0.08
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – British Columbia

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	3	3	3	3
Commercial	4	5	5	7
Transportation	39	40	44	49
Manufacturing Industry	9	10	12	13
Landfills	6	6	7	7
Supply Sectors				
Electricity Generation	1	2	2	3
Petroleum Refining	2	2	2	3
Crude Oil	0	0	0	0
Natural Gas	13	12	12	11
Coal Mining	2	2	2	2
Biofuels Manufacturing	0	0	0	0
Total	79	82	89	97

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	153	192	224	270
Commercial	165	193	234	280
Transportation	537	571	634	716
Manufacturing Industry	454	503	562	624
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	340	449	566	703
Petroleum Refining	26	30	37	45
Crude Oil	3	2	2	2
Natural Gas	118	113	105	97
Coal Mining	14	14	14	14
Biofuels Manufacturing	1	3	3	4
Total	1,809	2,071	2,381	2,755

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	345	376	424	481
Coal	18	21	22	24
Refined Petroleum Products	579	606	661	736
Electricity	283	356	433	526
Nuclear	0	0	0	0
Biofuel	6	8	13	18
Renewable	564	686	807	943
Other	15	18	23	28
Total	1,809	2,071	2,381	2,755

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	76	79	87	101
Household Emissions Intensity (t CO_2e / household)	1.6	1.3	1.2	1.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.24	0.21	0.20	0.19
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.007	0.004	0.003	0.003
Annual Energy Costs (2005$ / household)	$1,224	$1,302	$1,468	$1,731
Electricity Price (2005¢ / kWh)	6.5	6.5	6.5	6.5
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.2	1.2	1.1	1.1
Emissions Intensity (t CO_2e / m^2 floorspace)	0.029	0.027	0.027	0.027
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.65	0.62	0.61	0.60
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.024	0.022	0.022	0.022
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.8	1.6	1.5	1.4
Passenger Emissions Intensity (kg CO_2e / pkt)	0.12	0.11	0.10	0.09
Passenger Vehicle Energy Intensity (MJ / vkt)	3.1	2.7	2.5	2.3
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.22	0.19	0.16	0.15
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,523	$1,433	$1,290	$1,224
Freight Energy Intensity (MJ / tkt)	1.0	0.9	0.9	0.9
Freight Emissions Intensity (kg CO_2e / tkt)	0.07	0.07	0.07	0.07
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	86.0	93.2	92.7	92.6
Electricity Generation				
Energy Intensity (GJ / MWh)	4.0	4.2	4.3	4.4
Emissions Intensity (t CO_2e / MWh)	0.01	0.02	0.02	0.02
Renewable Generation (TWh)	82	101	122	148
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	3	5	6	8
CCS Generation (TWh)	0	1	2	3
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.2	0.2	0.2	0.2
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.04	0.03	0.03	0.03
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Alberta

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	8	8	9	9
Commercial	6	7	9	10
Transportation	40	42	45	51
Manufacturing Industry	15	16	18	20
Landfills	3	3	3	4
Supply Sectors				
Electricity Generation	55	55	57	63
Petroleum Refining	6	6	7	7
Crude Oil	147	162	175	188
Natural Gas	32	25	22	18
Coal Mining	1	1	1	1
Biofuels Manufacturing	0	0	0	0
Total	312	327	346	371

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	204	231	257	293
Commercial	193	223	264	304
Transportation	551	588	647	734
Manufacturing Industry	339	369	406	454
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	686	722	786	893
Petroleum Refining	103	113	124	136
Crude Oil	1,967	2,181	2,324	2,490
Natural Gas	346	276	238	201
Coal Mining	8	8	8	9
Biofuels Manufacturing	0	1	2	2
Total	4,398	4,713	5,055	5,517

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	1,895	2,000	2,062	2,196
Coal	864	907	954	1,036
Refined Petroleum Products	652	715	836	963
Electricity	262	294	336	396
Nuclear	0	0	0	0
Biofuel	2	3	6	10
Renewable	104	118	134	155
Other	619	676	728	761
Total	4,398	4,713	5,055	5,517

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	131	130	135	145
Household Emissions Intensity (t CO_2e / household)	5.1	4.8	4.5	4.2
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.59	0.53	0.49	0.46
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.028	0.025	0.024	0.022
Annual Energy Costs (2005$ / household)	$1,733	$1,815	$2,028	$2,415
Electricity Price (2005¢ / kWh)	9.5	9.5	9.5	9.5
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.6	1.6	1.6	1.5
Emissions Intensity (t CO_2e / m^2 floorspace)	0.053	0.053	0.053	0.052
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.99	0.96	0.96	0.94
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.044	0.043	0.043	0.043
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.8	1.7	1.6	1.5
Passenger Emissions Intensity (kg CO_2e / pkt)	0.13	0.12	0.11	0.10
Passenger Vehicle Energy Intensity (MJ / vkt)	3.3	3.0	2.7	2.6
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.24	0.21	0.19	0.18
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,494	$1,460	$1,347	$1,280
Freight Energy Intensity (MJ / tkt)	0.9	0.9	0.9	0.9
Freight Emissions Intensity (kg CO_2e / tkt)	0.07	0.06	0.06	0.07
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	78.9	87.0	87.4	87.6
Electricity Generation				
Energy Intensity (GJ / MWh)	8.9	8.3	7.9	7.6
Emissions Intensity (t CO_2e / MWh)	0.71	0.64	0.58	0.54
Renewable Generation (TWh)	8	10	14	17
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	54	58	62	72
Natural Gas Generation (TWh)	12	15	17	19
CCS Generation (TWh)	3	4	7	9
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	1.2	1.2	1.1	1.0
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.09	0.09	0.08	0.08
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Saskatchewan

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	1	1	1	1
Commercial	2	2	2	2
Transportation	11	11	11	11
Manufacturing Industry	2	3	4	5
Landfills	1	1	1	1
Supply Sectors				
Electricity Generation	16	17	19	22
Petroleum Refining	1	1	1	1
Crude Oil	10	7	6	5
Natural Gas	4	3	3	2
Coal Mining	0	0	0	0
Biofuels Manufacturing	0	0	0	0
Total	48	46	47	51

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	39	36	36	38
Commercial	52	56	64	74
Transportation	155	151	154	165
Manufacturing Industry	62	79	104	136
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	200	211	239	275
Petroleum Refining	16	16	16	18
Crude Oil	21	16	13	11
Natural Gas	34	27	24	21
Coal Mining	3	3	3	4
Biofuels Manufacturing	0	1	1	1
Total	581	596	654	742

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	171	170	188	212
Coal	157	175	200	236
Refined Petroleum Products	175	163	160	168
Electricity	56	64	77	92
Nuclear	0	0	0	0
Biofuel	0	1	3	5
Renewable	17	19	21	23
Other	4	5	5	5
Total	581	596	654	742

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	91	91	95	108
Household Emissions Intensity (t CO_2e / household)	3.0	2.6	2.3	2.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.43	0.38	0.33	0.32
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.019	0.015	0.013	0.012
Annual Energy Costs (2005$ / household)	$1,284	$1,343	$1,490	$1,771
Electricity Price (2005¢ / kWh)	7.3	7.3	7.3	7.3
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.7	1.6	1.6	1.6
Emissions Intensity (t CO_2e / m^2 floorspace)	0.059	0.055	0.053	0.053
Space Heating Energy Intensity (GJ / m^2 floorspace)	1.11	1.01	0.97	0.96
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.050	0.045	0.043	0.043
Transportation				
Passenger Energy Intensity (MJ / pkt)	2.1	1.8	1.7	1.6
Passenger Emissions Intensity (kg CO_2e / pkt)	0.15	0.12	0.11	0.10
Passenger Vehicle Energy Intensity (MJ / vkt)	3.3	2.8	2.6	2.4
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.23	0.20	0.17	0.16
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,576	$1,493	$1,356	$1,281
Freight Energy Intensity (MJ / tkt)	1.7	1.6	1.6	1.6
Freight Emissions Intensity (kg CO_2e / tkt)	0.12	0.11	0.11	0.11
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	84.6	92.5	92.4	92.4
Electricity Generation				
Energy Intensity (GJ / MWh)	9.4	8.9	8.6	8.5
Emissions Intensity (t CO_2e / MWh)	0.76	0.73	0.69	0.68
Renewable Generation (TWh)	5	5	6	6
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	13	16	18	23
Natural Gas Generation (TWh)	3	2	2	2
CCS Generation (TWh)	0	1	1	2
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.2	0.2	0.2	0.2
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.08	0.08	0.08	0.07
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Manitoba

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	1	1	1	1
Commercial	1	1	1	2
Transportation	7	7	6	7
Manufacturing Industry	1	1	1	1
Landfills	1	1	1	1
Supply Sectors				
Electricity Generation	0	0	0	0
Petroleum Refining	NA	NA	NA	NA
Crude Oil	0	0	0	0
Natural Gas	1	0	0	0
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	0	0	0
Total	12	11	11	11

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	47	52	60	74
Commercial	62	69	81	94
Transportation	99	95	96	102
Manufacturing Industry	39	42	47	52
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	170	195	225	261
Petroleum Refining	NA	NA	NA	NA
Crude Oil	2	1	1	1
Natural Gas	9	7	6	5
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	1	1	1
Total	427	462	517	592

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	61	56	59	64
Coal	5	2	2	2
Refined Petroleum Products	102	96	93	98
Electricity	93	116	141	170
Nuclear	0	0	0	0
Biofuel	0	1	3	4
Renewable	166	192	219	252
Other	0	0	0	0
Total	427	462	517	592

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	94	101	116	143
Household Emissions Intensity (t CO_2e / household)	1.6	1.2	1.1	1.0
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.34	0.30	0.27	0.26
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.008	0.005	0.004	0.003
Annual Energy Costs (2005$ / household)	$1,230	$1,333	$1,546	$1,909
Electricity Price (2005¢ / kWh)	4.9	4.9	4.9	4.9
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.5	1.4	1.4	1.4
Emissions Intensity (t CO_2e / m^2 floorspace)	0.033	0.027	0.025	0.024
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.74	0.66	0.62	0.61
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.021	0.015	0.013	0.012
Transportation				
Passenger Energy Intensity (MJ / pkt)	2.1	1.8	1.7	1.6
Passenger Emissions Intensity (kg CO_2e / pkt)	0.15	0.12	0.11	0.10
Passenger Vehicle Energy Intensity (MJ / vkt)	3.5	3.0	2.7	2.5
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.25	0.20	0.17	0.15
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,600	$1,480	$1,322	$1,228
Freight Energy Intensity (MJ / tkt)	1.2	1.1	1.1	1.1
Freight Emissions Intensity (kg CO_2e / tkt)	0.08	0.08	0.08	0.08
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	80.8	87.7	86.6	85.9
Electricity Generation				
Energy Intensity (GJ / MWh)	3.7	3.7	3.7	3.7
Emissions Intensity (t CO_2e / MWh)	0.01	0.00	0.00	0.00
Renewable Generation (TWh)	46	53	61	70
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	0	0	0	0
CCS Generation (TWh)	0	0	1	1
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.3	0.3	0.3	0.3
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.04	0.04	0.04	0.04
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Ontario

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	22	23	23	23
Commercial	20	24	30	35
Transportation	86	92	102	116
Manufacturing Industry	41	47	55	64
Landfills	8	9	10	11
Supply Sectors				
Electricity Generation	26	34	48	68
Petroleum Refining	8	9	10	12
Crude Oil	0	0	0	0
Natural Gas	4	4	3	3
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	0	0	0
Total	214	242	282	332

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	663	747	849	998
Commercial	585	706	864	1,025
Transportation	1,200	1,309	1,471	1,679
Manufacturing Industry	806	905	1,047	1,211
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	1,434	1,675	2,094	2,674
Petroleum Refining	130	150	177	208
Crude Oil	0	0	0	0
Natural Gas	58	52	51	48
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	1	3	4	5
Total	4,878	5,547	6,558	7,848

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	1,299	1,454	1,670	1,884
Coal	400	538	733	1,009
Refined Petroleum Products	1,326	1,425	1,590	1,805
Electricity	595	706	886	1,128
Nuclear	943	1,046	1,218	1,462
Biofuel	2	6	15	26
Renewable	258	304	365	437
Other	56	68	81	96
Total	4,878	5,547	6,558	7,848

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	111	113	119	131
Household Emissions Intensity (t CO_2e / household)	3.6	3.4	3.2	3.0
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.35	0.31	0.29	0.27
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.015	0.013	0.012	0.012
Annual Energy Costs (2005$ / household)	$1,882	$1,985	$2,220	$2,621
Electricity Price (2005¢ / kWh)	9.9	9.9	9.9	9.9
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.6	1.6	1.6	1.6
Emissions Intensity (t CO_2e / m^2 floorspace)	0.055	0.055	0.056	0.055
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.94	0.92	0.92	0.91
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.042	0.042	0.042	0.042
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.6	1.4	1.3	1.2
Passenger Emissions Intensity (kg CO_2e / pkt)	0.11	0.10	0.09	0.08
Passenger Vehicle Energy Intensity (MJ / vkt)	3.0	2.6	2.4	2.3
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.22	0.18	0.17	0.16
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,383	$1,329	$1,226	$1,160
Freight Energy Intensity (MJ / tkt)	1.5	1.4	1.4	1.4
Freight Emissions Intensity (kg CO_2e / tkt)	0.11	0.10	0.10	0.10
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	80.7	88.6	89.0	89.2
Electricity Generation				
Energy Intensity (GJ / MWh)	8.6	8.3	8.2	8.2
Emissions Intensity (t CO_2e / MWh)	0.15	0.17	0.19	0.21
Renewable Generation (TWh)	41	50	64	81
Nuclear Generation (TWh)	87	97	113	135
Coal Generation (TWh)	29	41	60	86
Natural Gas Generation (TWh)	9	10	12	14
CCS Generation (TWh)	1	3	6	9
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.3	0.2	0.2	0.2
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.04	0.03	0.03	0.03
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Québec

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	3	3	3	3
Commercial	5	4	4	5
Transportation	49	50	53	57
Manufacturing Industry	18	16	16	18
Landfills	8	9	9	9
Supply Sectors				
Electricity Generation	2	2	2	3
Petroleum Refining	5	5	5	5
Crude Oil	NA	NA	NA	NA
Natural Gas	0	0	0	0
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	0	0	0
Total	90	90	93	99

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	370	411	456	528
Commercial	269	292	333	386
Transportation	682	719	774	846
Manufacturing Industry	680	720	781	851
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	868	968	1,121	1,308
Petroleum Refining	82	85	91	98
Crude Oil	NA	NA	NA	NA
Natural Gas	6	6	6	6
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	1	3	4	6
Total	2,959	3,203	3,567	4,029

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	289	309	332	364
Coal	25	27	28	30
Refined Petroleum Products	756	754	796	857
Electricity	807	892	1,021	1,181
Nuclear	69	80	92	103
Biofuel	5	9	17	28
Renewable	961	1,084	1,230	1,410
Other	47	48	51	55
Total	2,959	3,203	3,567	4,029

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	100	107	118	137
Household Emissions Intensity (t CO_2e / household)	0.9	0.9	0.8	0.7
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.48	0.45	0.42	0.40
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.005	0.005	0.004	0.003
Annual Energy Costs (2005$ / household)	$2,066	$2,239	$2,529	$3,007
Electricity Price (2005¢ / kWh)	8.4	8.4	8.4	8.4
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.6	1.5	1.5	1.4
Emissions Intensity (t CO_2e / m^2 floorspace)	0.028	0.021	0.019	0.018
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.75	0.64	0.59	0.56
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.020	0.013	0.011	0.010
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.9	1.7	1.6	1.5
Passenger Emissions Intensity (kg CO_2e / pkt)	0.14	0.12	0.11	0.10
Passenger Vehicle Energy Intensity (MJ / vkt)	3.1	2.7	2.5	2.3
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.22	0.19	0.17	0.15
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,513	$1,433	$1,305	$1,234
Freight Energy Intensity (MJ / tkt)	1.3	1.2	1.2	1.2
Freight Emissions Intensity (kg CO_2e / tkt)	0.09	0.09	0.08	0.08
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	85.5	93.0	93.1	93.2
Electricity Generation				
Energy Intensity (GJ / MWh)	3.9	3.9	3.9	3.9
Emissions Intensity (t CO_2e / MWh)	0.01	0.01	0.01	0.01
Renewable Generation (TWh)	213	237	273	318
Nuclear Generation (TWh)	6	7	9	10
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	3	5	6	7
CCS Generation (TWh)	0	0	1	1
Other Generation (TWh)	1	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	NA	NA	NA	NA
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	NA	NA	NA	NA
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Reference case – Atlantic Provinces

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	2	1	1	1
Commercial	3	3	4	5
Transportation	22	21	21	21
Manufacturing Industry	4	4	4	4
Landfills	3	3	3	2
Supply Sectors				
Electricity Generation	13	9	9	11
Petroleum Refining	4	4	4	4
Crude Oil	0	0	0	0
Natural Gas	2	2	2	2
Coal Mining	0	0	0	0
Biofuels Manufacturing	0	0	0	0
Total	52	47	47	50

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	91	91	94	101
Commercial	86	100	116	135
Transportation	299	295	302	314
Manufacturing Industry	147	151	159	168
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	429	405	416	447
Petroleum Refining	64	63	65	66
Crude Oil	3	2	1	1
Natural Gas	36	30	27	24
Coal Mining	0	0	0	0
Biofuels Manufacturing	0	1	2	2
Total	1,155	1,138	1,182	1,259

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	154	179	188	190
Coal	109	94	101	128
Refined Petroleum Products	402	347	346	355
Electricity	164	169	185	206
Nuclear	50	48	36	30
Biofuel	1	2	9	11
Renewable	241	263	284	304
Other	34	34	33	35
Total	1,155	1,138	1,182	1,259

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	89	95	107	127
Household Emissions Intensity (t CO_2e / household)	1.5	1.3	1.2	1.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.39	0.35	0.32	0.30
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.011	0.009	0.008	0.007
Annual Energy Costs (2005$ / household)	$2,195	$2,410	$2,803	$3,464
Electricity Price (2005¢ / kWh)	10.8	10.8	10.8	10.8
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.4	1.4	1.4	1.4
Emissions Intensity (t CO_2e / m^2 floorspace)	0.048	0.048	0.048	0.047
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.82	0.83	0.84	0.83
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.040	0.039	0.039	0.039
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.7	1.5	1.4	1.4
Passenger Emissions Intensity (kg CO_2e / pkt)	0.12	0.11	0.10	0.09
Passenger Vehicle Energy Intensity (MJ / vkt)	2.9	2.5	2.3	2.2
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.21	0.18	0.16	0.15
Annual Passenger Vehicle Fuel Costs (2005$ / vehicle)	$1,448	$1,387	$1,280	$1,213
Freight Energy Intensity (MJ / tkt)	0.9	0.8	0.8	0.8
Freight Emissions Intensity (kg CO_2e / tkt)	0.06	0.06	0.06	0.06
Average Vehicle Fuel Prices (2005¢ / L gasoline eq.)	88.1	96.1	96.6	96.8
Electricity Generation				
Energy Intensity (GJ / MWh)	5.4	5.0	4.8	4.8
Emissions Intensity (t CO_2e / MWh)	0.16	0.11	0.11	0.12
Renewable Generation (TWh)	55	60	65	70
Nuclear Generation (TWh)	5	4	3	3
Coal Generation (TWh)	10	9	9	12
Natural Gas Generation (TWh)	5	7	7	6
CCS Generation (TWh)	0	1	2	2
Other Generation (TWh)	4	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.1	0.1	0.1	0.1
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.00	0.00	0.00	0.00
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Canada

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	22	9	4	2
Commercial	28	22	18	18
Transportation	183	95	67	68
Manufacturing Industry	63	41	31	27
Landfills	5	5	5	5
Supply Sectors				
Electricity Generation	115	90	64	43
Petroleum Refining	17	9	4	2
Crude Oil	80	57	41	37
Natural Gas	41	31	24	19
Coal Mining	3	3	3	3
Biofuels Manufacturing	2	4	6	7
Total	557	365	266	232

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	1,385	1,429	1,575	1,868
Commercial	1,253	1,315	1,446	1,648
Transportation	2,798	2,556	2,993	3,420
Manufacturing Industry	2,369	2,584	2,931	3,315
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	5,271	7,243	9,140	10,955
Petroleum Refining	315	201	178	191
Crude Oil	2,127	2,450	2,699	2,925
Natural Gas	559	450	375	302
Coal Mining	27	31	35	40
Biofuels Manufacturing	42	164	285	345
Total	16,145	18,423	21,657	25,009

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	3,488	3,338	3,380	3,594
Coal	2,011	2,699	3,400	4,199
Refined Petroleum Products	2,909	1,575	1,219	1,292
Electricity	2,827	3,823	4,755	5,649
Nuclear	1,334	1,812	2,208	2,509
Biofuel	224	1,023	1,749	2,100
Renewable	2,599	3,354	4,070	4,740
Other	753	798	876	926
Total	16,145	18,423	21,657	25,009

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	95	90	94	107
Household Emissions Intensity (t CO_2e / household)	1.5	0.5	0.2	0.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.35	0.28	0.23	0.21
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.008	0.003	0.001	0.001
Increase in Annual Energy Costs (2005$ / household) [1]	$228	$317	$265	$243
Increase in Electricity Price (2005¢ / kWh) [1]	0.7	1.0	0.9	0.8
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.4	1.2	1.1	1.1
Emissions Intensity (t CO_2e / m^2 floorspace)	0.032	0.020	0.014	0.012
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.73	0.59	0.49	0.45
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.024	0.015	0.009	0.008
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.6	1.1	1.1	1.1
Passenger Emissions Intensity (kg CO_2e / pkt)	0.10	0.05	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	2.9	2.0	1.9	1.9
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.20	0.07	0.04	0.04
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$379	$152	$122	$162
Freight Energy Intensity (MJ / tkt)	0.9	0.8	0.9	0.9
Freight Emissions Intensity (kg CO_2e / tkt)	0.05	0.02	0.01	0.01
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	28.4	46.1	42.3	38.2
Electricity Generation				
Energy Intensity (GJ / MWh)	6.1	6.2	6.3	6.4
Emissions Intensity (t CO_2e / MWh)	0.13	0.08	0.04	0.02
Renewable Generation (TWh)	540	703	860	1,013
Nuclear Generation (TWh)	124	168	204	232
Coal Generation (TWh)	111	86	43	5
Natural Gas Generation (TWh)	26	15	9	6
CCS Generation (TWh)	62	193	328	456
Other Generation (TWh)	5	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	1.2	1.2	1.2	1.1
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.04	0.03	0.02	0.01
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$1.18	$1.73	$1.83	$1.93
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	$3.28	$4.65	$5.48	$5.72
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	$0.69	$1.25	$1.65	$1.90

[1] Represents an increase over the reference case

Policy scenario – British Columbia

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	2	1	0	0
Commercial	3	2	2	2
Transportation	28	16	13	13
Manufacturing Industry	6	3	2	2
Landfills	1	1	1	1
Supply Sectors				
Electricity Generation	1	1	1	1
Petroleum Refining	1	0	0	0
Crude Oil	0	0	0	0
Natural Gas	7	6	5	4
Coal Mining	2	1	1	1
Biofuels Manufacturing	0	1	1	1
Total	50	32	26	25

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	140	170	199	244
Commercial	154	175	210	252
Transportation	430	412	494	566
Manufacturing Industry	433	483	544	606
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	458	704	915	1,115
Petroleum Refining	10	0	0	0
Crude Oil	3	3	2	2
Natural Gas	102	93	82	71
Coal Mining	14	14	14	14
Biofuels Manufacturing	7	24	43	53
Total	1,751	2,077	2,504	2,923

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	230	179	168	176
Coal	18	16	15	15
Refined Petroleum Products	421	255	210	211
Electricity	368	537	681	822
Nuclear	0	0	0	0
Biofuel	38	159	277	342
Renewable	669	929	1,149	1,351
Other	6	2	3	6
Total	1,751	2,077	2,504	2,923

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	72	72	79	92
Household Emissions Intensity (t CO_2e / household)	0.9	0.3	0.1	0.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.22	0.18	0.17	0.17
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.004	0.001	0.001	0.000
Increase in Annual Energy Costs (2005$ / household) [1]	$163	$164	$119	$80
Increase in Electricity Price (2005¢ / kWh) [1]	1.2	1.1	0.9	0.6
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.2	1.1	1.0	1.0
Emissions Intensity (t CO_2e / m^2 floorspace)	0.020	0.013	0.010	0.009
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.62	0.57	0.55	0.54
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.017	0.011	0.008	0.008
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.6	1.2	1.1	1.1
Passenger Emissions Intensity (kg CO_2e / pkt)	0.10	0.05	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	2.9	2.0	1.9	1.9
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.19	0.06	0.03	0.03
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$328	$7	-$8	$25
Freight Energy Intensity (MJ / tkt)	0.8	0.8	0.8	0.8
Freight Emissions Intensity (kg CO_2e / tkt)	0.05	0.03	0.02	0.02
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	27.5	35.3	28.8	23.9
Electricity Generation				
Energy Intensity (GJ / MWh)	4.2	4.4	4.5	4.5
Emissions Intensity (t CO_2e / MWh)	0.01	0.00	0.00	0.00
Renewable Generation (TWh)	107	155	197	237
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	2	1	1	1
CCS Generation (TWh)	1	5	8	10
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.3	0.3	0.3	0.3
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.02	0.02	0.01	0.01
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$0.68	$1.21	$1.14	$1.02
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Alberta

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	5	3	1	1
Commercial	4	3	2	2
Transportation	28	15	10	10
Manufacturing Industry	8	4	3	2
Landfills	0	0	0	0
Supply Sectors				
Electricity Generation	57	44	32	20
Petroleum Refining	4	3	2	1
Crude Oil	78	55	40	36
Natural Gas	25	17	12	9
Coal Mining	1	1	2	2
Biofuels Manufacturing	0	1	1	1
Total	211	147	105	84

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	169	156	162	191
Commercial	166	168	177	192
Transportation	426	386	449	519
Manufacturing Industry	311	339	381	435
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	990	1,430	1,866	2,257
Petroleum Refining	86	73	70	74
Crude Oil	2,096	2,425	2,678	2,907
Natural Gas	323	243	188	136
Coal Mining	10	12	15	18
Biofuels Manufacturing	7	27	50	62
Total	4,583	5,259	6,038	6,791

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	1,835	1,974	2,084	2,229
Coal	1,084	1,380	1,683	1,989
Refined Petroleum Products	479	300	255	293
Electricity	375	546	706	837
Nuclear	0	0	0	0
Biofuel	34	155	280	345
Renewable	136	177	220	257
Other	640	727	810	841
Total	4,583	5,259	6,038	6,791

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	118	95	89	97
Household Emissions Intensity (t CO_2e / household)	3.8	1.6	0.7	0.4
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.50	0.33	0.24	0.20
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.019	0.007	0.002	0.001
Increase in Annual Energy Costs (2005$ / household) [1]	$225	$421	$363	$347
Increase in Electricity Price (2005¢ / kWh) [1]	1.1	1.5	1.3	1.2
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.4	1.2	1.1	1.0
Emissions Intensity (t CO_2e / m^2 floorspace)	0.037	0.023	0.015	0.012
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.82	0.67	0.53	0.46
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.029	0.019	0.011	0.008
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.6	1.2	1.1	1.1
Passenger Emissions Intensity (kg CO_2e / pkt)	0.11	0.05	0.04	0.04
Passenger Vehicle Energy Intensity (MJ / vkt)	3.1	2.2	2.0	2.0
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.21	0.08	0.06	0.06
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$416	$256	$219	$264
Freight Energy Intensity (MJ / tkt)	0.7	0.6	0.6	0.6
Freight Emissions Intensity (kg CO_2e / tkt)	0.04	0.02	0.00	0.00
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	28.8	53.3	50.8	47.0
Electricity Generation				
Energy Intensity (GJ / MWh)	9.0	8.9	8.9	9.1
Emissions Intensity (t CO_2e / MWh)	0.51	0.27	0.15	0.08
Renewable Generation (TWh)	12	20	29	35
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	56	41	22	2
Natural Gas Generation (TWh)	10	7	4	3
CCS Generation (TWh)	32	94	155	209
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	1.3	1.3	1.2	1.2
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.05	0.03	0.02	0.01
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$1.71	$2.40	$2.49	$2.63
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	$3.28	$4.65	$5.48	$5.72
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	$0.69	$1.25	$1.65	$1.90

[1] Represents an increase over the reference case

Policy scenario – Saskatchewan

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	1	0	0	0
Commercial	1	1	1	1
Transportation	7	3	2	2
Manufacturing Industry	2	1	1	2
Landfills	0	0	0	0
Supply Sectors				
Electricity Generation	15	11	7	5
Petroleum Refining	1	0	0	0
Crude Oil	2	1	1	1
Natural Gas	3	2	2	2
Coal Mining	0	0	0	0
Biofuels Manufacturing	0	0	0	0
Total	31	21	15	12

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	35	29	28	31
Commercial	45	43	44	48
Transportation	111	97	105	114
Manufacturing Industry	55	66	84	109
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	247	322	412	500
Petroleum Refining	11	5	3	4
Crude Oil	23	19	16	13
Natural Gas	33	26	23	20
Coal Mining	3	4	6	7
Biofuels Manufacturing	2	8	11	12
Total	563	620	733	859

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	140	121	121	127
Coal	192	251	319	396
Refined Petroleum Products	121	59	40	41
Electricity	75	106	138	167
Nuclear	0	0	0	0
Biofuel	8	46	67	75
Renewable	24	35	46	52
Other	3	2	1	2
Total	563	620	733	859

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	84	75	76	88
Household Emissions Intensity (t CO_2e / household)	1.6	0.4	0.1	0.1
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.39	0.28	0.23	0.21
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.011	0.003	0.001	0.000
Increase in Annual Energy Costs (2005$ / household) [1]	$188	$247	$212	$241
Increase in Electricity Price (2005¢ / kWh) [1]	0.5	0.8	0.9	1.0
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.5	1.3	1.1	1.1
Emissions Intensity (t CO_2e / m^2 floorspace)	0.043	0.027	0.019	0.017
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.91	0.70	0.58	0.51
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.036	0.023	0.015	0.013
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.8	1.3	1.2	1.2
Passenger Emissions Intensity (kg CO_2e / pkt)	0.12	0.04	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	3.1	2.1	2.0	2.0
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.20	0.06	0.04	0.04
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$375	$46	$54	$99
Freight Energy Intensity (MJ / tkt)	1.3	1.2	1.2	1.3
Freight Emissions Intensity (kg CO_2e / tkt)	0.08	0.02	0.01	0.00
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	27.6	37.8	35.0	30.7
Electricity Generation				
Energy Intensity (GJ / MWh)	9.1	8.8	8.9	9.0
Emissions Intensity (t CO_2e / MWh)	0.54	0.30	0.15	0.09
Renewable Generation (TWh)	6	9	12	13
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	13	10	4	1
Natural Gas Generation (TWh)	2	1	0	0
CCS Generation (TWh)	6	17	30	41
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.2	0.2	0.2	0.2
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.02	0.01	0.01	0.01
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$1.11	$1.55	$1.66	$1.84
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Manitoba

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	0	0	0	0
Commercial	1	1	1	1
Transportation	5	2	1	1
Manufacturing Industry	1	0	0	0
Landfills	0	0	0	0
Supply Sectors				
Electricity Generation	0	0	0	0
Petroleum Refining	NA	NA	NA	NA
Crude Oil	0	0	0	0
Natural Gas	1	0	0	0
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	0	0	0
Total	8	4	3	3

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	46	48	56	69
Commercial	58	62	73	85
Transportation	76	62	67	73
Manufacturing Industry	38	41	46	51
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	189	227	262	299
Petroleum Refining	NA	NA	NA	NA
Crude Oil	2	1	1	1
Natural Gas	9	7	6	5
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	1	4	6	6
Total	418	454	516	590

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	41	28	28	32
Coal	5	1	1	0
Refined Petroleum Products	72	31	21	21
Electricity	109	143	172	203
Nuclear	0	0	0	0
Biofuel	5	27	40	46
Renewable	185	223	254	289
Other	0	0	0	0
Total	418	454	516	590

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	91	99	113	140
Household Emissions Intensity (t CO_2e / household)	0.6	0.1	0.0	0.0
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.34	0.30	0.27	0.26
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.003	0.000	0.000	0.000
Increase in Annual Energy Costs (2005$ / household) [1]	$87	$125	$97	$84
Increase in Electricity Price (2005¢ / kWh) [1]	0.4	0.4	0.3	0.2
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.4	1.3	1.3	1.2
Emissions Intensity (t CO_2e / m^2 floorspace)	0.023	0.012	0.010	0.010
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.69	0.61	0.58	0.57
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.015	0.008	0.007	0.007
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.9	1.3	1.3	1.3
Passenger Emissions Intensity (kg CO_2e / pkt)	0.12	0.05	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	3.2	2.1	2.0	2.1
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.21	0.05	0.02	0.02
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$361	-$184	-$214	-$149
Freight Energy Intensity (MJ / tkt)	0.8	0.7	0.7	0.8
Freight Emissions Intensity (kg CO_2e / tkt)	0.04	0.01	0.00	0.00
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	26.2	19.7	10.3	6.5
Electricity Generation				
Energy Intensity (GJ / MWh)	3.7	3.7	3.7	3.7
Emissions Intensity (t CO_2e / MWh)	0.01	0.00	0.00	0.00
Renewable Generation (TWh)	51	61	70	80
Nuclear Generation (TWh)	0	0	0	0
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	0	0	0	0
CCS Generation (TWh)	0	1	1	1
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.3	0.3	0.3	0.3
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.03	0.02	0.02	0.02
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$1.10	$1.75	$1.81	$1.84
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Ontario

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	12	5	2	1
Commercial	14	11	9	9
Transportation	62	31	22	23
Manufacturing Industry	29	21	16	15
Landfills	1	1	2	2
Supply Sectors				
Electricity Generation	30	30	22	16
Petroleum Refining	5	1	1	0
Crude Oil	0	0	0	0
Natural Gas	4	3	3	3
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	1	2	2	3
Total	157	105	79	72

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	570	574	630	757
Commercial	503	519	546	609
Transportation	950	887	1,068	1,244
Manufacturing Industry	747	831	971	1,127
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	1,946	2,925	3,837	4,709
Petroleum Refining	84	29	12	17
Crude Oil	0	0	0	0
Natural Gas	57	51	49	45
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	13	61	109	133
Total	4,870	5,876	7,223	8,642

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	953	783	743	788
Coal	570	944	1,302	1,729
Refined Petroleum Products	943	487	356	386
Electricity	801	1,197	1,559	1,906
Nuclear	1,190	1,637	2,026	2,331
Biofuel	68	367	641	772
Renewable	309	446	582	707
Other	35	16	13	24
Total	4,870	5,876	7,223	8,642

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	100	90	90	101
Household Emissions Intensity (t CO_2e / household)	2.1	0.8	0.3	0.2
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.31	0.23	0.19	0.16
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.010	0.004	0.002	0.001
Increase in Annual Energy Costs (2005$ / household) [1]	$241	$356	$299	$284
Increase in Electricity Price (2005¢ / kWh) [1]	0.5	0.7	0.7	0.8
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.4	1.2	1.0	1.0
Emissions Intensity (t CO_2e / m^2 floorspace)	0.039	0.026	0.017	0.014
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.75	0.57	0.41	0.34
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.029	0.019	0.010	0.007
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.4	1.0	0.9	0.9
Passenger Emissions Intensity (kg CO_2e / pkt)	0.10	0.04	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	2.9	1.9	1.8	1.8
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.19	0.07	0.05	0.05
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$390	$172	$159	$200
Freight Energy Intensity (MJ / tkt)	1.1	1.0	1.1	1.1
Freight Emissions Intensity (kg CO_2e / tkt)	0.07	0.03	0.01	0.01
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	28.7	48.4	46.5	42.8
Electricity Generation				
Energy Intensity (GJ / MWh)	8.5	8.5	8.5	8.5
Emissions Intensity (t CO_2e / MWh)	0.13	0.09	0.05	0.03
Renewable Generation (TWh)	57	89	122	153
Nuclear Generation (TWh)	110	152	188	216
Coal Generation (TWh)	33	31	16	2
Natural Gas Generation (TWh)	8	4	3	2
CCS Generation (TWh)	19	68	124	182
Other Generation (TWh)	0	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.3	0.3	0.3	0.3
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.02	0.01	0.01	0.01
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$0.73	$1.43	$1.51	$1.51
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Québec

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	1	0	0	0
Commercial	3	2	2	2
Transportation	36	18	12	13
Manufacturing Industry	15	9	6	4
Landfills	1	1	1	1
Supply Sectors				
Electricity Generation	1	0	0	0
Petroleum Refining	3	2	1	0
Crude Oil	NA	NA	NA	NA
Natural Gas	0	0	0	0
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	0	1	1	1
Total	62	34	24	23

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	341	370	415	485
Commercial	252	269	309	362
Transportation	563	498	577	654
Manufacturing Industry	644	681	752	824
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	979	1,169	1,364	1,569
Petroleum Refining	66	43	38	40
Crude Oil	NA	NA	NA	NA
Natural Gas	6	6	6	6
Coal Mining	NA	NA	NA	NA
Biofuels Manufacturing	9	29	48	57
Total	2,860	3,064	3,510	3,996

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	183	149	145	152
Coal	30	24	22	20
Refined Petroleum Products	566	280	202	208
Electricity	904	1,065	1,234	1,418
Nuclear	87	112	128	133
Biofuel	50	201	334	396
Renewable	1,002	1,207	1,423	1,646
Other	38	25	23	25
Total	2,860	3,064	3,510	3,996

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	95	101	112	131
Household Emissions Intensity (t CO_2e / household)	0.2	0.0	0.1	0.0
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.45	0.41	0.39	0.36
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.001	0.000	0.000	0.000
Increase in Annual Energy Costs (2005$ / household) [1]	$270	$334	$280	$226
Increase in Electricity Price (2005¢ / kWh) [1]	0.7	0.9	0.7	0.5
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.6	1.4	1.4	1.4
Emissions Intensity (t CO_2e / m^2 floorspace)	0.021	0.011	0.009	0.009
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.68	0.59	0.55	0.54
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.015	0.008	0.007	0.007
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.7	1.2	1.1	1.1
Passenger Emissions Intensity (kg CO_2e / pkt)	0.11	0.05	0.03	0.03
Passenger Vehicle Energy Intensity (MJ / vkt)	2.9	2.0	1.9	1.9
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.20	0.07	0.04	0.04
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$373	$153	$79	$108
Freight Energy Intensity (MJ / tkt)	1.0	0.9	1.0	1.0
Freight Emissions Intensity (kg CO_2e / tkt)	0.06	0.02	0.01	0.01
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	28.2	44.1	37.3	32.4
Electricity Generation				
Energy Intensity (GJ / MWh)	3.9	3.9	3.9	3.9
Emissions Intensity (t CO_2e / MWh)	0.00	0.00	0.00	0.00
Renewable Generation (TWh)	241	286	335	389
Nuclear Generation (TWh)	8	10	12	12
Coal Generation (TWh)	0	0	0	0
Natural Gas Generation (TWh)	1	1	0	0
CCS Generation (TWh)	1	2	4	4
Other Generation (TWh)	1	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	NA	NA	NA	NA
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	NA	NA	NA	NA
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Policy scenario – Atlantic Provinces

Greenhouse Gas Emissions (Mt CO_2e)

	2020	2030	2040	2050
Demand Sectors				
Residential	1	0	0	0
Commercial	2	1	1	1
Transportation	16	9	7	7
Manufacturing Industry	3	2	2	2
Landfills	0	0	0	0
Supply Sectors				
Electricity Generation	11	4	2	1
Petroleum Refining	3	2	1	1
Crude Oil	0	0	0	0
Natural Gas	2	1	1	1
Coal Mining	0	0	0	0
Biofuels Manufacturing	0	0	0	0
Total	39	22	15	13

Energy Consumption (PJ)

	2020	2030	2040	2050
Demand Sectors				
Residential	84	82	84	92
Commercial	76	79	86	99
Transportation	244	214	233	250
Manufacturing Industry	141	143	152	162
Landfills	NA	NA	NA	NA
Supply Sectors				
Electricity Generation	461	466	483	506
Petroleum Refining	58	52	54	56
Crude Oil	3	2	1	1
Natural Gas	30	25	22	19
Coal Mining	0	0	0	0
Biofuels Manufacturing	4	12	19	22
Total	1,101	1,074	1,135	1,207

Energy Consumption by Fuel Type (PJ)

	2020	2030	2040	2050
Natural Gas	106	104	92	91
Coal	112	83	58	50
Refined Petroleum Products	307	163	135	133
Electricity	194	229	265	295
Nuclear	57	62	54	45
Biofuel	21	68	110	126
Renewable	274	337	396	439
Other	31	27	26	28
Total	1,101	1,074	1,135	1,207

Detailed Sectoral Results

	2020	2030	2040	2050
Residential				
Household Energy Intensity (GJ / household)	86	87	96	117
Household Emissions Intensity (t CO_2e / household)	0.6	0.2	0.0	0.0
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.36	0.30	0.25	0.24
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.005	0.001	0.000	0.000
Increase in Annual Energy Costs (2005$ / household) [1]	$222	$333	$303	$373
Increase in Electricity Price (2005¢ / kWh) [1]	0.2	0.8	0.9	1.0
Commercial				
Energy Intensity (GJ / m^2 floorspace)	1.2	1.1	1.1	1.0
Emissions Intensity (t CO_2e / m^2 floorspace)	0.032	0.020	0.012	0.010
Space Heating Energy Intensity (GJ / m^2 floorspace)	0.67	0.60	0.54	0.52
Space Heating Emissions Intensity (t CO_2e / m^2 floorspace)	0.027	0.017	0.010	0.007
Transportation				
Passenger Energy Intensity (MJ / pkt)	1.6	1.2	1.1	1.1
Passenger Emissions Intensity (kg CO_2e / pkt)	0.11	0.06	0.04	0.04
Passenger Vehicle Energy Intensity (MJ / vkt)	2.7	1.9	1.8	1.8
Passenger Vehicle Emissions Intensity (kg CO_2e / vkt)	0.19	0.08	0.06	0.06
Increase in Annual Passenger Vehicle Fuel Costs (2005$ / vehicle) [1]	$362	$268	$234	$295
Freight Energy Intensity (MJ / tkt)	0.7	0.7	0.7	0.7
Freight Emissions Intensity (kg CO_2e / tkt)	0.04	0.03	0.02	0.01
Increase in Average Vehicle Fuel Prices (2005¢ / L gasoline eq.) [1]	28.9	58.6	55.7	53.2
Electricity Generation				
Energy Intensity (GJ / MWh)	5.2	4.7	4.4	4.2
Emissions Intensity (t CO_2e / MWh)	0.13	0.04	0.02	0.01
Renewable Generation (TWh)	66	81	96	107
Nuclear Generation (TWh)	5	6	5	4
Coal Generation (TWh)	10	5	1	0
Natural Gas Generation (TWh)	2	1	0	0
CCS Generation (TWh)	2	6	7	8
Other Generation (TWh)	4	0	0	0
Petroleum Extraction				
Petroleum Extraction Energy Intensity (GJ / barrel)	0.1	0.1	0.1	0.1
Petroleum Extraction Emissions Intensity (t CO_2e / barrel)	0.00	0.00	0.00	0.00
Increase in Cost of Conventional Oil Production (2005$ / barrel) [1]	$0.37	$0.67	$0.87	$0.91
Increase in Cost of Synthetic Crude Production (2005$ / barrel) [1]	NA	NA	NA	NA
Increase in Cost of Blended Bitumen Production (2005$ / barrel) [1]	NA	NA	NA	NA

[1] Represents an increase over the reference case

Appendix B – Description of CIMS

Introduction to the CIMS model

CIMS has a detailed representation of technologies that produce goods and services throughout the economy and attempts to simulate capital stock turnover and choice between these technologies realistically. It also includes a representation of equilibrium feedbacks, such that supply and demand for energy intensive goods and services adjusts to reflect policy.

CIMS simulations reflect the energy, economic and physical output, greenhouse gas emissions, and CAC emissions from its sub-models as shown in Table 99. CIMS does not include solvent, or hydrofluorocarbon (HFC) emissions. CIMS covers nearly all CAC emissions in Canada except those from open sources (like forest fires, soils, and dust from roads).

Table 99: Sector Sub-models in CIMS

Sector	*BC*	*Alberta*	*Sask.*	*Manitoba*	*Ontario*	*Quebec*	*Atlantic*
Residential							
Commercial/Institutional							
Transportation							
Personal							
Freight							
Industry							
Chemical Products							
Industrial Minerals							
Iron and Steel							
Non-Ferrous Metal Smelting*							
Metals and Mineral Mining							
Other Manufacturing							
Pulp and Paper							
Energy Supply							
Coal Mining							
Electricity Generation							
Natural Gas Extraction							
Petroleum Crude Extraction							
Petroleum Refining							
Ethanol							
Biodiesel							
Waste							

* Metal smelting includes Aluminium.

Model structure and simulation of capital stock turnover

As a technology vintage model, CIMS tracks the evolution of capital stocks over time through retirements, retrofits, and new purchases, in which consumers and businesses make sequential acquisitions with limited foresight about the future. This is particularly important for understanding the implications of alternative time paths for emissions reductions. The model calculates energy costs (and emissions) for each energy service in the economy, such as heated commercial floor space or person kilometres travelled. In each time period, capital stocks are retired according to an age-dependent function (although retrofit of un-retired stocks is possible if warranted by changing economic conditions), and demand for new stocks grows or declines depending on the initial exogenous forecast of economic output, and then the subsequent interplay of energy supply-demand with the macroeconomic module. A model simulation iterates between energy supply-demand and the macroeconomic module until energy price changes fall below a threshold value, and repeats this convergence procedure in each subsequent five-year period of a complete run.

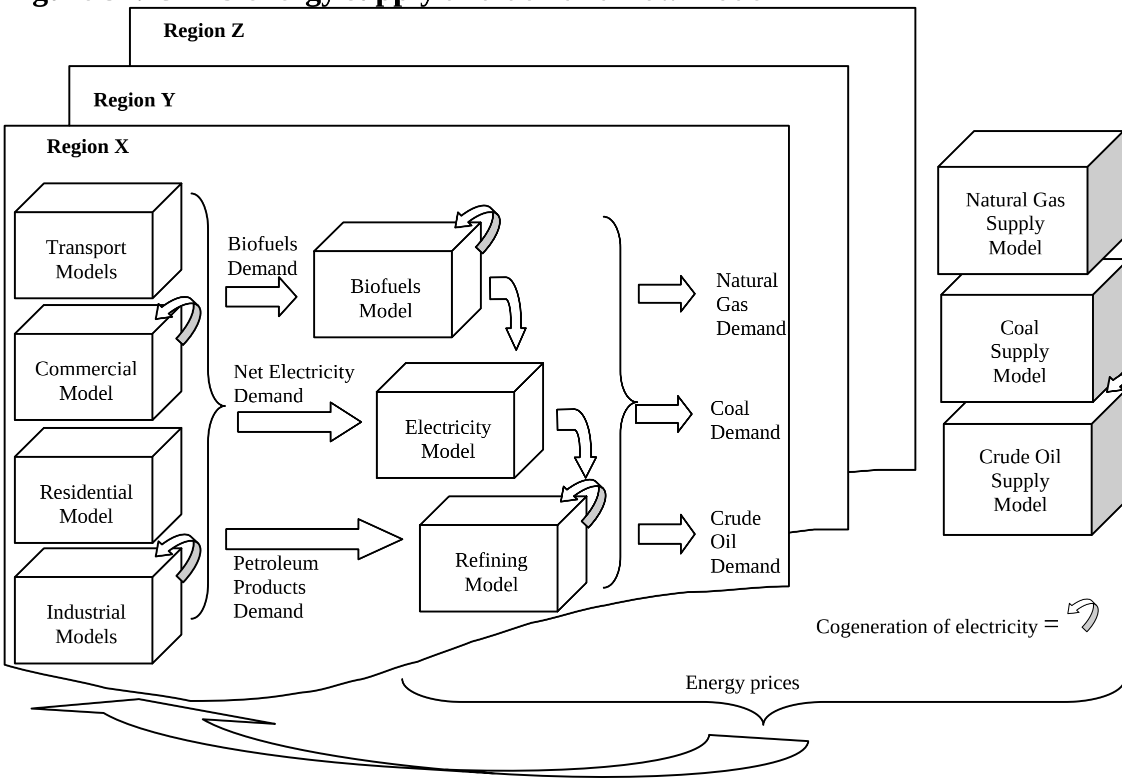
CIMS simulates the competition of technologies at each energy service node in the economy based on a comparison of their life cycle cost (LCC) and some technology-specific controls, such as a maximum market share limit in the cases where a technology is constrained by physical, technical or regulatory means from capturing all of a market. Instead of basing its simulation of technology choices only on financial costs and social discount rates, CIMS applies a definition of LCC that differs from that of bottom-up analysis by including intangible costs that reflect consumer and business preferences and the implicit discount rates revealed by real-world technology acquisition behaviour.

Equilibrium feedbacks in CIMS

CIMS is an integrated, energy-economy equilibrium model that simulates the interaction of energy supply-demand and the macroeconomic performance of key sectors of the economy, including trade effects. Unlike most computable general equilibrium models, however, the current version of CIMS does not equilibrate government budgets and the markets for employment and investment. Also, its representation of the economy's inputs and outputs is skewed toward energy supply, energy intensive industries, and key energy end-uses in the residential, commercial/institutional and transportation sectors.

CIMS estimates the effect of a policy by comparing a business-as-usual forecast to one where the policy is added to the simulation. The model solves for the policy effect in two phases in each run period. In the first phase, an energy policy (e.g., ranging from a national emissions price to a technology specific constraint or subsidy, or some combination thereof) is first applied to the final goods and services production side of the economy, where goods and services producers and consumers choose capital stocks based on CIMS' technological choice functions. Based on this initial run, the model then calculates the demand for electricity, refined petroleum products and primary energy commodities, and calculates their cost of production. If the price of any of these commodities has changed by a threshold amount from the business-as-usual case, then supply and demand are considered to be out of equilibrium, and the model is re-run based on prices calculated from the new costs of production. The model will re-run until a new equilibrium set of energy prices and demands is reached. Figure 57 provides a schematic of this process. For this project, while the quantities produced of all energy commodities were set endogenously using demand and supply balancing, endogenous pricing was used only for electricity and refined petroleum products; natural gas, crude oil and coal prices remained at exogenously forecast levels (described later in this section), since Canada is assumed to be a price-taker for these fuels.

Figure 57: CIMS energy supply and demand flow model



In the second phase, once a new set of energy prices and demands under policy has been found, the model measures how the cost of producing traded goods and services has changed given the new energy prices and other effects of the policy. For internationally traded goods, such as lumber and passenger vehicles, CIMS adjusts demand using price elasticities that provide a long-run demand response that blends domestic and international demand for these goods (the "Armington" specification).[52] Freight transportation is driven by changes in the combined value added of the industrial sectors, while personal transportation is adjusted using a personal kilometres-travelled elasticity (-0.02). Residential and commercial floor space is adjusted by a sequential substitution of home energy consumption vs. other goods (0.5), consumption vs. savings (1.29) and goods vs. leisure (0.82). If demand for any good or service has shifted more than a threshold amount, supply and demand are considered to be out of balance and the model re-runs using these new demands. The model continues re-running until both energy and goods and services supply and demand come into balance, and repeats this balancing procedure in each subsequent five-year period of a complete run.

Empirical basis of parameter values

Technical and market literature provide the conventional bottom-up data on the costs and energy efficiency of new technologies. Because there are few detailed surveys of the annual energy consumption of the individual capital stocks tracked by the model

52 CIMS' Armington elasticities are econometrically estimated from 1960-1990 data. If price changes fall outside of these historic ranges, the elasticities offer less certainty.

(especially smaller units), these must be estimated from surveys at different levels of technological detail and by calibrating the model's simulated energy consumption to real-world aggregate data for a base year.

Fuel-based greenhouse gas emissions are calculated directly from CIMS' estimates of fuel consumption and the greenhouse gas coefficient of the fuel type. Process-based greenhouse gas emissions are estimated based on technological performance or chemical stoichiometric proportions. CIMS tracks the emissions of all types of greenhouse gas emissions, and reports these emissions in terms of carbon dioxide equivalents.[53]

Both process-based and fuel-based CAC emissions are estimated in CIMS. Emissions factors come from the US Environmental Protection Agency's FIRE 6.23 and AP-42 databases, the MOBIL 6 database, calculations based on Canada's National Pollutant Release Inventory, emissions data from Transport Canada, and the California Air Resources Board.

Estimation of behavioural parameters is through a combination of literature review, judgment, and meta-analysis, supplemented with the use of discrete choice surveys for estimating models whose parameters can be transposed into behavioural parameters in CIMS.

Simulating endogenous technological change with CIMS

CIMS includes two functions for simulating endogenous change in individual technologies' characteristics in response to policy: a declining capital cost function and a declining intangible cost function. The declining capital cost function links a technology's financial cost in future periods to its cumulative production, reflecting economies-of-learning and scale (e.g., the observed decline in the cost of wind turbines as their global cumulative production has risen). The declining capital cost function is composed of two additive components: one that captures Canadian cumulative production and one that captures global cumulative production. The declining intangible cost function links the intangible costs of a technology in a given period with its market share in the previous period, reflecting improved availability of information and decreased perceptions of risk as new technologies become increasingly integrated into the wider economy (e.g., the "champion effect" in markets for new technologies); if a popular and well respected community member adopts a new technology, the rest of the community becomes more likely to adopt the technology.

[53] CIMS uses the 2001 100-year global warming potential estimates from Intergovernmental Panel on Climate Change, 2001, "Climate Change 2001: The Scientific Basis", Cambridge, UK, Cambridge University Press.

Attachment 2.0

September 9, 2009

Terasen Gas Inc.

Five Year Rate Reset Cumulative Redeemable Preferred Shares Series 1

Indicative Termsheet for Discussion Purposes

Terms and Conditions

Issuer: Terasen Gas Inc. (the "Corporation")

Issue: ●% Five Year Rate Reset Cumulative Redeemable Preferred Shares Series 1 (the "Series 1 Preferred Shares")

Issue Size: Treasury offering of $50,000,000 or 2,000,000 Preferred Shares

Underwriters' Option: The Company has granted the Underwriters an option exercisable at the Issue Price, in whole or in part, up to 48 hours prior to the closing of the Offering to purchase up to 300,000 Preferred Shares Series 1 ($7,500,000).

Issue Price: $25.00 per Series 1 Preferred Share

Dividends:

Initial Fixed Rate Period:

- Fixed, cumulative, preferential cash dividends payable quarterly on the first business day of March, June, September and December at an annual rate of $● per Series 1 Preferred Share, for the initial period ending on December 1, 2014 (the "Initial Fixed Rate Period"). The first of such dividends, if declared, shall be payable on December 1, 2009, and shall be $● per Series 1 Preferred Share, based on the anticipated closing of the treasury offering of the Series 1 Preferred Shares on ●, 2009.

Subsequent Fixed Rate Periods:

- For every five-year period after the Initial Fixed Rate Period (a "Subsequent Fixed Rate Period"), the Corporation will determine on the 30th day prior to the first day of the Subsequent Fixed Rate Period, the annual fixed dividend rate applicable to that Subsequent Fixed Rate Period (the "Annual Fixed Dividend Rate").
- The Annual Fixed Dividend Rate will be equal to the 5-Year Government of Canada Bond Yield ("GCAN5YR") as quoted on Bloomberg (see quote for "GCAN5YR <INDEX>") or comparable sources at 10:00 a.m. (Toronto time) on the 30th day prior to the first day of a Subsequent Fixed Rate Period plus ●%.
- Fixed, cumulative, preferential cash dividends payable quarterly on the first business day of March, June, September and December, based on the Annual Fixed Dividend Rate.

Conversion:

Election to Convert:

- On December 1, 2014, and on December 1 every five years thereafter (the "Series 1 Conversion Date"), the holders of Series 1 Preferred Shares will have the right to elect to convert (subject to the Automatic Conversion provision described below) any or all of their Series 1 Preferred Shares into an equal number of Floating Rate Cumulative Redeemable Preferred Shares Series 2 (the "Series 2 Preferred Shares"). Should any such December 1 not be a business day, the Series 1 Conversion Date will be the next succeeding business day.

Election Notice:

- Holders of Series 1 Preferred Shares who elect to convert their Series 1 Preferred Shares into Series 2 Preferred Shares on the Series 1 Conversion Date are required to provide the Corporation with written notice (an "Election Notice") on a date not earlier than the 30th day and not later than 5:00 p.m. (Toronto time) on the 15th day preceding the applicable Series 1 Conversion Date. Once received by the Corporation, an Election

Notice is irrevocable.

Automatic Conversion:

- If the Corporation determines that after giving effect to any Election Notices received by the Corporation during the time fixed therefor there would be less than 1,000,000 Series 1 Preferred Shares issued and outstanding on the applicable Series 1 Conversion Date, then all of the issued and outstanding Series 1 Preferred Shares will automatically be converted on such Series 1 Conversion Date into an equal number of Series 2 Preferred Shares (“Automatic Conversion”).
- Holders of Series 1 Preferred Shares will not be entitled to convert their shares into Series 2 Preferred Shares if the Corporation determines that there would remain outstanding on a Series 1 Conversion Date less than 1,000,000 Series 2 Preferred Shares, after having taken into account all Series 1 Preferred Shares tendered for conversion into Series 2 Preferred Shares and all Series 2 Preferred Shares tendered for conversion into Series 1 Preferred Shares.

Notice of Series 1 Conversion Date and next Annual Fixed Dividend Rate:

- Notice of a Series 1 Conversion Date and a form of Election Notice will be given by the Corporation at least 30 days and not more than 60 days prior to the Series 1 Conversion Date.
- Notice of the Annual Fixed Dividend Rate for the upcoming Subsequent Fixed Rate Period will be provided by the Corporation on the 30th day prior to each Series 1 Conversion Date.

Not electing to convert and continuing to hold Series 1 Preferred Shares:

- If the Corporation does not receive an Election Notice from a holder of Series 1 Preferred Shares during the time fixed therefor, then the Series 1 Preferred Shares of that holder shall not be converted (except in the case of an Automatic Conversion).

Redemption for Cash: The Series 1 Preferred Shares will not be redeemable prior to December 1, 2014. On December 1, 2014, and on December 1 every five years thereafter, on not more than 60 nor less than 30 days’ notice, the Corporation may, at its option, redeem all or any number of the then outstanding Series 1 Preferred Shares upon payment in cash for each Series 1 Preferred Share so redeemed of an amount equal to $25.00 per Series 1 Preferred Share together with all accrued and unpaid dividends to the date fixed for redemption. Should any such December 1 not be a business day, the redemption date in that year will be the next succeeding business day.

Purchase for Cancellation: The Corporation may at any time or times purchase for cancellation all or any part of the Series 1 Preferred Shares on the open market, by private agreement or otherwise at the lowest price or prices at which in the opinion of the Board of Directors of the Corporation such shares are obtainable.

Rights on Liquidation: In the event of the liquidation, dissolution or winding-up of the Corporation, the holders of the Series 1 Preferred Shares will be entitled to receive $25.00 per share together with all accrued and unpaid dividends to the date of payment before any amount shall be paid or any assets of the Corporation distributed to the holders of any common shares or other shares ranking junior to the Series 1 Preferred Shares. The holders of the Series 1 Preferred Shares will not be entitled to share in any further distribution of the property or assets of the Corporation.

Assumed Ratings: DBRS: Pfd-3 (high)
S&P: P-2

Voting: The holders of the Series 1 Preferred Shares are not entitled to any voting rights or to receive notice of or to attend shareholders’ meetings unless dividends on the preferred shares of the Corporation of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series 1 Preferred Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class of shares) and to one vote in respect of each Series 1 Preferred Share held.

Eligibility: Eligible for registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, tax free savings accounts and registered disability savings plans under the Income Tax Act (Canada).

Listing: An application will be made to list the Series 1 Preferred Shares on The Toronto Stock Exchange.

Form of Offering: Bought deal by way of a short form prospectus to be filed in all provinces of Canada (the "Qualifying Jurisdictions").

Tax on Series 1 Preferred Shares: The Corporation will elect to pay tax under Part VI.1 of the Income Tax Act (Canada) such that no tax under Part IV.1 of such Act will be payable by the holders.

Closing: On or about ●, 2009

Terasen Gas

Floating Rate Cumulative Redeemable Preferred Shares Series 2

Terms and Conditions

Issuer: Terasen Gas (the "Corporation")

Issue: Floating Rate Cumulative Redeemable Preferred Shares Series 2 (the "Series 2 Preferred Shares")

Dividends: *Quarterly Dividend Payments:*

- Cumulative preferential cash dividends payable quarterly on the first business day of March, June, September and December (the "Quarterly Dividend Payment Date" and each period a "Quarterly Floating Rate Period") at the Floating Quarterly Dividend Rate (as defined below) on an actual/365 day count basis times $25.00.

Floating Quarterly Dividend Rate:

- The Floating Quarterly Dividend Rate for a quarter will be equal to the 90-day Canadian Treasury Bill Rate ("T-Bill Rate") plus ●%. The T-Bill Rate will be calculated using the 3-month average results, as reported by the Bank of Canada, for the most recent auction preceding the date on which the Floating Quarterly Dividend Rate for such quarter is determined. Auction results are posted on Reuters page BOCBILL.
- The Floating Quarterly Dividend Rate for each Quarterly Floating Rate Period will be determined by the Corporation 30 days prior to the first day of the Quarterly Floating Rate Period.

Conversion: *Election to Convert:*

- On December 1, 2019, and on December 1 every five years thereafter (the "Series 2 Conversion Date"), the holders of Series 2 Preferred Shares have the right to elect to convert (subject to the Automatic Conversion provision described below) any or all of their Series 2 Preferred Shares into an equal number of Five Year Rate Reset Cumulative Redeemable Preferred Shares Series 1 (the "Series 1 Preferred Shares"). Should any such December 1 not be a business day, the Series 2 Conversion Date in that year will be the next succeeding business day.

Election Notice:

- Holders of Series 2 Preferred Shares who elect to convert their Series 2 Preferred Shares into Series 1 Preferred Shares on the Series 2 Conversion Date are required to provide the Corporation with written notice (an "Election Notice") on a date not earlier than the 30th day and not later than 5:00 p.m. (Toronto time) on the 15th day preceding the applicable Series 2 Conversion Date. Once received by the Corporation, an Election Notice is irrevocable.

Automatic Conversion:

- If the Corporation determines that after giving effect to any Election Notices received by the Corporation during the time fixed therefor there would be less than 1,000,000 Series 2 Preferred Shares issued and outstanding on the applicable Series 2 Conversion Date, then all of the issued and outstanding Series 2 Preferred Shares will automatically be converted on such Series 2 Conversion Date into an equal number of Series 1 Preferred Shares ("Automatic Conversion").
- Holders of Series 2 Preferred Shares will not be entitled to convert their shares into Series 1 Preferred Shares if the Corporation determines that there would remain outstanding on a Series 2 Conversion Date less than 1,000,000 Series 1 Preferred Shares, after having taken into account all

Series 2 Preferred Shares tendered for conversion into Series 1 Preferred Shares and all Series 1 Preferred Shares tendered for conversion into Series 2 Preferred Shares.

Notice of Series 2 Conversion Date and next Annual Fixed Dividend Rate:

- Notice of a Series 2 Conversion Date and a form of Election Notice will be given by the Corporation at least 30 days and not more than 60 days prior to the Series 2 Conversion Date.
- Notice of the annual fixed dividend rate on the Series 1 Preferred Shares (the "Annual Fixed Dividend Rate") for the upcoming five-year period, after the initial period ending on December 1, 2014, (a "Subsequent Fixed Rate Period") will be provided by the Corporation on the 30th day prior to each Series 2 Conversion Date.

Not electing to convert and continuing to hold Series 2 Preferred Shares:

- If the Corporation does not receive an Election Notice from a holder of Series 2 Preferred Shares during the time fixed therefor, then the Series 2 Preferred Shares of that holder shall not be converted (except in the case of an Automatic Conversion).

Redemption for Cash: On December 1, 2019, and on December 1 every five years thereafter, on not more than 60 nor less than 30 days' notice, the Corporation may, at its option, redeem all or any number of the then outstanding Series 2 Preferred Shares upon payment in cash for each Series 2 Preferred Share so redeemed of an amount equal to $25.00 per Series 2 Preferred Share together with all accrued and unpaid dividends to the date fixed for redemption. On any other date after December 1, 2014 that is not a Series 2 Conversion Date, on not more than 60 nor less than 30 days' notice, the Corporation may, at its option, redeem all or any part of the then outstanding Series 2 Preferred Shares upon payment in cash for each Series 2 Preferred Share so redeemed of an amount equal to $25.50 per Series 2 Preferred Share together with all accrued and unpaid dividends to the date fixed for redemption. Should any such December 1 not be a business day, the redemption date in that year will be the next succeeding business day.

Purchase for Cancellation: The Corporation may at any time or times purchase for cancellation all or any part of the Series 2 Preferred Shares on the open market, by private agreement or otherwise at the lowest price or prices at which in the opinion of the Board of Directors of the Corporation such shares are obtainable.

Rights on Liquidation: In the event of the liquidation, dissolution or winding-up of the Corporation, the holders of the Series 2 Preferred Shares will be entitled to receive $25.00 per share together with all accrued and unpaid dividends to the date of payment before any amount shall be paid or any assets of the Corporation distributed to the holders of any common shares or other shares ranking junior to the Series 2 Preferred Shares. The holders of the Series 2 Preferred Shares will not be entitled to share in any further distribution of the property or assets of the Corporation.

Voting: The holders of the Series 2 Preferred Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the preferred shares of the Corporation of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series 2 Preferred Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class of shares) and to one vote in respect of each Series 2 Preferred Share held.

Eligibility: Eligible for registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, tax free savings accounts and registered disability savings plans under the Income Tax Act

(Canada).

Listing:	An application will be made to list the Series 2 Preferred Shares on The Toronto Stock Exchange.
Tax on Series 2 Preferred Shares:	The Corporation will elect to pay tax under Part VI.1 of the Income Tax Act (Canada) such that no tax under Part IV.1 of such Act will be payable by the holders.

Attachment 5.0

Company	States of Operation	Deferral Mechanisms	Decoupling/Weather/Rate Design
AGL RESOURCES INC	Georgia, Virginia, New jersey, Florida, Tennessee, Maryland	**GA -** Rider for Pipeline Replacement Costs and Rider for Environmental remediation liabilities	**TN, NJ** (1992)-Declining block rate structure, Weather Normalization Adjustment; **MD, FL**-Flat rate; **VA**-Decoupling; **GA**-straight fixed variable rate design, customer pays 1/12 of annual fixed charges and a predetermined percent of demand day annual capacity charges each month
ATMOS ENERGY CORP	Georgia, Virginia, Kentucky, Tennessee, Mississippi, Louisiana, Louisiana (Trans LA), Texas (Mid-Tex), Texas (West Texas), Texas (Amarillo), Texas (Lubbock), Colorado, Kansas, Missouri (Southeast), Missouri (Northeast), Missouri (West), Iowa, Illinois	Pension and post-retirement benefits; Environmental costs; Rate case expenses; Merger and Integration expenses; Franchise Fees	**MS**-Earnings based automatic ROE Adjustment (Oct 1, 1992); **LA**-Earnings based revenue stabilization clause, rates adjusted annually the achieve the authorized ROE (May 25, 2006); **MO**-Non gas charges for residential and small general service class are recovered through a fixed charge to each customer (Mar 4, 2007); **KY** (2002), **TN** (1991), **MS, LA** (2006), **TX** (2004), **KS** (2003), **VA, GA** (1990)-Weather Normalization Adjustment; **KY**-Declining block rate structure; **TN**, **MS, LA, VA, GA, CO, MO, IL**-Flat per unit rate; **TX**-Flat per unit rate except for industrial which has a declining block rate structure
NEW JERSEY RESOURCES	New Jersey	Deferrals for universal service fund; environmental remediation expenses; post retirement benefits; conservation incentive program	**NJ**-Conservation Incentive Program allows for recovery of margin deficiency associated with non-weather related changes in customer usage limited to the level of Basic Gas Supply Service Charge savings achieved (Oct, 2006); Residential flat rate
NICOR INC	Illinois	Post retirement benefits; Environmental costs; Rate case expenses	**IL**-SFV rate design that recovers 80% of Rate 1 customers' fixed delivery service costs through monthly customer charge (Mar 2009)
NORTHWEST NATURAL GAS CO	Oregon, Washington	Deferral for pipeline integrity management program; pension expense deferral; environmental cost deferral	**OR**-Partial Decoupling Mechanism, margins associated with differences between weather normalized usage and baseline usage for residential and commercial customers are collected into a deferral account; **OR**-Residential general sales and basic firm service have a flat per unit rate, all other rates are declining block rate structures; **WA**-Residential, general sales, and basic firm service have a flat per unit rate, all other rates are declining block rate structures
PIEDMONT NATURAL GAS CO	North Carolina, South Carolina, Tennessee	Deferrals for pension and retirement benefits expense, environmental remediation, demand side management; pipeline integrity expense; uncollected gas costs.	**NC**-Customer Utililization Tracker which decouples the recovery of authorized margins from sales for all reasons including conservation and weather (Nov 3, 2005); **SC**-All expenses recovered throug an earnings based Rate Stabilization mechanism that allows the recovery of all costs to rbring it back to its allowed ROE in its most recent rate case if current margins are outside a 50 basis point dead band. Includes recovery for changes in weather, conservation, and declining use per customer; **TN**-Weather Normalization Adjustment (1991); **NC, SC, TN**-Residential is a flat volumetric charge, other service classes have flat per unit rate or the "value" service option which is a declining block rate structure. All volumetric charges are seasonal.
SOUTH JERSEY INDUSTRIES INC	New Jersey	Environmental remediation costs; Deferred pension and other post-retirement benefit costs; Conservation Incentive Program; Universal service costs; Consumer education program expenses	**NJ**-Conservation Incentive Program adjusts the company's revenues in cases wherein actual usage per customer experienced during an annual period varies from the Baseline Usage Per Customer. Adjustment is applied as a credit or surcharge to customers' bills and will be adjusted to reflect prior year under recoveries or over recoveries. The BUC is reset each time new base rates are placed into effect as the result of a base rate case proceeding; Weather Normalization Adjustment
SOUTHWEST GAS CORP	Arizona, Nevada, California	Post retirement benefits; Low income and conservation program expenses	**CA** Decoupling Tariff; **NV** Declining block rate structure; Can file for decoupling in **NV** during next rate case and has done so
WGL HOLDINGS INC	Maryland, Virginia, District of Columbia	trackers for pension and OPEB expenses	**MD**-Firm Credit Adjustment credit to firm customers of revenue from interruptible customers, Revenue Normalization Adjustment recover/credit deviations from test year non gas revenue approved in rate case adjusted to reflect changes in the number of customers; **VA**-Risk Sharing Mechanism credit to firm customers of revenue from interruptible customers; **MD, VA**-Declining block rate structure

Company	Purchased Gas Cost	Other
AGL RESOURCES INC	**TN, MD, FL, NJ**-Purchased Gas Adjustment Provision **GA** - does not sell gas	**GA**-Pipeline replacement tracking mechanism (approved Sep 3, 1998); **NJ**-Basic gas supply service charge and revenue stabilization for standard offer losses, clean energy program losses and remediation costs;
ATMOS ENERGY CORP	**KY, TX, CO**-Gas Cost Adjustment; **TN, MS, LA, VA, GA, MO, IL**-Purchased Gas Adjustment Rider	**TN, TX, VA, KS**-Bad debt recovery mechanism
NEW JERSEY RESOURCES	**NJ**-Basic Gas Supply Service Charge Rider A	
NICOR INC	**IL**-Purchased Gas Adjustment allows recovery of 100% adjusted on a monthly basis	
NORTHWEST NATURAL GAS CO	**OR, WA**-Purchased Gas Cost Adjustment Schedule P	
PIEDMONT NATURAL GAS CO	**NC, TN**-Purchased Gas Adjustment Clause; **SC**-Gas Cost Hedging program recovers costs over defined benchmark and returns to customers as savings under the defined benchmark	**NC, SC, TN**-Bad debt recovery mechanism
SOUTH JERSEY INDUSTRIES INC	**NJ**-Basic Gas Supply Service Charge Rider A	**NJ**-Remediation Adjustment Clause inteded to recover remediation and/or litigation costs/expenses resulting from the operation or decommissioning of gas manufacturing facilities
SOUTHWEST GAS CORP	Purchased gas adjustment	
WGL HOLDINGS INC	**DC, MD, VA**-Purchased Gas Charge	**DC, MD, VA**-Bad debt recovery mechanism