

CME INTERROGATORY #7

INTERROGATORY

Issue: E35

Reference: Exhibit A2, Tab 1, Schedule 1, page 25
Exhibit A2, Tab 1, Schedule 3

Did EGDI and Union Gas Limited ("Union") have discussions pertaining to the nature of the IRM plans to be proposed for the period 2014 to 2018 inclusive before EGDI determined to proceed with its customized IRM Plan? If so, please provide the following:

- (a) The details of these discussions and explain why EGDI determined that the approach Union has adopted and the Board has approved was not suitable for its circumstances.
- (b) Provide copies of any calculations that EGDI did to apply Union's model to its circumstances for the years 2014 to 2018 inclusive.

RESPONSE

- (a) Enbridge and Union's discussions about their respective IR plans were limited to the information that each utility shared with stakeholders through their consultation processes. Details about why Union's IR model is not suitable for EGD are set out at the response to CCC Interrogatory #4 at Exhibit I.A1.EGDI.CCC.4.
- (b) Please refer to the response to BOMA Interrogatory #2 at Exhibit I.A1.EGDI.BOMA.2

Witnesses: R. Fischer
S. Kancharla
M. Lister

SEC INTERROGATORY #119

INTERROGATORY

Issue E35: What are the regulatory alternatives to the Board approving the Enbridge rate proposal? Are any alternatives to approving the rate proposal appropriate?

Please confirm Enbridge's position that, in the event that the Board hears evidence in this proceeding on the costs Enbridge expects to incur in the years 2014 through 2016, the Board cannot, as a matter of law, set rates on the basis of a formula decoupled from those costs unless it first rejects Enbridge's evidence on cost.

RESPONSE

Enbridge expects the Board to hear the evidence in this Application, including evidence about Enbridge's forecast costs, and will make a decision about the proposed Customized IR plan based on that evidence. Any decision setting an IR framework for 2014 to 2018 will have to allow for just and reasonable rates. Any relevant questions of law related to what the Board can or cannot do in relation to ratesetting under this Application are appropriately addressed in argument.

VECC INTERROGATORY #19

INTERROGATORY

ISSUE E3 5: What are the regulatory alternatives to the Board approving the Enbridge rate proposal? Are any alternatives to approving the rate proposal appropriate?

Evidence Ref: A2/T1/S1page 14, paragraph 34

The referenced paragraph states:

There are few differences between the Customized IR plan, and Enbridge's 1st Generation IR plan. The main difference relates to how the Allowed Revenue amounts are initially set. As explained later in this document, the capital costs component of the Allowed Revenue amounts for 2014 to 2016 takes account of Enbridge's extraordinary requirements over that period. Even so, it does include productivity savings. The O&M component of Allowed Revenues within the Customized IR plan is largely consistent with Enbridge's 1st Generation IR plan. This is confirmed by Concentric Energy Advisors, Inc. ("Concentric"), who have concluded that Enbridge's O&M budgets for 2014 to 2016 are actually lower than would be expected under a conventional I-X type of IR plan. Given that the budgets will change at the same rate for 2017 and 2018, that finding holds true for the entire IR term. (Emphasis added.)

- a) Does this assertion imply that EGO would have been better off by proposing an 1-X IR plan that applied only to cost elements other than those related to capital expenditures?

RESPONSE

Please see the response to Board Staff Interrogatory #9 found at Exhibit I.A1.EGDI.STAFF.9.

Witnesses: R. Fischer
M. Lister

BOARD STAFF INTERROGATORY #70

INTERROGATORY

ISSUE D36: Is Enbridge's proposal for Transactional Services ("TS"), including the classification of transactions within TS and the treatment and sharing of TS revenues, appropriate?

Evidence Ref: C1/T3/S1/para 4

Please provide a summary of transactional service amounts by TS type/category for 2012 actual and the latest forecast for 2013.

RESPONSE

Please see the response to Energy Probe Interrogatory #36 b) at Exhibit I.E36.EGDI.EP.36.

Witnesses: J. Denomy
J. LeBlanc
D. Small

CME INTERROGATORY #12

INTERROGATORY

Issue: E36

Reference: Exhibit C1, Tab 3, Schedule 1

In connection with the Transactional Services ("TS") evidence, please provide the following information:

- (a) List each of the services EGDI classifies as TS.
- (b) Provide a schedule that shows the net amount EGD realized from each of these types of services over the years 2011, 2012 and 2013.
- (c) Separate the TS between upstream transportation pipeline optimization activities and other transactional services.
- (d) What will be the impact on ratepayers, if any, if all upstream transportation optimization activities are classified as upstream transportation cost reductions rather than as TS revenues?

RESPONSE

- a) Enbridge provided a detailed description of the various types of Transactional Services as well as the various attributes of a transaction that would constitute a particular deal as Transactional Services as a part of EB-2012-0046 (Exhibit C, Tab 1, Schedule 6). In summary a commercial arrangement that underpins Enbridge's TS activities can be grouped as either storage optimization or transportation optimization. Storage optimization occurs when Enbridge temporarily stores gas for a third party and generates revenues due to pricing differentials across time. Transportation optimization occurs when Enbridge uses temporarily surplus capacity to deliver gas to a third party at one location while receiving an equivalent volume from that third party at another location. Revenues in this instance are derived from pricing differences in one location versus another. TS activity is in no way allowed to impact Enbridge's ability to meet utility demand and each TS arrangement is structured such that Enbridge is able to fulfill the requirements of its gas supply plan.

Witnesses: J. Denomy
J. LeBlanc
D. Small

- b) Please refer to the response to Energy Probe Interrogatory #36 b) at Exhibit I.E36.EGDI.EP.36 for TS net revenue by transaction type for the period 2010 to 2012 and an estimate of 2013 net revenues.
- c) It is unclear what is considered to be “upstream transportation pipeline optimization” activities. The response to Energy Probe Interrogatory #36 b) at Exhibit I.E36.EGDI.EP.36 broke the transportation optimization activities into the three types of exchanges that were described as part of the evidence in EB-2012-0046 (Exhibit C, Tab 1, Schedule 6).
- d) If the phrase “all upstream transportation optimization activities” intends that base exchanges, STS-RAM exchanges and capacity release exchange transactions described in the response to a) above, are to be classified as upstream transportation cost reductions rather than TS revenues, then gas costs would be reduced by an amount equivalent to the net revenue generated by these activities in a particular year.

However, the Company is unable to provide an estimate of what these amounts will be in the future as the revenues generated by upstream transportation optimization activities are dependent on market conditions throughout any given year. Therefore, the Company could not include as part of the gas cost forecast any amounts related to these types of transactions.

Further, as an additional consequence, the Company would request the elimination of the \$12.0 million reduction currently included in rates for TS activities.

Witnesses: J. Denomy
J. LeBlanc
D. Small

ENERGY PROBE INTERROGATORY #36

INTERROGATORY

Ref: Exhibit C1, Tab 3, Schedule 1

- a) Has EGD's opinion/proposal related to the \$12 million revenue requirement credit and/or the sharing and/or the \$8 million guarantee changed as a result of the settlement agreement between EGD, Union, Gaz Metro and TCPL? Please explain fully.
- b) Please provide the year-to-date and full year forecast for 2013 based on these actuals for the transactional services. Please provide the figures for 2010 through 2012 as well. Please provide all years based on the type of transaction.
- c) Does EGD propose to lock the \$12 million credit into the revenue requirement for 2014 only or does this amount also get locked into the 2015 and 2016 rates?
- d) How does the credit get adjusted for the 2017 and 2018 rates?

RESPONSE

- a) EGD has not changed its proposal related to the \$12.0 million forecast of Transactional Services ("TS") included as a reduction to costs in 2014 or how amounts should be captured net revenue in the Transactional Services Deferral Account ("TSDA") as a result of the recent settlement agreement between EGD, Union, Gaz Metro and TCPL.

As described in its pre-filed evidence at Exhibit C1, Tab 3, Schedule1, the Company believes that there remains a high level of uncertainty around the ability of EGD to generate TS revenue in 2014. Adding to that uncertainty is the fact that EGD itself will potentially have excess TCPL capacity available that it will be trying to release into the marketplace in an effort to avoid potential UDC costs to be borne by the ratepayers. It is this overall concern regarding the ability to generate TS revenue that is driving the Company to ask for a change in the methodology for the TSDA. The Company is prepared to continue offering an upfront credit of \$12.0 million to ratepayers, however, EGD does not believe that it should be at risk for any amount of shortfall below the \$12.0 million and is proposing to remove any threshold amount as the basis for the derivation of the TSDA.

Witnesses: J. Denomy
J. LeBlanc
D. Small

- b) Please refer to Attachment 1. The estimate for 2013 includes actual storage and transportation optimization to the end of September/13 and a forecast of \$2.8 million for the months of October 2013 to December 2013.
- c) The Company's current proposal is to continue to include a \$12.0 million credit in the determination of its allowed revenue for 2015 to 2018. The Company is also proposing that the change requested (see part a) in the treatment of the TSDA continue in years 2015 to 2018.
- d) The Company would anticipate the same treatment for 2017 and 2018.

Witnesses: J. Denomy
J. LeBlanc
D. Small

Item #		Column 1	Column 2	Column 3	Column 4
		2010 Actual \$ 000's	2011 Actual \$ 000's	2012 Actual \$ 000's	2013 - est \$ 000's
1.0	Storage Optimization	8,182.8	2,755.2	4,702.6	2,433.0
	Transportation Optimization				
2.1	- Exchange Revenue	7,734.2	12,395.4	19,926.1	24,130.4
2.2	- STS-RAM Thirdparty Exchanges	518.7	817.9	860.5	444.0
2.3	- Capacity Release Net Revenue	1,347.1	3,105.3	18,629.8	6,694.1
2.0	Transportation Optimization	9,599.9	16,318.5	39,416.5	31,268.6
3.0	Ratepayer Portion of Storage Optimization - 90 %	7,364.5	2,479.7	4,232.3	2,189.7
4.0	Ratepayer Portion of Transportation Optimization - (75% prior to 2013, 90% in 2013)	7,199.9	12,238.9	29,562.4	28,141.7
5.0	Ratepayer Portion of TS	14,564.5	14,718.6	33,794.7	30,331.4
6.0	Less Guarantee in Rates	8,000.0	8,000.0	8,000.0	12,000.0
	7.1 TSDA sub-total	6,564.5	6,718.6	25,794.7	18,331.4
	7.2 ETT Revenue - Rider H	700.0	638.4	275.4	653.4
7.0	TSDA Total	7,264.5	7,357.0	26,070.1	18,984.8
8.0	TSDA Clearance - Storage	4,019.3	1,770.3	3,505.8	1,976.8
9.0	TSDA Clearance - Transportation	3,245.1	5,586.7	22,564.2	17,008.0
	TSDA Total	7,264.5	7,357.0	26,070.1	18,984.8

BOARD STAFF INTERROGATORY #71

INTERROGATORY

ISSUE E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

Evidence Ref: D1/T5/S1; D2/T1/S1

Do the proposed depreciation rates, whether changed or not, contain an excess amount that will continue to increase the long-term liability for SRC on the corporation's balance sheet? Please explain.

RESPONSE

No.

The portion of the proposed depreciation rates that is applicable to the funding of the SRC is the amount that is considered to be the appropriate level of funding at this time.

However, it should be noted that the long-term liability for SRC on the corporation's balance sheet may increase or decrease in future years but it should not be due to any incremental excess amount as the depreciation rates as proposed include the level of funding that is considered to be appropriate at this time.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

BOARD STAFF INTERROGATORY #72

INTERROGATORY

ISSUE E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

Evidence Ref: D1/T5/S1; D2/T1/S1

Will the proposed depreciation rates recover only the underlying economic value of the related fixed assets? Please explain.

RESPONSE

The depreciation rates are structured to recover only the estimated annual consumption of service value over the rate period. The service value is defined as the original installed cost of assets adjusted for the estimated cost of removal and site restoration calculated in accordance with the CDNS method.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

BOARD STAFF INTERROGATORY #73

INTERROGATORY

ISSUE E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

Evidence Ref: D1/T5/S1; D2/T1/S1

Please discuss the choice of average service life procedure by Enbridge, versus equal life group procedure, since Gannett Fleming has stated in its depreciation study as of December 31, 2010 that "the ELG procedure provides a superior match of the consumption of service values of the assets in service to the depreciation expense". [EB-2011-0354/D2/T2/S1/Page 40]

RESPONSE

Gannett Fleming believes that the ELG procedure does provide for a superior matching of the consumption of service values of assets in service to the depreciation expense component of the revenue requirement. However, conversion to the ELG procedure will result in an increase to the depreciation rates when implemented in utilities with a mature asset base. Furthermore, the practices of the regulatory jurisdiction and practices of the utility must be considered. Utilities in Ontario and a number of other jurisdictions have had a long standing history of use of the ASL method. In the preparation of the Gannett Fleming depreciation studies as of December 31, 2010, Gannett Fleming was not aware of any specific regulatory, operational, or legislative reason to recommend a change to the ELG procedure at that time. Consistent with this long standing EGD and OEB practice, Gannett Fleming has incorporated the use of the ASL procedure in the calculation of the depreciation rates.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

FRPO INTERROGATORY #17

INTERROGATORY

ISSUE: E39. OTHER

Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

REF: D2 Tab 1 Schedule 1, page A-I-3

Please provide the basis for the cost estimate of \$1,100 for the abandonment of a service.

RESPONSE

The estimate cost of \$1,100 for the abandonment of a typical service line was developed by EGD operations staff based on the actual costs recently incurred. This amount is based on a typical installation and represents the average of recent abandonment activity.

Witnesses: L. Lawler
L. Kennedy - Garnet Fleming

FRPO INTERROGATORY #18

INTERROGATORY

ISSUE: E39. OTHER

Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

REF: D2 Tab 1 Schedule 1, page A-I-3

Given that most service abandonments occur as a result of replacement, how was the recognition of a crew on site to install the replacement service incorporated into the estimate.

RESPONSE

For service abandonment projects, costs associated with removing the retired service are recorded and tracked separately from costs relating to installing the replacement service. Construction crews on site are required to code the job type of work completed in Enbridge's work management system to distinguish between abandonment costs and new additions to Property, Plant & Equipment.

The estimate of \$1,100/service from Exhibit D2, Tab 1, Schedule 1, page A-I-3 represents only the cost of removing the abandoned service and excludes costs relating to replacement installation.

Witnesses: C. Ho
B. Yuzwa

FRPO INTERROGATORY #19

INTERROGATORY

ISSUE: E39. OTHER

Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

REF: D2 Tab 1 Schedule 1, page A-I-3

If the estimate of \$1,100 included actual costs from the past, please provide the % of steel services that contributed to the historic estimate and the percentage of steel services in active service today.

- a. If that assessment yielded such a significant unfunded liability, why has the company not presented relief for this request in this application?

RESPONSE

Discussion between Gannett Fleming and EGDI Operations staff conducted during Phase 1 of the review indicated that there is not a material difference in the costs associated in the abandonment of plastic service as compared to steel services. Therefore, Gannett Fleming did not review the split of recent activity into steel versus plastic service components.

As indicated in Schedule 1 of the Gannett Fleming report (Exhibit D2, Tab 1, page III-9), Account 473 – Services has an estimate composite remaining life of 34.7 years. Given this long remaining life, it is estimated that accumulated depreciation variances associated with the Services Account can be dealt with in accordance with the procedures as outlined in the Gannett Fleming report and do not require any specific relief as part of this study.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

SEC INTERROGATORY #120

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. II-2] Please advise whether the \$700 million fund is an actual invested fund, or a fund existing for bookkeeping purposes only. Please advise how return is recorded with respect to that fund. Please provide details of the "attention that the accumulated fund is receiving in the reviews of the Company's financial statements".

RESPONSE

The Site Restoration Liability of approximately \$859 million, is not a fund, rather it is a liability reported on EGD's financial statements. For regulatory accounting and rate making purposes, the liability amount is grouped and reported within accumulated depreciation and therefore serves to reduce the cost of capital within rates at EGD's weighted average cost of capital. The Site Restoration Liability is reviewed on a quarterly basis; the amount is calculated and reviewed each quarter, using a model that was developed by Gannett Fleming.

The "attention that the accumulated fund is receiving in the reviews of the Company's financial statements" is from management. EGDI does not have publicly listed equity securities and therefore has no analyst coverage.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Flemming

SEC INTERROGATORY #121

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. II-3] Please provide the Phase 1 report.

RESPONSE

A formal report relating to the completion and findings of Phase 1 of the Gannett Fleming assignment was not completed. A summary of the findings resulting from Phase 1 of this project was included as Appendix 1 to the filed Gannett Fleming report.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Flemming

SEC INTERROGATORY #122

INTERROGATORY

ISSUE I.E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. II-3 to II-5] Please provide numerical examples to show the differences between the various approaches discussed.

RESPONSE

Please refer to Attachment 1 for a summary of the net salvage percentages that result from each of the alternative methods discussed in the Gannett Fleming report.

While the Pause approach results in a 0% net salvage percentage for all accounts at this time, in future years it would result in higher net salvage percentages than the currently used Traditional method.

ENBRIDGE GAS DISTRIBUTION, INC.
SUMMARY OF NET SALVAGE PERCENTAGES USING THE ALTERNATIVE NET SALVAGE APPROACHES INVESTIGATED

Account	Description	Traditional Method (*)	Pause Approach	CDNS Method
451	LAND RIGHTS - INTANGIBLE	0	0	0
452	STRUCTURES AND IMPROVEMENTS	0	0	0
453	WELLS	(5)	0	(7)
454	WELL EQUIPMENT	0	0	0
455	FIELD LINES	(5)	0	(8)
456	COMPRESSOR EQUIPMENT	(5)	0	(8)
457	MEASURING AND REGULATING EQUIPMENT	(5)	0	(7)
471	LAND RIGHTS	0	0	0
472	STRUCTURES AND IMPROVEMENTS	20	0	20
473	SERVICES	(45)	0	(28)
475.1	MAINS - CAST IRON	(125)	0	(163)
475.2	MAINS-BARE STEEL	(125)	0	(115)
475.21	MAINS - COATED STEEL	(90)	0	(65)
475.3	MAINS - PLASTIC	(85)	0	(55)
476	COMPANY NGV COMPRESSOR STATIONS	0	0	0
477	MEASURING AND REGULATING EQUIPMENT	(5)	0	(7)
478	METERS	5	0	5
485	HEAVY WORK EQUIPMENT	25	0	25

(*) The net salvage percentages reflect the results of the net salvage study completed in 2011, and do not incorporate the results of the 2012 negotiated settlement process.

SEC INTERROGATORY #123

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. II-11] Please confirm that the primary problem with the traditional method is that past inflation rates are not similar to anticipated future inflation rates.

RESPONSE

Confirmed. In particular, the traditional method can be largely impacted by the very high inflationary period of the early to mid-1980's.

Witnesses: B. Yuzwa
L. Kennedy - Gannet Flemming

SEC INTERROGATORY #124

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. III-2] Please confirm that the Constant Dollar Net Salvage method requires detailed records of the vintages of existing assets.

RESPONSE

Confirmed. A file of the original installation dates of the plant in service is required

Witnesses: B. Yuzwa
L. Kennedy - Gannet Flemming

SEC INTERROGATORY #125

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. III-4] Please provide full calculations showing the derivation of the \$6.6 million.

RESPONSE

The \$6.6 million is identified by account in Schedules 2A through 2E of the Gannett Fleming Report (Exhibit D2, Tab 1, Schedule 1, pages III-10 through III-14). The amount by account is determined by dividing the variance due to CDNS (Column 5 on Schedules 2A through 2E) by the Composite Remaining Life as indicated in Column 10 of Schedule 1 of the Gannett Fleming Report (Exhibit D2, Tab 1, page III-9). Please refer to Attachment 1 for the calculations by account.

Witnesses: B. Yuzwa
L. Kennedy - Gannet Flemming

ENBRIDGE GAS DISTRIBUTION

CALCULATION OF THE ANNUAL TRUE-UP RELATED TO CDNS INCLUDED IN SCHEDULE 1

DEPRECIABLE GROUP		BOOK DEPRECIATION RESERVE 12/31/2010	CALCULATED DEPRECIATION RESERVE CDNS 12/31/2010	RESERVE VARIANCE AT 12/31/2010	VARIANCE DUE TO CDNS	COMPOSITE REMAINING LIFE	TRUE-UP INCLUDED IN TABLE 1
(1)		(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)=(5)/(6)
UNDERGROUND STORAGE PLANT							
451.10	LAND RIGHTS INTANGIBLE	20,903,515	16,085,552	4,817,963		41.9	-
452.00	STRUCTURES AND IMPROVEMENTS	4,707,662	3,317,885	1,389,777		36.5	-
453.00	WELLS	18,686,577	10,740,858	7,945,719	(200,761)	38.3	(5,242)
454.00	WELL EQUIPMENT	4,537,985	5,325,549	(787,564)		9.0	-
455.00	FIELD LINES	20,777,099	15,345,833	5,431,266	(426,275)	41.1	(10,372)
456.00	COMPRESSOR EQUIPMENT	31,054,880	30,810,807	244,073	(855,854)	27.6	(31,009)
457.00	MEASURING AND REGULATING EQUIPMENT	5,020,691	4,042,345	978,346	(75,560)	20.9	(3,615)
TOTAL UNDERGROUND STORAGE PLANT		105,688,408	85,668,829	20,019,579	(1,558,450)		(50,238)
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	1,077,659	247,042	830,617		72.5	-
472.00	STRUCTURES AND IMPROVEMENTS			-			
	VICTORIA PARK CENTRE	572,119	16,593,324	(16,021,205)		7.9	-
	KENNEDY ROAD	219,325	1,398,004	(1,178,679)		3.0	-
	OTTAWA OFFICE	1,519,771	5,613,515	(4,093,744)		14.4	-
	BROCKVILLE	42,438	138,100	(95,662)		14.6	-
	ARNPRIOR	102,517	257,902	(155,385)		14.1	-
	THOROLD OFFICE	1,373,703	4,035,857	(2,662,154)		19.0	-
	EASTERN	212,254	737,401	(525,147)		9.7	-
	KELFIELD	68,117	370,163	(302,046)		9.9	-
	OTTAWA DEPOT	313,477	1,388,308	(1,074,831)		9.9	-
	OTHER	835,027	1,966,614	(1,131,587)		32.3	-
TOTAL STRUCTURES AND IMROVEMENTS		5,258,748	32,499,188	(27,240,440)	-	10.3	-
473.00	SERVICES	869,945,320	641,743,313	228,202,007	110,101,522	34.7	3,172,955
475.10	MAINS - CAST IRON	-9,973,664	12,791,324	(22,764,988)	(1,755,741)	4.4	(399,032)
475.20	MAINS - BARE STEEL	9,031,401	13,154,853	(4,123,452)	611,853	5.4	113,306
475.21	MAINS - COATED STEEL	464,144,414	494,167,949	(30,023,535)	74,873,927	42.5	1,761,739
475.30	MAINS - PLASTIC	463,148,188	332,098,688	131,049,500	109,684,735	55.3	1,983,449
475.EN	MAINS - ENVISION	19,041,660	19,756,593	(714,933)		21.0	-
476.00	COMPANY NGV COMPRESSOR STATIONS	1,605,736	1,585,128	20,608		6.4	-
477.00	MEASURING AND REGULATING EQUIPMENT	159,007,375	92,658,512	66,348,863	890,951	25.5	34,939
478.00	METERS	92,616,048	166,232,283	(73,616,235)		7.6	-
TOTAL DISTRIBUTION PLANT		2,074,902,884	1,806,934,873	267,968,011	294,407,247		6,667,356
GENERAL PLANT							
483.01	OFFICE EQUIPMENT	2,894,801	1,983,518	911,283		10.9	
483.02	FURNISHINGS	6,067,053	8,271,686	(2,204,633)		5.6	
484.00	TRANSPORTATOIN EQUIPMENT	7,841,000	11,409,970	(3,568,970)		7.7	
484.01	TRANSPORTATION - COMPANY NGV KITS	4,607,319	4,241,878	365,441		4.5	
484.02	TRANSPORTATION - COMPANY NGV CYLINDERS	787,083	755,156	31,927		2.6	
485.00	HEAVY WORK EQUIPMENT	6,829,160	5,247,763	1,581,397		11.0	
486.00	TOOLS AND WORK EQUIPMENT	13,117,640	13,409,526	(291,886)		15.1	
487.70	RENTAL - VRA'S	964,239	837,157	127,082		6.9	
487.80	RENTAL - NGV STATION	3,100,277	3,912,367	(812,090)		4.5	
487.90	RENTAL - NGV CYLINDERS	705,489	912,461	(206,972)		2.7	
488.00	COMMUNICATION EQUIPMENT	2,122,651	2,107,849	14,802		3.0	
TOTAL GENERAL PLANT		49,036,712	53,089,331	(4,052,619)	-		-
COMPUTER AND SOFTWARE							
490.00	COMPUTER EQUIPMENT	4,351,484	13,741,626	(9,390,142)		2.4	
491.01	SOFTWARE - ACQUIRED	24,804,515	32,991,705	(8,187,190)		1.9	
491.02	SOFTWARE - DEVELOPED	19,179,561	20,616,303	(1,436,742)		2.5	
491.03	CIS SOFTWARE ACQUIRED	15,741,236	19,064,721	(3,323,485)		8.5	
TOTAL COMPUTER AND SOFTWARE		64,076,795	86,414,355	(22,337,560)	-		-
		2,293,704,799	2,032,107,388	261,597,411	292,848,797		6,617,118

SEC INTERROGATORY #126

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. III-6] Please confirm that the transition plan is not independent expert advice provided by Gannett Fleming, but is instead an acceptance by Gannett Fleming of a plan developed by Enbridge.

RESPONSE

Enbridge confirms that the transition plan, or the pattern of clearance of the Site Restoration Amounts was an approach proposed by Enbridge and accepted by Gannett Fleming.

As indicated in evidence found at Exhibit D1, Tab 5, Schedule 1, page 4 of 15, Paragraph 10, the Company requested that additional studies should be completed to determine whether the Company's current approach to SRC requirement was appropriate. Gannett Fleming was commissioned by Enbridge to conduct an SRC or Net Salvage study to determine the appropriateness of the current liability on the balance sheet, and to assess whether different methods could be used to calculate ongoing SRC requirements.

As indicated later in that same exhibit at page 6 of 15, Paragraph 16, Gannett Fleming, stated that a Constant Dollar Net Salvage ("CDNS"), approach to the calculation of the net salvage percentages is an appropriate approach to more accurately reflect the future requirement of amounts Enbridge should accrue for SRC.

SEC INTERROGATORY #127

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. III-7] Please reconcile the declining repayments with the pattern of rate increases in the Application before these repayments.

RESPONSE

As indicated in the referenced evidence, and further in the CDNSADA evidence at Exhibit D1, Tab 8, Schedule 3, the Company and Gannett Fleming consulted in the determination of the annual amount of adjustment and rate rider credit.

The Company respectfully submits that there is no specific reconciliation that can be performed as requested. In the determination of the proposed five year pattern of rate rider credits, the following issues were considered but not necessarily in any particular order or by interpreted measure of importance;

- A pattern which would credit ratepayers as much as possible in earlier years while giving consideration to annual bill impact changes from any such pattern
- Consideration of how credits could be patterned to achieve some level of "offset" when viewed against annual rate increases
- A pattern which would achieve a minimal 2019 re-basing year bill increase impact subsequent to the conclusion of the bill credits in 2018

While EGD submits that there is no perfect view as to how the amounts in question should be credited to ratepayers, it believes all of these issues are necessary considerations which have informed the development of the proposed annual rate rider credits.

Witnesses: K. Culbert
B. Yuzwa

SEC INTERROGATORY #128

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. III-8] Please advise whether Gannett Fleming is claiming expertise related to rate shock and inter-generational equity.

RESPONSE

Gannett Fleming (Mr. Kennedy) is claiming expertise in depreciation and costs of removal and all calculations associated with each. Specifically, Mr. Kennedy is claiming expertise on the impact upon the depreciation expense inclusion in revenue requirement and the generational equity of the various depreciation and net salvage procedures.

Witnesses: B. Yuzwa
L. Kennedy - Gannet Flemming

SEC INTERROGATORY #129

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D2/1/1, p. A-I-4] Please provide Gannett Fleming's professional opinion whether the current distribution Services account is too high, too low, or the appropriate amount.

RESPONSE

The conclusions stated in the summary of results from the Phase 1 review were made prior to the further detailed analysis as completed in Phase 2 of the Gannett Fleming assignment. Based on the results from Phase 2, Gannett Fleming is recommending a reduction in the net salvage percentage from -45% to a CDNS developed -28%. As such, Gannett Fleming would view the current net salvage percentage of -45% to be more negative than required.

Witnesses: B. Yuzwa
L. Kennedy - Gannet Flemming

SEC INTERROGATORY #130

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D1/5/1, p. 4] Please confirm that the review of SRC was initiated by Enbridge.

RESPONSE

Confirmed.

Witness: B. Yuzwa

SEC INTERROGATORY #131

INTERROGATORY

Issue E39: Are the proposed depreciation rate changes, to be in use beginning in the 2014 Fiscal Year, related to a reduction in the annual level of Site Restoration Cost/Asset Retirement Obligation ("SRC/ARO") collected, appropriate?

- a. Is Enbridge's proposal to continue with all other depreciation rates established in the EB-2011-0354 proceeding, throughout the IR period appropriate?

[D1/5/1, p. 10] Please confirm that the Applicant may seek, at the time of the next rebasing, to increase the provision for SRC/ARO, including potentially catching up excess repayments to ratepayers during the IRM period.

RESPONSE

Enbridge is not in a position to confirm or deny whether there will be an increase, decrease or maintenance of the current levels of provision for SRC at the end of next rebasing period. As part its 2019 re-basing application, Enbridge is committed to conduct another Net Salvage Study in 2018, the outcome of which will assist in determining changes, if any, related to the provision of SRC.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #74

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref: EGDI's audited financial statements for 2009 through 2012

Enbridge's audited financial statements for 2009 through 2012 contain the following end of year long-term liabilities for the SRC. This liability information was obtained from Enbridge's financial statements filed in its prior applications in financial statement notes that disclose the effects of rate regulation. These financial statements also indicate that the disclosure is under other long term liabilities.

<u>Audited Financial Statements</u>	<u>Line</u>		<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>
Beginning of year liability	1		0.0	691.6	753.0	815.0
Period-to-date adjustment	2		640.0			
Recovery through depreciation	3	+				
Site restoration and removal costs	4	(-)				
Net change in year	5	3+4	51.6	61.4	62.0	44.0
End of year liability	6	1+2+5	691.6	753.0	815.0	859.0

Board staff has provided an Excel workbook to facilitate the calculations. Please complete the table above and provide the amounts recovered through depreciation each year and the amounts deducted or paid for site restoration and removal costs actually completed.

Witnesses: C. Ho
B. Yuzwa

RESPONSE

Please refer to Enbridge's response to Board Staff Interrogatory #77 at Exhibit I.E40.EGDI.STAFF.77.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #75

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref: EGDI's audited financial statements for 2009 through 2012

Please provide the engineering studies that were completed in order to calculate the liability of \$691.6 million at the end of 2009.

RESPONSE

In 2009, Enbridge engaged Gannett Fleming, Inc. (Gannett), a depreciation consultant, to develop a model to calculate the negative salvage component of Property, Plant & Equipment. Please see Attachment #1 for the letter issued by Gannett on the methodology and assumptions used in the model.

Enbridge used the model to determine the liability at the end of 2009. Please see Attachment #2 which is the calculation for the liability balance of \$691.6 million.



GANNETT FLEMING, INC.
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December 15, 2009

Enbridge Gas Distribution Inc.
ATTN: Tara Knight
PO Box 650
Scarborough, Ontario
M1K 5E3

Dear Ms. Knight:

Allocation of September 30, 2009 Accumulated Depreciation Balance

I have attached an allocation of the Enbridge Gas Distribution ("EGD") September 30, 2009 Accumulated Depreciation balances into the portions relating to the provision for future Site Restoration and Abandonment and the provision relating to the recovery of the original cost of investment. Gannett Fleming, Inc. ("Gannett Fleming") has prepared similar allocations on behalf of a number of regulated Canadian utilities over the past few years. To my knowledge this allocation has been considered reasonable for both financial disclosure and rate regulation purposes. The methods and procedures used in the attached allocation of your September 30, 2009 Accumulated Depreciation balances is consistent with the methods and procedures used in all previous allocations prepared by Gannett Fleming to Canadian clients, and will provide a basis for the allocation of December 31, 2009 Accumulated Depreciation balances.

In the development of the allocation of the Accumulated Depreciation balances the following steps were undertaken:

- Update of the net salvage components from those currently used and approved by the Ontario Energy Board for inclusion in your Depreciation Rate Calculations. The currently approved net salvage provision results from the calculations as prepared by Gannett Fleming in a report to the Ontario Energy Board titled "Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of September 30, 2001"

("the 2002 study"). I understand that the depreciation rates used for GAAP purposes have remained the same as those developed in the 2002 study. The updated analysis for net salvage included the review of the 2003 through 2008 net salvage transactions in addition to the transactions that were considered in the analysis related to the 2002 depreciation study.

- The results of the net salvage study were analyzed to determine if changes to the net salvage parameters would be warranted for the allocation of the September 30, 2008 accumulated depreciation balances.
- Development of a model specific to EGD to incorporate the costs of removal for the purposes of allocating the September 30, 2009 Accumulated Depreciation balances.

The model developed by Gannett Fleming incorporates the following significant assumptions:

- The component of cost of removal from the updated net salvage study has been assumed to be in place since the time of the original installations of the current plant in service. EGD calculates the depreciation in accordance with the "Remaining Life Basis" which will true-up the accumulated depreciation account to be in accordance with the depreciation parameters from the net salvage study. Therefore this assumption is considered reasonable by Gannett Fleming and has been used in a number of allocations of Accumulated Depreciation by Gannett Fleming throughout Canada.
- The conceptual basis of the allocation model that was prepared by Gannett Fleming for the allocation of the December 31, 2008 accumulated depreciation balances continues to be reasonable.

The attached allocation of accumulated depreciation results from an application of methods and procedures that Gannett Fleming has used on a number of occasions for clients throughout Canada. These procedures have been used for both regulatory and financial disclosure purposes, and to my knowledge have been accepted to provide a reasonable estimate of the funds that have been collected for future costs of removal. The application of these accepted methods and procedures for EGD provides for a reasonable estimate for the provision for costs of removal.

Ms. Tara Knight
Enbridge Gas Distribution

If you have any questions on the attached allocations please feel free to call me and discuss.

Sincerely,

GANNETT FLEMING, INC.
Valuation and Rates Division

A handwritten signature in black ink, appearing to read 'L. Kennedy', with a stylized flourish at the end.

Larry E. Kennedy
Director, Canadian Services

ENBRIDGE GAS DISTRIBUTION
Allocation of the Accumulated Depreciation Account into the Life and cost of Removal Components
As at December 31, 2009

Account	Description	Gross Salvage Cost of Removal		Net Salvage	As at September 30, 2009			As at December 31, 2009		
		Percentage	Percentage		Total Accumulated Depreciation	Portion of Actual AD Applicable to Life	Portion of Actual AD Applicable to COR	Total Accumulated Depreciation	Portion of Actual AD Applicable to Life	Portion of Actual AD Applicable to COR
472	Structures and Improvements	7	-10	0	4,593,946	4,593,946	-	5,112,945.90	5,112,945.90	-
473.1	Services	0	-46	-40	807,216,551	576,583,251	230,633,300	821,273,545.22	596,623,960.87	234,649,584.35
475.1	Mains - Plastic		-100	-100	396,921,302	198,460,651	198,460,651	409,181,327.47	204,590,663.74	204,590,663.74
475.2	Mains - Cast Iron		-100	-100	5,158,246	2,579,123	2,579,123	6,785,479.15	3,392,739.58	3,392,739.58
475.3	Mains - Other		-100	-100	8,759,877	4,379,939	4,379,939	8,813,916.67	4,406,958.34	4,406,958.34
475.4	Mains - Coated Steel		-100	-100	422,922,807	211,461,404	211,461,404	430,318,608.15	215,159,304.08	215,159,304.08
475	Mains - Envision		-100	-100	13,259,898	6,629,949	6,629,949	14,354,379.01	7,177,189.51	7,177,189.51
476	Company NGV Compressor Stations	0	0	0	1,402,141	1,402,141	-	1,443,695.29	1,443,695.29	-
477	Measuring and Regulating Equipment		-25	-25	141,083,923	112,867,138	28,216,785	144,859,044.60	115,887,235.68	28,971,808.92
478	Meters	0	0	0	95,094,019	95,094,019	-	95,863,314.59	95,863,314.59	-
483.1	Office Furniture and Equipment - Equip	0	0	0	3,676,889	3,676,889	-	3,692,766.79	3,692,766.79	-
483.2	Office Furniture and Equipment - Furniture	0	0	0	8,169,414	8,169,414	-	8,391,699.30	8,391,699.30	-
484	Transportation Equipment	12	0	15	8,050,632	8,050,632	-	7,556,206.42	7,556,206.42	-
484.1	Transportation Equipment - NGV Kits	3	0	10	4,418,180	4,418,180	-	4,446,527.44	4,446,527.44	-
484.2	Transportation Equipment - NGV Cylinders	10	0	10	748,454	748,454	-	756,169.07	756,169.07	-
485	Heavy Work Equipment	26	0	25	6,695,996	6,695,996	-	6,775,986.17	6,775,986.17	-
485.1	Tractor Equipment	0	0	0	12,358,824	12,358,824	-	12,463,618.84	12,463,618.84	-
487.73	Tractor Equipment - Retail	0	0	0	908,939	908,939	-	919,971.33	919,971.33	-
487.8	Rental Equipment - NGV Stations	0	0	0	4,860,889	4,860,889	-	4,985,334.49	4,985,334.49	-
487.93	Rental Equipment - Communication	0	0	0	639,525	639,525	-	652,136.30	652,136.30	-
488	Communication Equipment	0	0	0	2,050,991	2,050,991	-	2,065,126.39	2,065,126.39	-
489	Sim Application	0	0	0	1	1	-	-	-	-
490	Computer Equipment	0	0	0	61,108,656	61,108,656	-	58,616,261.01	58,616,261.01	-
					1,999,943,786	1,322,740,882	677,202,904	2,035,779,705	1,344,216,036	691,562,769
										\$ 31,09

Net Site Restoration Costs - Dec

BOARD STAFF INTERROGATORY #76

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref: EGDI's audited financial statements for 2009 through 2012

Please provide the accounting policy documents that explain how Enbridge's accounting staff validated, estimated and recorded the opening liability and the changes in the liability during each year 2009-2012. If any of the accounting journal entries relies on budgeted burden rates, etc., please provide all of the calculations that support the additions and deductions to the liability each year. Please explain how the numbers were determined.

RESPONSE

In 2009, Enbridge engaged Gannett Fleming, Inc. (Gannett), a depreciation consultant, to develop a model to calculate the negative salvage component of Property, Plant & Equipment. The model was an allocation of Enbridge's accumulated depreciation balances into the portions relating to the provision for future site restoration and abandonment costs and the provision relating to the recovery of the original cost of investment. Enbridge verified the calculations performed by Gannett for reasonability and accuracy and recorded the opening balance of the liability based on the model as of September 30, 2009. The journal entry recorded was to reclassify the provision for future site restoration costs from accumulated depreciation to a long-term liability.

During the period 2009 to 2012, as actual site restoration and removal costs were incurred, they were recorded in accumulated depreciation. Enbridge used the same model developed by Gannett to determine the balance of the liability on a quarterly basis and recorded journal entries to adjust for the change in the liability accordingly.

None of the journal entries relied on budgeted information. The fluctuation in the balance of the liability was driven by the change in the accumulated depreciation balances, which were impacted by actual site restoration costs incurred, depreciation expense recorded, and costs of assets retired.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #77

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please complete the following table to project the SRC long-term liability as at December 31, 2018 for EGDI if its proposals as filed in this application to change depreciation rates are accepted. Board staff has provided an Excel workbook to facilitate the calculations.

<u>EGDI Utility Only</u>	Line		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beginning of year liability	1		0.0	691.6	753.0	815.0	859.0	859.0	859.0	859.0	859.0	859.0
Period-to-date adjustment	2		640.0									
Recovery through depreciation	3	+										
Site restoration and removal costs	4	(-)										
Net change in year	5	3+4	51.6	61.4	62.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0
End of year liability	6	1+2+5	691.6	753.0	815.0	859.0	859.0	859.0	859.0	859.0	859.0	859.0

RESPONSE

Please refer to Attachment 1 for a schedule on the long term liability balance for years 2009 to 2018.

Witnesses: C. Ho
B. Yuzwa

Enbridge used a model developed by Gannett Fleming, Inc. (Gannett) to determine the liability for future site restoration costs. The model was based on estimated negative salvage component of Property, Plant & Equipment applied to the accumulated depreciation balances associated to the assets.

As actual site restoration and removal costs were incurred, they were recorded in accumulated depreciation. Since the liability was determined based on estimated net salvages, differences between actual removal costs based on assets retired and estimated costs in the model would have an impact on the overall liability balance.

Therefore, the fluctuation in the balance of the liability was driven by depreciation expense, actual site restoration costs incurred, and the variance between actual and estimated removal costs based on costs of assets retired.

Witnesses: C. Ho
B. Yuzwa

Enbridge
EB-2012-0459
Future Removal and Site
Restoration Reserves or
Liability

EGDI Utility Only	Line	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beginning of year liability	1	0.0	691.6	753.0	815.0	859.0	903.9	862.0	828.0	806.2	791.7
Period-to-date adjustment	2	640.0									
Recovery through depreciation	3	+	74.8	79.4	82.4	87.4	63.2	42.1	44.9	51.1	53.5
Actual site restoration and removal costs	4	(-)	(22.4)	(18.7)	(34.2)	(27.7)	(18.3)	(15.9)	(15.8)	(14.9)	(14.9)
Actual removal costs vs. estimated salvage requirement	5	+ / (-)	(0.9)	0.7	13.8	(15.6)	-	-	-	-	-
Return to ratepayers	6	(-)	-	-	-	-	(68.1)	(63.1)	(58.1)	(53.1)	(17.4)
Net change in year	7	3+4+5+6	51.6	61.4	62.0	44.0	44.9	(41.9)	(33.9)	(21.9)	(14.5)
End of year liability	8	1+2+7	691.6	753.0	815.0	859.0	903.9	862.0	806.2	791.7	815.1

Note 1: Variance was mainly driven by costs incurred from retirement of cast iron mains exceeding estimated salvage per Gannett Fleming's model.

Note 2: Variance was mainly driven by costs incurred from retirement of bare steel mains being lower than estimated salvage per Gannett Fleming's model.

BOARD STAFF INTERROGATORY #78

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please explain how Enbridge created the long-term liability in 2009 for SRC? Did Enbridge reduce accumulated depreciation in order to create the SRC liability?

RESPONSE

Please refer to Enbridge's response to Board Staff Interrogatory #76 at Exhibit I.E40.EGDI.STAFF.76.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #79

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

The CICA issued *AcG-19 Disclosures by Entities Subject to Rate Regulation* in May 2005. What changes in accounting standards in 2008 or 2009 required Enbridge to reclassify a portion of accumulated depreciation to long term liabilities?

RESPONSE

Prior to 2009, paragraph 34 of Section 1100 *Generally Accepted Accounting Principles* of the CICA Handbook provided an exemption to the application of Section 1100 for rate-regulated entities, stating that "...an entity is not required to apply this Section to the recognition and measurement of assets and liabilities arising from rate regulation..."

Effective January 1, 2009, the exemption in paragraph 1100.34 was removed from the CICA Handbook. In the absence of specific guidance on how to account for amounts collected from customers for future site removal and restoration, Enbridge consulted U.S. GAAP, specifically Statement of Financial Accounting Standards No. 143 *Accounting for Asset Retirement Obligations* ("FAS 143") for guidance, as permitted by paragraph 1100.24 of the CICA Handbook.

Paragraphs 19 and 20 of FAS 143 required amounts collected from customers for future removal and site restoration to be reported as a regulatory liability, instead of within Property, Plant and Equipment. Consequently, Enbridge reclassified such amounts, which were previously recorded in accumulated depreciation, to a long-term regulatory liability in 2009.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #80

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please provide the applicable accounting standard(s) followed by Enbridge before the changes in 2008 or 2009 that relate to SRC, accumulated depreciation and entities subject to rate regulation.

RESPONSE

Please see the response to Board Staff Interrogatory #79 found at Exhibit I.E40.EGDI.STAFF.79.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #81

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please provide the accounting standard(s) that caused Enbridge to change its financial statement disclosure of accumulated depreciation and long-term liabilities related to SRC in 2009. Please identify the applicable paragraphs in the standard(s) and discuss why Enbridge interpreted the standard to require the reduction of accumulated depreciation and the creation of the long-term liability. Please explain fully why Enbridge had to reduce accumulated depreciation and create the long-term liability for SRC in its balance sheet.

RESPONSE

Please see the response Board Staff Interrogatory #79 found at Exhibit I.E40.EGDI.STAFF.79.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #82

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Did Enbridge's original plans for adopting IFRS cause Enbridge to change its accounting policy to reduce accumulated depreciation and to increase the long-term liability in 2009? Please explain.

RESPONSE

Enbridge did not adopt IFRS. Hence, there were no changes in its accounting policies related to IFRS.

Please see the response to Board Staff Interrogatory #79 found at Exhibit I.E40.EGDI.STAFF.79.

Witnesses: L. Au
B. Yuzwa

BOARD STAFF INTERROGATORY #83

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Enbridge quoted the USoA definition of depreciation in EB-2011-0254 at evidence reference Exh.D1/Tab5/Sch.1/Page2

"5. The methodology used by Gannett Fleming in estimating average service lives and salvage is identical to the previous studies and the methodology adopted by the other major gas company in Ontario. This study conforms with the directive in the Ontario Energy Board's "Uniform System of Accounts For Class 'A' Gas Utilities" dated April 1, 1996 (p. 116, para. F).

Depreciation rates shall be based on the estimated service values and estimated service lives of the plant developed by a study of the utility's history and experience and such engineering and other information as may be available with respect to future conditions. Non-depreciable plant should not be included in calculating rates or applying them.

The rates, when filed, shall be accompanied by a statement showing the bases for the rates and the methods employed in their computation, and shall be developed by the utility by the method deemed most appropriate in the light of the utility's retirement experience."

Please explain how this description supports collecting more through depreciation than required which permitted Enbridge to calculate an amount of \$859.0 million payable to its ratepayers as at December 31, 2012.

RESPONSE

The amount of \$859 million, shown in EGDs financial statements as at December 31, 2012, does not represent a payable amount to ratepayers. The liability amount represents the residual or reserve amount of estimated future removal and site restoration costs to be incurred by EGD which have previously been recovered through rates.

Witnesses: K. Culbert
B. Yuzwa

BOARD STAFF INTERROGATORY #84

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

In EGD's 2012 audited financial statements the following description of the SRC liability can be found. EB-2013-0046/Exhibit D/Tab 1/Schedule 1/Page 18 of 41

"9. Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected." *[Emphasis added.]*

In which decision did the Board first approve collecting excess depreciation to fund future costs for removal and site restoration relating to property, plant and equipment? Please provide copies of the relevant sections of the decision(s).

RESPONSE

As indicated within the Gannett Fleming Net Salvage Study evidence at Exhibit D2, Tab 1, Schedule 1, net salvage percentages derived through the study, are intended to recover within depreciation rates, estimates of ongoing and future removal and site restoration costs. The recovery of such net salvage percentages and resulting estimated costs does not result in the collection of or approval by the Board of excess depreciation.

The Company has collected amounts in depreciation costs to fund future costs for removal and site restoration since at least 1959.

Witnesses: K. Culbert
B. Yuzwa

As indicated in evidence filed for the Company's 1997 Test Year and found at Exhibit B2, Tab 6, Schedule 1 of EBRO 492, filed herein as Attachment 1, the depreciation study filed in that proceeding was based on "... methodology used in estimating average services and salvage (that was) identical to the previous studies and to the methodology adopted by the other major gas companies in Ontario".

The study under review in that 1997 Test Year proceeding was referred to as the sixth depreciation study undertaken by Consumers Gas since converting to natural gas in 1955. It was based on a review of 1994 actual asset values and made reference to previous studies dated 1959, 1972, 1980, 1987 and 1991. As noted, those previous studies estimated both service lives and salvage.

The Board Decision With Reasons in the EBRO 492 proceeding, dated September 10, 1996, accepted the Depreciation Study with (1) the acceptance of a settlement proposal related to Computer assets, and (2) an exception to the proposed change in the treatment of Base Pressure gas.

Witnesses: K. Culbert
B. Yuzwa

1997 TEST YEAR

EBRO 492
Exhibit B2
Tab 6
Schedule 1
Page 1 of 33

RECOMMENDATIONS

IN SUMMARY

This is the sixth depreciation study undertaken by Consumers Gas since converting to natural gas in 1955. The first two studies, in 1959 and 1972 were done by Stone and Webster Management Consultants, Inc. The 1980, 1987, 1991 and the present study have been done with in-house expertise. The methodology used in estimating average service lives and salvage is identical to the previous studies and to the methodology adopted by the other major gas companies in Ontario.

This study conforms with the directive in the OEB's Uniform System of Accounts for Gas Utilities which says that depreciation rates

"...shall be based on estimated service values and estimated service lives of the plant developed by a study of the Company's history and experience and such engineering and other information as may be available with respect to future conditions." (p. 12, para. F)

The following pages will explain the reasons for recommending an increase of the composite depreciation rate from 3.9% to 4.5%.



Consumers Gas

DECISION WITH REASONS

E.B.R.O. 492

IN THE MATTER OF the Ontario Energy Board Act, R.S.O.
1990, c. O.13;

AND IN THE MATTER OF an Application by The
Consumers' Gas Company Ltd. for an order or orders approving
rates to be charged for the sale, distribution, transmission and
storage of gas for its 1997 fiscal year.

BEFORE: P. Vlahos *
Presiding Member

E.J. Robertson
Member

H. G. Morrison
Member

- * Mr. Vlahos stood down from the E.B.R.O. 492 proceeding effective June 4, 1996. Mr. Robertson presided thereafter.

DECISION WITH REASONS

September 10, 1996

DECISION WITH REASONS

2.3 DEPRECIATION STUDY

- 2.3.1 The new depreciation study prepared by Stone and Webster proposed to increase the composite depreciation rate from 3.9 percent to 4.5 percent. The largest influences are the increases to the depreciation rates for distribution plant services and mains and the increase to the depreciation rate for computer equipment. The Company also proposed to depreciate unrecoverable base pressure gas.

Computer Equipment

- 2.3.2 The Company stated that a review of the composition of its computer equipment account indicated that approximately 50 percent of the account was comprised of hardware which will be predominately driven by the acquisition of personal computers in the next few years, while the remainder of the account includes software, infrastructure costs and other equipment including LANs, printers, and modems. The Information Systems department for Consumers Gas estimated that personal computers would not have an economic life exceeding three years, while the remaining items in the account would be economically useful over five years. The Company consequently proposed a composite average service life of four years for the whole account, which is two years shorter than the current average service life of six years.

Base Pressure Gas

- 2.3.3 The Company currently includes the actual costs of acquiring base pressure gas in rate base, and earns a return on the capital invested in that asset. Intergenerational equity is maintained since customers will pay for the use of base pressure gas no matter when the customer attaches to the system.
- 2.3.4 In response to a directive in the E.B.R.O. 487 Decision With Reasons, the Company filed a proposal to depreciate the portion of base pressure gas that is not likely to be recoverable. The Company proposed using a Broad Group procedure with depreciation calculated using the straight line method on a remaining life basis. Specifically, the Company calculated a depreciation rate by applying an after tax salvage ratio to the entire account balance, and dividing the amount by

DECISION WITH REASONS

the estimated average service life of the Broad Group. As the Company does not maintain records of additions and retirements, the estimated remaining life of 36.1 years from the land rights account analysis was used as a proxy.

- 2.3.5 In calculating the salvage ratio the Company first determined the amount of gas that could be economically recovered, and the cost of that recovery. The Company used the historic average unit cost to value the recoverable volumes, and then subtracted the recovery costs to produce a salvage factor of 58 percent. The Company reduced the salvage ratio to 33 percent in order to attribute to customers benefitting from the asset throughout its useful life the future taxes payable on the proceeds of disposition in excess of the fully depreciated value for tax purposes.
- 2.3.6 Board Staff witness Dr. Mark S. Gerber criticized the Company's proposal as being inconsistent with the National Association of Regulatory Utility Commissioners ("NARUC") definition of depreciation since base pressure gas does not meet any of the nine causes of lost value cited in the definition. Dr. Gerber also noted that the Company's proposal to value recoverable gas at average historical cost was "going against the accepted practice concerning salvage value" as defined in the NARUC system of accounts as "the amount received from property retirement ..." (emphasis added).
- 2.3.7 Dr. Gerber felt the proposal increased intergenerational inequity, over-recovered the value of unrecoverable gas and inappropriately included a tax adjustment to the estimated salvage value.
- 2.3.8 As an alternative, Dr. Gerber proposed to simply depreciate the unrecoverable portion of base pressure gas, while retaining the remaining base pressure gas in rate base at its average historical value. While this proposal eliminates issues surrounding salvage value and reduces intergenerational inequities, Dr. Gerber pointed out that the alternative method still requires an estimate of unrecoverable volumes which varies with technology and market conditions.

DECISION WITH REASONS

Positions of the Parties

- 2.3.9 Board Staff, CAC, Direct Energy, ECNG, Energy Probe, IGUA, and OCAP participated in the ADR discussion of this issue. The ADR Agreement stated that all of these parties accepted the Company's proposals, except for the depreciation rate for computer equipment, and the proposal to depreciate base pressure gas. All the above parties agreed that the expected life of personal computers is shortening and is shorter than that suggested by historical analysis, but that there is not conclusive evidence with respect to the precise expected life. As a result, personal computers should be depreciated over a four year life, resulting in an estimated life for the entire Computer Equipment account of four and a half years rather than the proposed four years as set out in the Company's pre-filed evidence. There was no agreement on the depreciation of Base Pressure Gas.

Board Findings

- 2.3.10 With the exception of the proposed change in the treatment of base pressure gas, the Board accepts the Company's proposed depreciation study, as adjusted for the impact of the ADR Agreement on the depreciation of computer equipment.
- 2.3.11 With regards to base pressure gas, the Board agrees with Dr. Gerber's criticisms of the Company's proposal. The Board is of the view that Dr. Gerber's proposal for depreciating the unrecoverable portion of base pressure gas is simpler and less subjective than the Company's proposal.
- 2.3.12 However, since the Company is a going concern and the use of storage and associated base pressure gas are integral to the Company's core business, the Board can see no particular advantage to depreciating the unrecoverable portion of base pressure gas. The Board is of the view that the simplicity and intergenerational fairness inherent in the current practice is the superior approach. The Board therefore finds that no depreciation shall be taken on base pressure gas. As a result, the depreciation expense allowance has been reduced by \$0.5 million as outlined in Appendix A, and accumulated depreciation has been reduced by \$0.3 million as outlined in Appendix B.

BOARD STAFF INTERROGATORY #85

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

How does Enbridge determine which portion of project costs relates to SRC and which costs relate to new additions to PP&E?

RESPONSE

When project costs are incurred, site restoration and abandonment costs are recorded and tracked separately from costs relating to new additions in a different general ledger account in PP&E. Costs relating to new additions are capitalized to the cost base of various assets in PP&E while SRC are recorded to the accumulated depreciation balances associated to the assets.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #86

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please provide the engineering studies and/or policies that provide the guidance to construction crews regarding SRC and new construction, whether these crews are Enbridge's staff or contract staff.

RESPONSE

When project costs are incurred, site restoration and abandonment costs are recorded and tracked separately from costs relating to new construction in a different general ledger account in PP&E. All construction crews, whether they are Enbridge's employees or contractors, are required to code the job type of work completed in the system to distinguish between new additions and SRC.

Costs relating to new additions are capitalized to the cost base of various assets in PP&E while SRC are recorded to the accumulated depreciation balances associated to the assets.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #87

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Please provide the accounting policies that describe what work Enbridge's accounting staff must do in order to record the amounts to the SRC liability account and to PP&E.

RESPONSE

Please refer to Enbridge's response to Board Staff Interrogatory #76 at Exhibit I.E40.EGDI.STAFF.76.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #88

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

Is there a reason why Enbridge should not refund the full amount of \$859.0 million to ratepayers rather than the \$269.0 million proposed? Should interest apply to the balance to be refunded? Why or why not?

RESPONSE

The SRC reserve on EGD's financial statements should reflect the age of assets in service in order that the SRC reserve is aligned with the consumed service value of the current assets in service. As such, the concept is that the users of the EGD system at any point in time are responsible for the consumption of the service value of the assets (including the anticipated costs of removal and site restoration) related to the assets available for use at that same point in time. Gannett Fleming has determined that as at December 31, 2010, the SRC reserve was over-funded by \$292.8 based on a calculation incorporating the use of the CDNS method and recognizing the age of assets in service, leaving a required SRC fund of \$566 million. As such, after the refund of the \$269 million combined with the accumulated depreciation true-up, the fund will be aligned with the consumed service value of the EGD assets.

If EGD was to refund the entire SRC reserve of \$859 million, there would be no reserve related to the assets in service, notwithstanding that the current asset base has been in service for a number of years, and has a depreciated service value. In this circumstance, historic toll-payers would have funded within their historic tolls the current balance of \$859 million and current toll-payers, over the next five-year period, would be the beneficiaries of a free-ride (with regard to the funding of the future removal of assets that they are currently using). Current toll-payers would also receive a tolling reduction of the funds paid by users to the direct account of the future users of the system who will be

Witnesses: K. Culbert
B. Yuzwa

responsible for 100% of the SRC costs of the assets for which they will only consume a fraction of the service value.

With regard to a consideration of interest being applicable to any amount of over-funding of the SRC fund, it is noted that the accumulated depreciation account has been increased by the amount of the SRC balance. As such the Company's rate base has been reduced and the revenue requirement has been reduced by the allowed rate of return on rate base applicable to any over-funding.

Witnesses: K. Culbert
B. Yuzwa

BOARD STAFF INTERROGATORY #89

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1

What has Enbridge done with the \$859.0 million recovered from ratepayers many years in advance of the need for the funds? Please explain fully.

RESPONSE

The expense collected in rates relates to depreciation. The portion thereof that led to the \$859.0 million Site Restoration Liability (pursuant to a depreciation study conducted by an independent third party – Gannett Fleming and approved by the Ontario Energy Board) has been used in the normal course of the Company's operational activities. This liability amount has had the effect of reducing rate base over the period and has provided lower revenue requirements as a result.

Witnesses: L. Au
B. Yuzwa

BOARD STAFF INTERROGATORY #90

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

In the Net Salvage Study D2/T1/S1/Page II-2 the following information appears.
"Based on the impacts that the large annual requirement for net salvage is causing in the company's revenue requirement (over \$50 Million annually), and on the attention that the accumulated fund is receiving in reviews of the company's financial statements, Enbridge asked Gannett Fleming to review the assumptions and concepts used in the net salvage calculations and to determine if, in fact, the actual requirements are as large as the depreciation studies have been indicating."

- a) What type of attention has Enbridge received in reviews of the company's financial statements?
- b) What are the external analysts' concerns?
- c) Please file on the record two or three of the analysts' reviews of EGD's financial statements.

RESPONSE

- a) The attention the accumulated fund is receiving is from Enbridge Gas Distribution ("EGD") management. EGD does not have equity securities listed on any securities exchange. Therefore, there are no external analysts that provide coverage of EGD on a stand-alone basis.
- b) and c) See a) above.

Witness: B. Yuzwa

BOARD STAFF INTERROGATORY #91

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGDI's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

Enbridge has disclosed the long-term liability for SRC since 2009. Why are the analysts now concerned?

RESPONSE

See the response to Board Staff Interrogatory #90, at Exhibit I.E40.EGDI.STAFF.90

BOARD STAFF INTERROGATORY #92

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

Did Enbridge's plans to adopt USGAAP cause the change in accounting policy to reduce accumulated depreciation and to increase the long-term liability? Please explain.

RESPONSE

Please refer to Enbridge's response to Board Staff Interrogatory #79 at Exhibit I.E40.EGDI.STAFF.79.

Witnesses: C. Ho
B. Yuzwa

BOARD STAFF INTERROGATORY #93

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

Did the adoption of USGAAP result in increased scrutiny of the company's financial statements by buy-side and sell-side analysts? Please explain fully. Please file on the record the analysts' reports.

RESPONSE

Enbridge Gas Distribution Inc. ("EGDI") does not have equity securities listed on any securities exchange. Therefore, there are no external analysts that provide coverage of EGDI on a stand-alone basis

BOARD STAFF INTERROGATORY #94

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

If one divides the SRC liability of \$859.0 million by \$50 million (see revenue requirement impact identified by Gannett Fleming above), this implies 17 to 18 years remaining in the long-term liability related to SRC if collection from ratepayers was immediately paused or suspended. Why would Enbridge require 17 years of funding in advance under this scenario of suspending further collection from ratepayers?

RESPONSE

The eventual cost of removal and site restoration of the assets currently in service exceeds the amount of required SRC funding at this point in time. As indicated in Attachment 1 it is estimated that approximately \$3 billion of funds will be required for the eventual removal and retirement of the \$5.9 billion of assets in service as of December 31, 2010. As such, notwithstanding that the SRC fund is considered to be over-funded by an estimated amount of \$292 million as of December 31, 2010, the fund will require a significant level of funding over the remaining life of the assets currently in service.

The concept of generational equity provides that the level of the SRC fund at any time should reflect the consumption of the service value of assets in service at any given point in time. As such, when a test of adequacy of the SRC fund was made as of December 31, 2010 incorporating the use of the CDNS method, indications were that the fund was over-funded giving recognition to the estimated future use of the assets in service, and the availability of the assets in service to historic users of the system.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

Given the above, it is not correct to assume that the future removal of assets have been funded 17 years in advance. In fact, the past, current and future users are expected to appropriately fund the SRC over the entire remaining life of the assets currently in service.

It should also be noted, that EGDI is not proposing the suspension of any future funding of the SRC. Rather, at this time, a separate proposal related to the refund of the over-funded component as at December 31, 2010 is incorporated into this application.

Witnesses: B. Yuzwa
L. Kennedy – Gannett Fleming

ENBRIDGE GAS DISTRIBUTION, INC.
SUMMARY OF FUNDS REQUIRED AT RETIREMENT FOR SITE RESTORATION AND REMOVAL

Account	Description	Salvage %(*)	Original Cost	Required Funds at Retirement
453	WELLS	(5)	39,390,933	1,969,547
455	FIELD LINES	(5)	46,727,710	2,336,386
456	COMPRESSOR EQUIPMENT	(5)	91,781,488	4,589,074
457	MEASURING AND REGULATING EQUIPMENT	(5)	11,556,320	577,816
473	SERVICES	(45)	2,024,545,899	911,045,655
475.1	MAINS - CAST IRON	(125)	5,475,959	6,844,949
475.2	MAINS-BARE STEEL	(125)	9,114,623	11,393,279
475.21	MAINS - COATED STEEL	(90)	1,013,837,310	912,453,579
475.3	MAINS - PLASTIC	(85)	1,329,234,200	1,129,849,070
477	MEASURING AND REGULATING EQUIPMENT	(5)	314,899,807	15,744,990
			4,886,564,249	2,996,804,344

(*) The net salvage percentages reflect the results of the net salvage study completed in 2011, and do not incorporate the results of the 2012 negotiated settlement process.

BOARD STAFF INTERROGATORY #95

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

What prevents Enbridge from refunding \$859.0 million to ratepayers now, and then only collecting in future rates the amount actually needed for site restoration in each year? In this manner would the inflationary impacts of the new construction for PP&E additions match the inflationary pressures related to site restoration? Please explain.

RESPONSE

If EGD was to refund the entire SRC reserve of \$859 million, there would be no funded reserve related to the assets in service, notwithstanding that the current asset base has been in service for a number of years and has a depreciated service value. In this circumstance historic toll-payers would have funded within their historic tolls the current balance of \$859 million, current toll-payers over the next five-year period would be the beneficiaries of not only a free-ride (with regard to the funding of the future removal of assets that they are currently using) but would also receive a tolling reduction of the funds paid by users to the direct account of the future users of the system who will be responsible for 100% of the SRC costs of the assets for which they will only consume a fraction of the service value.

The approach as suggested in this information request has become known as a "pay as you go" approach. However, Gannett Fleming notes that allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts¹ and most Uniform Systems of Accounting including those

¹ Such as Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Published, Iowa State University Press, 1994; and Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute, 1997.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Fleming

published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage.

Additionally, the FERC Uniform System of Accounts requires that depreciation be recognized through accrual accounting. That is, the service value of an asset must be accrued during the life of the asset. Since net salvage is a part of the service value, it must be accrued during the life of the related asset in order to comply with the FERC Uniform System of Accounts. As such, regulatory decisions that require the expensing of costs of removal or that mandate the inclusion of costs of removal of retired plant as part of future capital costs of replacement plant need to understand that the decisions are in contrast to the FERC published and long-followed net salvage concepts from regulatory jurisdictions throughout North America.

The revenue requirements that result from any type of “expensing as incurred” or “pay as you go” options are greater than the revenue requirements that result from accruing for net salvage during the life of the related asset for a regulated utility that includes a rate of return in its revenue requirement. Although a comparison of the current revenue requirements related to a net salvage accrual and the current revenue requirements related to expensing of net salvage may indicate that the accrual is higher at a single point in time, over time the revenue requirements and the present value of those revenue requirements will be less if the net salvage cost is accrued over the life of the asset.

The reason for the lower revenue requirements with the accrual of net salvage is the impact of the accruals on rate base. That is, as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods.

The use of a pay as you go method has been debated in regulatory proceedings across Canada in recent years. Specifically, a pay as you go approach was over-turned in 2011 FortisBC Energy Proceeding before the British Columbia Utilities Commission. In the FortisBC Energy Decision the BCUC stated as follows:

The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a “pay as you go system” to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Fleming

While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC."²

It agreed that in a pay as you go method as suggested in the information request that the inflationary impacts of the new construction for PP&E additions match the inflationary pressures related to site restoration. However, it is also noted that the inflationary impacts associated with the net salvage calculations are normalized and dealt with in the CDNS method as proposed in this application. While it is agreed that PP&E additions for the replacement of retired assets will occur at generally the same time as removal and restoration of the retired assets, under a pay as you go approach it results in the future users of the system paying for both the removal of the assets for which there is no longer any benefit and additionally for the costs of the replacement assets. The long standing regulatory practice of including a net salvage provision in depreciation rates results in a far better match to the use of the assets. Furthermore, the use of the CDNS calculation method to determine the amounts to include in the depreciation rate calculation result in an improved matching of any inflationary impacts.

² BCUC Order G-44-12 resulting from an Application by The FortisBC Energy Utilities in respect of 2012/2013 Revenue Requirements and Rates, pages 83-84.

Witnesses: B. Yuzwa
L. Kennedy - Gannett Fleming

BOARD STAFF INTERROGATORY #96

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

What are the economic and financial benefits to Enbridge related to the return on a higher rate base from 2014 through 2018? Please provide a table that calculates all of the components of the benefits.

RESPONSE

The forecast impacts of the proposed site restoration cost changes on rate base and return are summarized in the table below.

Line No.	(\$ Millions)	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		2014	2015	2016	2017	2018
		EGD Total	EGD Total	EGD Total	EGD Total	EGD Total
1.	Rate base as filed	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1
2.	Rate base excluding the impact of SRC adj.	4,377.0	4,647.2	5,280.1	5,400.4	5,499.5
3.	Variance	54.6	150.4	244.3	336.2	406.6
4.	Equity component % of rate base	36.00%	36.00%	36.00%	36.00%	36.00%
5.	Equity component of rate base variance \$	19.7	54.1	87.9	121.0	146.4
6.	Equity return %	9.27%	9.72%	10.12%	10.17%	10.27%
7.	Incremental EGD return due to SRC adj. proposal	1.8	5.3	8.9	12.3	15.0

Witnesses: K. Culbert
B. Yuzwa

BOARD STAFF INTERROGATORY #97

INTERROGATORY

ISSUE E40: Are the proposed amounts to be returned to ratepayers over a 5 year period related to the estimated reduction to the amount of SRC/ARO previously collected, appropriate?

Evidence Ref:

- EGD's audited financial statements for 2009 through 2012
- Rate base fixed asset continuity schedules
- D1/T5/S1
- D2/T1/S1

How would the increased benefits to Enbridge calculated in the prior interrogatory through higher rate base compare to the benefits of refunding \$269 million to ratepayers over 5 years through to 2018 as proposed in this application?

RESPONSE

Assuming that what is being requested is a simple comparison of the increased EGD earnings calculated in the prior Board Staff interrogatory to the amount proposed to be credited to ratepayers, \$292.8¹ million over the 2014 to 2018 Customized IR term, then the comparison is shown in the table below.

	<u>Increased Earnings</u>	<u>Ratepayers' Credit</u>
	(\$Millions)	(\$Millions)
2014	1.8	74.7
2015	5.3	69.7
2016	8.9	64.7
2017	12.3	59.7
2018	15.0	24.0
Total	<u>43.3</u>	<u>292.8</u>

¹ As shown in evidence at Exhibit D2, Tab 1, Schedule 1, pages III-5 through III-8.

Witnesses: K. Culbert
B. Yuzwa

APPrO INTERROGATORY #15

INTERROGATORY

Reference: Exhibit H1 Schedule 2

Preamble: Enbridge is looking to make very significant changes to Rate 100. Enbridge states that customers are not using this service to date as those with higher load factors use either Rate 110 or 115, or generally take service under Rate 6. Enbridge further indicates that any new customer may have to pay a capital contribution. APPrO is interested in understanding the implications of this proposed change.

Issue: 42. Are the proposed changes to Rate 100 and Rate 110 appropriate?

Questions:

- a) Please provide the derivation of the individual components of the proposed rate.
- b) Please do an annual cost comparison (showing the costs for individual rate components) for 3 hypothetical customers having a load factor of 20% under Rate 6 (existing) , Rate 100 (existing) and Rate 100 (proposed) with a CD of:
 - i. 20,000 m³/d
 - ii. 80,000 m³/d
 - iii. 130,000 m³/dIgnore any potential capital contributions that may be required from a new customer. If other assumptions are required to complete the calculations, please make such reasonable assumptions and so indicate.
- c) Enbridge indicates that about 33 general service customers and 2 potential customers could use this option.
 - i. Please confirm that substantially more existing customers could use this service than new customers
 - ii. One of the stated reasons to make the proposed change is the level of capital contribution that may be required from a new customer. Please state Enbridge's policy with respect to the requirement for economic feasibility and potential capital contribution for an existing customer
- d) Please confirm that there may be customers with a low load factor that makes them ineligible for rate 110 or rate 115 and that Enbridge may also be unwilling for them to use rate 6 under certain circumstances, which may be forced to use rate 100, with its proposed high demand charges.

Witnesses: J. Collier
A. Kacicnik

RESPONSE

- a) To generate the proposed contract demand charge the level of costs was derived that would be allocated to migrated customers under the proposed Rate 100. The allocated fixed costs were then divided by the customers' contract demand and further divided by 12 (as contract demand charges are billed monthly). This yielded the proposed delivery charge per cubic metre of Contract Demand of 37.0 c/m³.

The proposed variable delivery charge of approximately 0.15 c/m³ recovers the cost of unaccounted for gas (note that the same unit rate is embedded in delivery rates for all bundled customer classes).

As outlined in the evidence at Exhibit H1, Tab 2, Schedule 2, pages 3 and 4, the Company proposes to tie load balancing, transportation, and gas supply charges to rates for these services under Rate 6. While there is no differentiation between transportation and gas supply charges amongst the various customer classes, using Rate 6 load balancing charge as a proxy is appropriate given that Rate 6 load balancing charges reflect low load factor customers. Once customers start taking service under the proposed rate, the load balancing charge will be designed to reflect their consumption characteristics.

- b) Table below shows annual bill comparison for the three hypothetical customers as referenced in the question above:

		<u>ANNUAL BILL COMPARISON</u>								
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		<u>CD=20,000 m³ per day, LF 20%</u>			<u>CD=80,000 m³ per day, LF 20%</u>			<u>CD=130,000 m³ per day, LF 20%</u>		
Item No.		Rate 6	Rate 100 Existing	Rate 100 proposed	Rate 6	Rate 100 Existing	Rate 100 proposed	Rate 6	Rate 100 Existing	Rate 100 proposed
1.1	VOLUME	m ³ 1,460,000	1,460,000	1,460,000	5,840,000	5,840,000	5,840,000	9,490,000	9,490,000	9,490,000
1.2	CUSTOMER CHG.	\$ 840	1,464	1,464	840	1,464	1,464	840	1,464	1,464
1.3	DELIVERY CHG.	\$ 47,436	70,879	90,951	184,648	268,216	363,802	298,991	432,664	591,179
1.4	LOAD BALANCING CHG.	\$ 8,008	5,300	8,008	32,033	21,200	32,033	52,054	34,451	52,054
1.5	TRANSPORTATION CHG	\$ 67,903	67,903	67,903	271,612	271,612	271,612	441,369	441,369	441,369
1.6	GAS SUPPLY CHG.	\$ 180,233	178,361	180,233	720,930	713,443	720,930	1,171,512	1,159,344	1,171,512
1.7	TOTAL BILL	\$ 304,419	323,907	348,558	1,210,063	1,275,935	1,389,842	1,964,766	2,069,292	2,257,578

Witnesses: J. Collier
A. Kacicnik

- c)
 - i. Not confirmed. The proposed changes to Rate 100 will provide an additional service option for large customers with low load factors. Having said that, it could be new customers (with low load factor operations) that will make use of this service option the most.
 - ii. Should an existing customer switch from one rate option (i.e., customer class) to another rate option, then the feasibility analysis for that customer is re-evaluated, which could result in an adjustment to the capital contribution paid by the customer.
- d) Not confirmed. Customers have a choice of different rate and service options (assuming that the customer's consumption characteristics qualify them for a number of rate options, or at least two options).

CME INTERROGATORY #17

INTERROGATORY

Issue: E42

Reference: Exhibit H1, Tab 2, Schedule 2

Please provide a schedule which will show the existing charges currently paid by small, typical and large Rate 100 customers and how those charges will change, if at all, under the auspices of the changes EGDI is proposing.

RESPONSE

Please see the table below showing a comparison between the existing and the proposed charges for sample customers:

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
			CD=10,000 m3 per day, LF 10%		CD=80,000 m3 per day, LF 10%		CD=150,000 m3 per day, LF 10%	
			Rate 100 Existing	Rate 100 proposed	Rate 100 Existing	Rate 100 proposed	Rate 100 Existing	Rate 100 proposed
1.1	VOLUME	m ³	365,000	365,000	2,920,000	2,920,000	5,475,000	5,475,000
1.2	CUSTOMER CHG.	\$	1,464	1,464	1,464	1,464	1,464	1,464
1.3	DELIVERY CHG.	\$	25,165	44,938	175,970	359,501	325,482	674,065
1.4	LOAD BALANCING CHG.	\$	1,325	2,002	10,600	16,017	19,875	30,031
1.5	TRANSPORTATION CHG.	\$	16,976	16,976	135,806	135,806	254,636	254,636
1.6	GAS SUPPLY CHG.	\$	44,590	45,058	356,721	360,465	668,852	675,872
1.7	TOTAL BILL	\$	89,520	110,438	680,562	873,253	1,270,309	1,636,068

Witnesses: J. Collier
A. Kacicnik

CME INTERROGATORY #18

INTERROGATORY

Issue: E42

Reference: Exhibit H1, Tab 2, Schedule 3

Please provide a schedule which will show the existing situation for customers served on Rate 110 and how the prices paid will change for those customers under the auspices of a rate with a 40% rather than a 50% Load Factor eligibility requirement.

RESPONSE

Please refer to the response to OAPPA IR #7 at Exhibit I.E42.EGDI.OAPPA.7, part (d).

Part (d) of this interrogatory question asks about the impact on the remaining Rate 6 customers if one-third of the approximately 300 eligible Rate 6 customers switch to Rate 110.

The response shows this if approximately one third of 336 customers chose to migrate from Rate 6 to Rate 110, the associated revenue deficiency would be approximately \$0.7 million. The revenue deficiency arises due to migrated customers paying less under Rate 110 service versus Rate 6 service.

Witnesses: J. Collier
A. Kacicnik

CME INTERROGATORY #19

INTERROGATORY

Issue: E42

Reference: Exhibit H1, Tab 2, Schedule 3

For the 80 General Service customers who have a Load Factor greater than 40% and an annual volume greater than 340,000 m³, please provide schedules which will show the likely impact on them of moving to proposed Rate 110 rather than continuing to take service under the auspices of EGDI's General Service rate. Please provide a similar schedule for the 300 General Service customers referenced in paragraph 9 of Exhibit H3, Tab 2, Schedule 3.

RESPONSE

For approximately 86 customers who have a Load Factor greater than 50% and an annual volume greater than 340,000 m³, the total combined impact is shown below:

Per Year	Rate 6	Rate 110	\$ Difference
Number of Customer	86	86	
Customer Charge	\$72,240	\$606,166	
Contract Demand Charge	\$0	\$1,001,157	
Delivery Charge	\$2,439,446	\$417,527	
Load Balancing Charge	\$401,951	\$60,582	
Transportation Charge	\$3,408,176	\$3,408,176	
System Gas Supply Charge	\$9,046,218	\$8,993,603	
Total Annual Bill	\$15,368,031	\$14,487,211	(\$880,820) -6%

For an average customer from above with a Load Factor greater than 50% and an annual volume greater than 340,000 m³, the likely impact is shown in the table below:

Witnesses: J. Collier
A. Kacicnik

Per Year	Rate 6	Rate 110	\$ Difference
Customer Charge per Customer	\$840	\$7,048	
Contract Demand Charge per Customer	\$0	\$11,641	
Delivery Charge per Customer	\$28,366	\$4,855	
Load Balancing Charge per Customer	\$4,674	\$704	
Transportation Charge per Customer	\$39,630	\$39,630	
System Gas Supply Charge per Customer	\$105,189	\$104,577	
Annual Bill per Customer	\$178,698	\$168,456	(\$10,242) -6%

For approximately 336 customers who have a Load Factor between 40% and less than 50% and an annual volume greater than 340,000 m³, the total combined impact is shown below:

Per Year	Rate 6	Rate 110	\$ Difference
Number of Customer	336	336	
Customer Charge	\$282,240	\$2,368,276	
Contract Demand Charge	\$0	\$4,755,525	
Delivery Charge	\$9,285,970	\$1,554,322	
Load Balancing Charge	\$1,528,697	\$230,405	
Transportation Charge	\$12,961,959	\$12,961,959	
System Gas Supply Charge	\$34,404,532	\$34,204,426	
Total Annual Bill	\$58,463,397	\$56,074,912	(\$2,388,485) -4%

For an average customer from above with a Load Factor between 40% and less than 50% and an annual volume greater than 340,000 m³, the likely impact is shown below:

Per Year	Rate 6	Rate 110	\$ Difference
Customer Charge per Customer	\$840	\$7,048	
Contract Demand Charge per Customer	\$0	\$14,153	
Delivery Charge per Customer	\$27,637	\$4,626	
Load Balancing Charge per Customer	\$4,550	\$686	
Transportation Charge per Customer	\$38,577	\$38,577	
System Gas Supply Charge per Customer	\$102,394	\$101,799	
Annual Bill per Customer	\$173,998	\$166,890	(\$7,109) -4%

Witnesses: J. Collier
A. Kacicnik

OAPPA INTERROGATORY #6

INTERROGATORY

Issue 42 - Are the proposed changes to Rate 100 and Rate 110 appropriate?

(Reference: Exhibit H1, Tab 2, Schedule 2)

- (a) Please provide a Rate 6 versus Rate 100 annual bill comparison, on a T-service basis, for a customer that is currently on Rate 6 and could choose service under the new Rate 100 with the proposed applicability provision and rate design in place. Please show the comparison for a customer at the low end of the maximum daily volume range and also at the high end.
- (b) Enbridge indicates that if the proposal for Rate 100 is approved, then it will contact the general service customers that could switch to the new Rate 100 to discuss the new option. Should a customer opt to switch, what would be the timing for making the change?
- (c) If all 33 of the current general service customers who could choose the new Rate 100 option were to do so, what would be the estimated annual bill impact, on a T-service basis, for the average customer remaining in Rate 6?

RESPONSE

- a) Please refer to the response to APPrO Interrogatory #15 at Exhibit I.E42.EGDI.APPrO.15, Part b, i, ii and iii.
- b) As stated in the evidence at Exhibit H1, Tab 2, Schedule 2, page 4, following the approval of the proposed change to the Rate 100 service, the Company will contact eligible general service customers to inform them of the change and to discuss/evaluate this rate option with them based on their specific needs and consumption characteristics. The Company expects customers to evaluate this rate option thoroughly. The customer could switch to Rate 100 once they completed the evaluation and made the choice to take service under Rate 100.
- c) Should these general service customers chose to migrate from Rate 6 to Rate 100, the outcome would be a minor bill decrease for the average customer remaining in Rate 6. This is due to migrated customers paying more under Rate 100 versus Rate 6.

Witnesses: J. Collier
A. Kacicnik

OAPPA INTERROGATORY #7

INTERROGATORY

Issue 42 - Are the proposed changes to Rate 100 and Rate 110 appropriate?

(Reference: Exhibit H1, Tab 2, Schedule 3)

- (a) How does lowering the minimum load factor requirement for Rate 110 from 50% to 40% address the feedback that Enbridge received that for some Rate 6 customers, the bill savings resulting from a switch to a contract class are not large enough to warrant the additional obligations and responsibilities of a contract rate?
- (b) Please provide a Rate 6 versus Rate 110 annual bill comparison, on a T-service basis, for a typical customer that is currently on Rate 6 and could choose service under Rate 110 with the proposed applicability provision in place.
- (c) Enbridge indicates that if the proposal for Rate 110 is approved, then it will contact the general service customers that could switch to Rate 110 to discuss the new option. Should a customer opt to switch, what would be the timing for making the change?
- (d) What would be the estimated annual bill impact, on a T-service basis, for the average customer remaining in Rate 6 if say one-third of the approximately 300 current general service customers who could switch to Rate 110 with the proposed applicability provision in place were to do so?

RESPONSE

- (a) As stated in the evidence at Exhibit H1, Tab 2, Schedule 3, pages 2 to 4, the purpose of the proposal to lower the load factor requirement for Rate 110 is two-fold:

First, customers who implement energy efficiency/conservation measures typically see their load factor decline (i.e., their annual consumption declines proportionally more than their peak consumption, thereby, resulting in a decline in load factor). The lower load factor requirement would facilitate continuity of service under Rate 110 for customers who undertake energy conservation and energy efficiency initiatives.

Witnesses: J. Collier
A. Kacicnik

Second, it would provide an option, a choice for general service customers with load factors greater than 40% (and annual consumption greater than 272,290 m³ and a minimum peak daily demand of 1,865 m³) to take service under Rate 110.

The feedback from customers who have a load factor greater than 50% and annual volume greater than 340,000 m³ and who are presently eligible to take service under Rate 110 (with the current load factor requirement of at least 50%) indicated that:

- most of these customers have a large heat sensitive component to their load, therefore, their annual consumption and their load factor would fluctuate considerably year-to-year as a function of weather. Further, some of the customers face uncertainty regarding the level of their annual consumption volumes due to changes in demand for their product (i.e., they may reduce the number of shifts, eliminate weekend work). This could result in customers not being able to maintain the minimum eligibility requirements under Rate 110 and would need to switch back to the general service rate;
- some customers are not interested in a contract rate due to additional responsibilities and obligations that come with service under a contract rate; and
- some customers felt that bill savings versus Rate 6 service are not large enough to warrant taking on obligations and responsibilities of a contract rate.

The customer feedback from above shows that customers, when choosing rate and service options, take into account a number of considerations, one of them being bill savings.

This proposal provides an option for general service customers on Rate 6 with load factors greater than 40% (and annual consumption greater than 272,290 m³ and a minimum peak daily demand of 1,865 m³) to take service under Rate 110. The Company expects customers to evaluate this rate option thoroughly and make decisions based on their specific needs and consumption characteristics.

- (b) For an average customer with a load factor between 40% and less than 50%, a T-service bill comparison between Rate 6 charges and Rate 110 charges is presented in the table below:

Witnesses: J. Collier
A. Kacicnik

Per Year	Rate 6	Rate 110	\$ Difference
Number of Customer	336	336	
Customer Charge per Customer	\$840.00	\$7,048	
Contract Demand Charge per Customer	\$0.00	\$14,153	
Delivery Charge per Customer	\$27,637	\$4,626	
Load Balancing Charge per Customer	\$4,550	\$686	
Transportation Charge per Customer	\$38,577	\$38,577	
Total T-Service Annual Bill per Customer	\$71,604	\$65,091	(\$6,513) -9%

- (c) As stated in the evidence at Exhibit H1, Tab 2, Schedule 3, page 4, following the approval of the proposed change to the Rate 110 load factor requirement, the Company will contact eligible Rate 6 customers to inform them of the change in Rate 110 applicability and to discuss/evaluate this rate option with them based on their specific needs and consumption characteristics. The Company expects customers to evaluate this rate option thoroughly. The customer could switch to Rate 110 once they completed the evaluation and made the choice to take service under Rate 110. The switch would likely take place at the time of contract renewals.
- (d) Should approximately one third of 336 customers choose to migrate from Rate 6 to Rate 110, the associated revenue deficiency would be approximately \$729,460 (i.e., $[\$6,513 \times 336] / 3 = \$729,460$). The revenue deficiency arises due to migrated customers paying less under Rate 110 versus Rate 6. This deficiency amount would result in approximately 0.04% impact on the T-service annual bill for the average customer remaining in Rate 6.

Witnesses: J. Collier
A. Kacicnik

APPrO INTERROGATORY #16

INTERROGATORY

Reference: Exhibit H1 Tab 2 Schedule 1 plus Attachment Section P

Preamble: Enbridge is proposing to make it mandatory to require customers using more than 1,000,000 m³ annually to provide to the Company their expected annual consumption, peak demand and emergency contact information

Issue: 43. Are the proposed changes to the Rate Handbook appropriate?

Questions:

- a) Enbridge states that change will not have undue impact on the 275 customers that receive service under a contract, and further that this information is updated and refreshed annually through the contract renewal process. Please confirm that some contracts are long term in nature and do not require annual renewal.
- b) For those contract customers not subject to annual renewal where this information is embedded in the contract, are all provisions of Section P intended to apply. Explain.
- c) Enbridge states that this information is required to have the best information available for gas distribution planning and day-to-day safe and reliable operation of the system.
 - a. Please state which departments within the Company will have access to this information, and specifically how and under what circumstances it will be used.
 - b. Please state how having the projected annual consumption and peak demand information for unbundled and other long term, large volume contract customers that supply their own gas contributes to gas distribution planning and safe and reliable operation of the system.
 - c. Please confirm that if any of this information is provided by a customer to the Company that it will not in any way reduce a customer's rights under its contract.
 - d. Volume information may be considered privileged and commercially sensitive by some customers. Please state what safeguards are currently in place to protect this information.

Witnesses: J. Collier
A. Kacicnik

RESPONSE

(a) Confirmed.

(b) As confirmed in part (a) of the response, longer term contracts do not require annual renewal. Having said that, longer term contract customers fulfill the intent of the proposed Section P through the "Annual Consumption Forecast" provision/clause within the longer term contracts. This provision stipulates that:

The customer shall provide to the Company, for each Terminal Location, not less than sixty (60) days prior to the commencement of each Contract Year for such Terminal Location, an annual forecast of daily gas consumption expressed in cubic metres identifying expected daily flows, expected down times and anticipated peak consumption periods.

While the above provision does not require the customer to review and update the emergency contact information annually, the Company expects the longer term contract customers to do so given that the customer is required to monitor the emergency contact twenty-four (24) hours per day, seven (7) days a week during the contract term.

(c)

a and b.

Strategic & Key Accounts and System Analysis & Design departments will have access to the information collected in meetings with customers as per the proposed Section P.

As outlined in the evidence at Exhibit H1, Tab 2, Schedule 1, pages 1 and 2, the proposed provision formalizes the Company's need to have the most current emergency contact information and consumption information for its largest customers and formalizes the obligation for customers to provide such information. The proposed provision aligns well with the Company's continued efforts to increase safety and reliability of its gas distribution system. It means that the Company would have the most current and the best possible information available for gas distribution system planning and day-to-day safe and reliable operation of the system, as well as, to have the most up-to-date customer emergency contact information on file in case of emergencies.

c. Confirmed.

- d. The staff from Strategic & Key Accounts and System Analysis & Design departments who will have access to the information collected in meetings with customers undergo privacy awareness training. Further, the customer information is password protected and accessible to authorized staff only. The confidentiality provisions and requirements of the contracts will be respected.

CCC INTERROGATORY #31

INTERROGATORY

Issue E43 – Are the proposed changes to the rate handbook appropriate?

(Ex. A1/T5/S1) The evidence state that in an effort to improve customer satisfaction and enhance customers experience with EGD that it is currently undertaking a Bill Presentment project to enhance the way information is provided on the bill. Please describe the full scope of this project. What is the cost of the project and how are those costs going to be recovered? Will this involve changes to the billing system with associated costs? If so, what is the current estimate of those costs? What is the expected timing of any changes?

RESPONSE

This interrogatory poses five questions concerning the Company's Bill Presentment Project.

- 1) Please describe the full scope of this project.
- 2) What is the cost of the project and how are those costs going to be recovered?
- 3) Will this involve changes to the billing system with associated costs?
- 4) If so, what is the current estimate of those costs?
- 5) What is the expected timing of any changes?

Answers:

1. Please describe the full scope of this project.
The purpose of the Bill Presentment Project is to improve customer satisfaction by improving the clarity of the bill. Specifically, this means presenting Enbridge's customers with information about their bill in a more meaningful way, with easy to understand terms. To support this initiative Enbridge has engaged the services of a graphic design firm to advise on and develop the bill designs that will result in a completely new Enbridge invoice format. For the most part the current Enbridge invoice is created from an inside-out perspective focusing the Company's requirements with respect to conveying billing information and the collection process. This has resulted in a detailed bill that does not communicate billing information to customers in an effective, easily understood format.

The Company conducted customer focus groups and worked with customer care support personnel from Enbridge and its service provider in 2013 to learn how

Witnesses: K. Lakatos-Hayward
S. McGill

customers perceive the Enbridge invoice and to learn how the invoice could be modified to make the information presented on it more easily understood and useful for customers. The results of this feedback have served as input to this project. The new Enbridge invoice format will cover all customer segments (Residential, Commercial, and Large Volume/Industrial) and also take into account specific business needs that pertain to Open Bill Access, the Budget Billing Plan, and Gas Marketers. The project will evaluate and determine changes that will be required to billing stationery and associated printing requirements.

2. What is the cost of the project and how are those costs going to be recovered?
The total capital cost of this project is \$2.7 million. This expense pertains largely to changes to the Company's CIS and the Company's bill print vendor's systems which are necessary to compose and print the Enbridge bill in the new format. Other service providers have been engaged and will be required to conduct customer research, provide graphic design services, provide braille translation compliant with the new invoice design, and test the new bill layout for payment processing purposes. The Company estimates that it will incur approximately \$950,000 of this cost in 2013, with the balance of the total capital cost of the project to be incurred in 2014. These capital costs have been included in the Company's 2013 and 2014 capital budgets. With respect to Operating and Maintenance Costs ("O&M") the Company anticipates that the new Enbridge invoice will result in an increase in Customer Care O&M of \$115,000 in 2014 and approximately \$425,000 per year thereafter. These amounts will be accommodated within the Customer Care O&M budget established in the CIS/Customer Care Settlement Agreement.
3. Will this involve changes to the billing system with associated costs?
Changes to the Company's CIS will be required as part of this project. The costs related to these changes are noted in part 2 of this response.
4. If so, what is the current estimate of those costs?
The costs related to these changes are noted in part 2 of this response.
5. What is the expected timing of any changes?
The re-designed invoices are expected to be implemented and placed into production in October 2014.

OAPPA INTERROGATORY #8

INTERROGATORY

Issue 43 – Are the proposed changes to the Rate Handbook appropriate?

(Reference: Exhibit H1, Tab 2, Schedule 1) - For the Rate 6 customers who will be obligated to provide information under the proposed Section P, what will Enbridge use as the source for determining the customer's peak demand?

RESPONSE

As noted in the evidence at Exhibit H1, Tab 2, Schedule 1, page 2, the Company plans to assist general service customers to prepare for the meetings by providing them with their historical consumption information and emergency contact information that the Company has on file in advance of the meetings. Consequently, the focus of the meetings will be to establish any expected deviations/variances from the past consumption pattern (i.e., anticipated addition or loss of load) and to verify that the emergency information on file is indeed current.

With respect to the customer's peak demand, for customers who have automated daily meter reading the customer's maximum daily consumption as recorded by daily meter readings will be used as the peak demand. The majority of customers subject to the proposed Section P have automated daily meter reading. For the few customers who do not have automated daily meter reading, the customer's maximum monthly consumption divided by the number of days in the month will be used to derive an estimated peak daily demand.

Please note that the goal of the proposed provision is for the Company to have the most current and the best possible information available from its largest customers for gas distribution system planning and day-to-day safe and reliable operation of the system, as well as the most up-to-date customer emergency contact information.

Witnesses: J. Collier
A. Kacicnik

OAPPA INTERROGATORY #9

INTERROGATORY

Issue 43 – Are the proposed changes to the Rate Handbook appropriate?

(Reference: Exhibit H2, Tab 6, Schedule 1)

- (a) Rider H (Balancing Service Rider) sets out a Bundled Service Charge for Enhanced Title Transfer Service that is defined in terms of the difference between TransCanada PipeLines Firm Transportation tolls for the Eastern Zone and the Southwest Zone. Given that TransCanada's toll zones have been eliminated as of July 1, 2013, how is this charge now defined?
- (b) Are there any other sections of the Rate Handbook requiring revision as a result of the implementation of TransCanada's new tolls?

RESPONSE

- (a) Given the elimination of TransCanada's toll zones, the Company proposes that the Enhanced Title Service ("ETT") Bundled Service Charge be determined as follows:
- Charge for pools with all CDA accounts = difference between TCPL's Enbridge CDA toll and TCPL's Enbridge SWDA toll;
 - Charge for pools with all EDA accounts = difference between TCPL's Enbridge EDA toll and TCPL's Enbridge SWDA toll;
 - Charge for pools with both CDA & EDA accounts = a weighted average of the above 2 tolls prorated based on the CDA account MDV volume versus the EDA account MDV volume.

Further, the wording for the ETT Bundled Service Charge within Rider H in the Rate Handbook needs to be amended to reflect the above. The Company will make a proposal to update the wording for the ETT Bundled Service Charge as outlined above when the EB-2012-0459 (2014 to 2018 Customized IR Plan) evidence is updated to reflect the decision in the GTA leave to construct proceeding.

- (b) No.

Witness: J. Collier

APPrO INTERROGATORY #17

INTERROGATORY

Reference: Exhibit C1 Tab 5 Schedule 1, and EB-2012-0451 Exhibit A Tab 3 Schedule 9 paragraph 30. And EB-2012-0451 Exhibit C Tab 2 Schedule 1 (2013-07-22)

Preamble: The evidence may be out of date. It is understood from the second reference, that 1,200 TJ (60%) of the total capacity of 2,000 TJ of Segment A will be used to accommodate transmission services under Rate 332.

Issue: 44. Is Enbridge's rate design for the proposed Rate 332 appropriate?

Questions:

- a) Please confirm that it is the Company's intention to allocate 60% of the cost of Segment A to Rate 332 rather than the 50% referenced in paragraph 4 of the first reference.
- b) Please explain how costs that are common to both Segment A and Segment B such as project management, regulatory, administration, etc., are allocated to each segment.
- c) Please confirm that 60% of the line pack gas required to pressurize and operate Segment A will also be allocated to Rate 332.
- d) In light of the Settlement Agreement between TransCanada, Enbridge, Union and GMi dated October 31, 2013 does any of the evidence regarding Rate 332 require updating? If so please revise accordingly.
- e) The third reference shows a total estimated capital cost of the GTA project as \$686.5 million. The first reference (which is less recent than the third reference) shows that the combined rate base for 2015 and 2016 as \$692.3 million. Is Enbridge intending to update this section based on the more recent capital cost estimate? Explain.

Witnesses: K. Culbert
C. Fernandes
A. Kacicnik

RESPONSE

- a) Confirmed. This is based on the latest LTC application information with Segment A size at NPS 42, which is pending a decision from the Board; Reply Argument was filed on November 25th, 2013.
- b) Forecast common project costs are allocated based on forecast direct base costs for each element of the project.
- c) Confirmed.
- d) As per the response to Board Staff Interrogatory #43 at Exhibit I.A12.EGDI.STAFF.43, the Company proposes to update its evidence concerning the GTA project once the Board has issued a Decision within the EB-2012-0451 Leave-to-Construct proceeding.
- e) See d)

Witnesses: K. Culbert
C. Fernandes
A. Kacicnik

CCC INTERROGATORY #32

INTERROGATORY

Issue E45 – Is the rate of return on the NGV program appropriate?

(Ex. A2/T1/S1/p. 18) Capital expenditures for NGV rental equipment is increasing in 2014 and beyond by about \$3 million per year relative to 2013 levels. Please explain why there is increased spending.

RESPONSE

Capital expenditures in 2014 to 2016 are forecast to increase as a result of an anticipated increase in customer interest in the CNG refueling station and VRA rental programs. These programs are described in paragraphs 19 and 20 of Exhibit B2, Tab 7, Schedule 1, page 6.

An explanation of the CNG refueling station program capital forecast can be found in the same exhibit on page 9, paragraphs 30 to 33; an explanation of the VRA rental program capital forecast can be found on page 10, paragraph 34 (with reference to Table 3).

CCC INTERROGATORY #33

INTERROGATORY

Issue E45 – Is the rate of return on the NGV program appropriate?

(Ex. B2/T7/S1/p. 3) Please provide detailed evidence to support the claim that the Natural Gas for Transportation market is on the verge of a renaissance.

RESPONSE

As outlined in the referenced exhibit, the natural gas for transportation market has become the focus of much interest in recent years. Assessments of the NGV market suggest that the most immediate opportunities for NGV are in medium and heavy duty applications, but that light duty could follow in the future. The key drivers from a consumer perspective are low cost, stably priced natural gas, and an ever increasing focus on reducing Greenhouse Gas (“GHG”) and other emissions. As a result of renewed consumer interest in NGV as a means to reduce operating costs and emissions, equipment and service providers have begun responding with an increased supply of products and services. This response of consumers and providers has been particularly strong in jurisdictions where government incentives exist.

Market Research

An example of a recent, publically available NGV market assessment is the 2010 report titled *Study of Opportunities for Natural Gas in the Transportation Sector* which was prepared by consulting firm Marbek for Natural Resources Canada (“NRCan”; Attachment 1). The report was used by NRCan and the Canadian Natural Gas Vehicle Alliance (“CNGVA”) as the basis for the creation of the *Natural Gas Use in the Canadian Transportation Sector - Deployment Roadmap*. The report suggests that the most immediate opportunities for NGV are in medium and heavy duty applications.

Natural Gas Pricing and Stability

An explanation of current trends in the North American natural gas supply and corresponding impacts on natural gas pricing and price stability may be found in the Canadian Gas Association’s (“CGAs”) *Natural Gas Supply Update, November 2011* (Attachment 2). One of the document’s key messages is that natural gas prices are expected to remain low and stable for many years.

Witness: R. Murray

An explanation of past trends and the likely future of natural gas pricing relative to crude oil (from which gasoline and diesel are produced, and therefore a proxy for those fuels) may be found in the Natural Resources Canada report, *Canadian Crude Oil, Natural Gas and Petroleum Products: Review of 2009 & Outlook to 2030* (May 2011; Attachment 3). Of particular interest are the plots on pages 20 and 30. The former is a plot illustrating historical natural gas prices relative to petroleum product prices. It illustrates the historic price relationship between oil and natural gas prices that occurred up until about 2008/2009 at which time natural gas prices began trending much lower than crude oil. The latter illustrates that, although natural gas prices are expected to increase in the future, crude oil prices are also expected to increase; natural gas is expected to experience a favourable price advantage over crude oil (and therefore gasoline and diesel) well into the future.

Focus on Greenhouse Gas (GHG) and other Emissions

Environment Canada's document titled *Canada's Emissions Trends 2012* (August 2012; Attachment 4) reiterates the federal government's intent to address the reduction of GHG in Canada, and that federal efforts are supported by the actions of several provinces and territories. Given that the transportation sector in North America is a significant emitter of GHGs and other emissions, some provincial governments have begun offering NGV related incentives to help with reductions.

In Canada, incentives are available in British Columbia and Quebec.

- *British Columbia* – flowing from the Government of BC's Greenhouse Gas Reduction regulation, in May 2012 FortisBC began providing incentive funding of up to 80% of the difference in cost for eligible medium and heavy natural gas vehicles.¹
- *Quebec* – in November 2013, the provincial government announcement that it will subsidize 30% of the additional cost, up to a maximum of \$75,000, for the purchase of vehicles running on natural gas as a source of fuel--in compressed or liquefied form.²

In the United States, incentives are widely available at the Federal^{3,4} and State⁵ levels, as reported by NGV America.

Evidence that private industry is also focused on GHG reductions can be found in the press releases and corporate social responsibility documents issued by such well-

¹ <http://www.fortisbc.com/NaturalGas/Business/NaturalGasVehicles/Incentives/Pages/default.aspx>

² <http://www.newswire.ca/en/story/1254139/natural-gas-for-transportation-gaz-metro-welcomes-the-measures-announced-today-by-the-government-of-quebec>

³ <http://www.ngvc.org/incentives/federalTax>

⁴ <http://www.ngvc.org/incentives/federalNGVGrantPrgs.html>

⁵ <http://www.ngvc.org/incentives/stateNGV.html>

known companies as: Canadian National Railway⁶, Canadian Tire⁷, Home Depot⁸, Ryder⁹ and WalMart¹⁰. (The foregoing list is not intended to be complete or all-inclusive).

Equipment Manufacturer and Service Provider Activity

Evidence that light and medium duty equipment manufacturers have begun responding with an increased supply of products may be found in an NGV America document titled, *Available NGV Aftermarket Conversion Systems* (Attachment 5). This document reports on,

... aftermarket conversion systems that consumers and businesses may purchase in order to modify new or used vehicles so that they can operate on natural gas. Some of these systems may be ordered directly through automotive dealerships when placing an order for a new vehicle.

The message this document sends is that there are many more light and medium duty NGV conversion and factory built options for North American consumers than there were a few years ago.

Evidence that heavy duty Original Equipment Manufacturers ("OEMs") have begun responding with an increased supply of products may be found in the observation that many major truck and bus manufacturers have begun offering factory-built NGVs. The list includes such well recognized names as Kenworth¹¹, International¹², Peterbilt¹³, Mack¹⁴, Thomas Built Bus¹⁵, Blue Bird Bus¹⁶, New Flyer¹⁷, Daimler¹⁸, Freightliner¹⁹ and

⁶ <https://www.cn.ca/en/delivering-responsibly/environment/emissions>

⁷ <http://www.canadianmanufacturing.com/general/canadian-tire-reduces-energy-consumption-ghg-emissions-58116>

⁸ <http://2sustain.com/2010/03/the-home-depot-sets-new-energy-use-and-ghg-emissions-targets.html>

⁹ <http://www.ryder.com/solutions/alternative-fuels-solutions/initiatives.aspx>

¹⁰ <http://corporate.walmart.com/global-responsibility/environment-sustainability/greenhouse-gas-emissions>

¹¹ <http://www.kenworth.com/news/news-releases/2011/december/kenworth-truck-company-offers-advice-on-specing-for-natural-gas-power.aspx>

¹² <http://www.internationaltrucks.com/trucks/naturalgas/>

¹³ <http://www.peterbilt.com/about/media/2012/346/>

¹⁴ <http://www.macktrucks.com/default.aspx?pageid=4338>

¹⁵ <http://www.thomasbus.com/earth-friendly/cng/>

¹⁶ <http://www.blue-bird.com/alternative-fuel-buses.aspx#.UpOY59JJP7A>

¹⁷ <http://www.newflyer.com/index/cng>

¹⁸ <http://www.daimler.com/dccom/0-5-1200798-1-1400953-1-0-0-1200840-0-0-135-0-0-0-0-0-0-0.html>

¹⁹ <http://www.freightlinertrucks.com/Trucks/Alternative-Power-Trucks/Natural-Gas/>

Westport Innovations²⁰. (The foregoing list is not intended to be complete or all-inclusive).

Evidence that large and small North American companies have begun responding to provide vehicle refueling solutions can be found in the number of companies that have recently created, expanded and/or revitalized their NGV related offerings in the United States, Alberta, British Columbia, Quebec, and to some extent Ontario. Table One provides a sampling of hyperlinks to websites and press releases with more information. This table is not intended to be complete or all-inclusive.

Table One – Links to North American Service Provider Websites and Press Releases

Company	Activity	Website
Clean Energy	Plans to complete 150 liquefied natural gas ("LNG") refueling stations across the USA by 2013/2014.	http://www.cleanenergyfuels.com/buildinamerica.html
Compression Technology Corp.	In 2009, becomes the Canadian distributor for BRC FuelMaker vehicle refueling appliances.	http://www.compression-technology.ca/index.php/about-ctc
ENN Canada and Ferus Natural Gas Fuels	Joint development of three LNG production facilities in Canada (none in EGD franchise).	http://www.calgaryherald.com/business/Chinese+company+retail+fuel+Canada/9185129/story.html
Faromor	Construction of CNG refueling stations in Ontario.	http://www.faromor.com/news-events/news/20130702
FortisBC	Regulated utility offering NGV and NGV refueling station incentives in British Columbia.	http://www.fortisbc.com/MediaCentre/NewsReleases/2012/Pages/FortisBC-launches-incentive-program-for-heavy-duty-natural-gas-vehicles.aspx
Gas Metro Transportation Solutions	Construction of LNG refueling stations in Quebec and Ontario.	http://www.corporatif.gazmetro.com/corporatif/communiquer/en/HTML/2754184_en.aspx?culture=en-ca
Landi Renzo	Product distribution partnership with National Energy Equipment, Canada's largest energy equipment distributor, for the complete line of Landi Renzo USA CARB and EPA certified alternative fuel Compressed Natural Gas (CNG) systems on various vehicle platforms.	http://www.landiusa.com/tag/ngv-canada

²⁰ <http://www.westport.com/products/fuel-storage-and-delivery/ice-pack-lng-tank-system>

Company	Activity	Website
Shell Canada	Currently constructing an LNG production facility and operating three natural gas refueling stations in Alberta.	http://business.financialpost.com/2011/09/07/shell-plans-alberta-lng-plant-to-supply-truck-fuel/?_lsa=d77b-05f6
Shell Canada	Plans to construct LNG production facility in Sarnia, ON, to serve the marine transportation market.	http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/shell-aims-to-fuel-great-lakes-freighters-with-liquefied-natural-gas/article9282660/

Renewed Consumer Interest

Evidence of renewed consumer interest in NGV is evident in recent sales figures and related statistics. For example,

- The Associated Press (via CTV) reports that Ford Motor Co. sold a record 11,600 natural gas vehicles in its 2012 model year, more than triple the number it sold in 2010²¹;
- In its testimony before the US Senate, the American Natural Gas Vehicle Coalition (“NGVC”) in July 2012 reported that NGV made up 40 percent of all refuse trucks ordered and 30 percent of transit bus orders in 2011²²; and
- A growing list of transit bus orders may be found at the Canadian Public Transit Discussion Board²³.

²¹ <http://www.ctvnews.ca/business/natural-gas-vehicle-sales-rising-1.1183384#ixzz2IIIItAJxm>

²² <http://www.gpo.gov/fdsys/pkg/CHRG-112shrg76518/html/CHRG-112shrg76518.htm>

²³ http://cptdb.ca/wiki/index.php?title=Current_Transit_Bus_Orders



Study of Opportunities for Natural Gas in the Transportation Sector

Submitted to
Natural Resources Canada

Submitted by
Marbek

March 2010

This study provides the perspective of numerous stakeholders. The contents, conclusions and recommendations are not necessarily endorsed by participating organizations and their employees or by the Government of Canada.

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Executive Summary

Background and Objectives

This report provides an assessment of the potential use of natural gas as an alternative fuel across the transportation sector. This includes the on-road and off road, marine, rail, and indoor equipment sectors. The report has been prepared for the Fuels Policy and Programs (FPP) division of Natural Resources Canada (NRCan).

The objectives of this study were:

- To explore and analyze the potential for the use of natural gas in support of the Government of Canada's policy objectives for the transportation sector.
- To conduct a study that includes research and information gathering to inform the development of a Canadian strategy for the use of natural gas in the transportation sector.
- To identify and explore other potential future applications for natural gas in the Canadian context within the transportation sector.

A preliminary assessment of previous, existing and future market and technology trends in North America and more specifically in Canada and consultation with Natural Gas Vehicle (NGV) industry stakeholders showed that the more promising NGV market segments are likely to consist of the following:

- Heavy duty and medium duty, including line haul trucking (fleets), return-to-base trucks, transit buses, refuse trucks
- Light duty fleets. Examples are taxis and courier services
- Marine vessels
- Rail (locomotive)
- Indoor industrial vehicles, including forklifts and ice re-surfacers.

These segments were selected to be included in the study of financial, environmental and achievable potentials.

Current Market

The Canadian market for NGVs has stagnated and is lagging far behind other countries. This is due to a variety of factors, including past price volatility and problems with NGV technologies in some sectors. The concurrent lack of availability of vehicles and of fuel continues to act as a "chicken and egg" barrier to further development.

Lessons Learned from Previous Programs

A variety of programs and policies to encourage the development of NGVs have been implemented in Canada and around the world, with varying levels of success. Key lessons include:

- Need for a stable and predictable price advantage for natural gas – mechanisms to manage risk are needed
- Technologies need to be commercially and financially viable on their own – government support should help overcome barriers but should be temporary

- Programs are more likely to be successful if federal, provincial and municipal governments cooperate
- Support is needed both for vehicles and for fuelling infrastructure.

Fuel Supply

The increased access to unconventional gas (in particular to shale gas) appears likely to lead to a surplus in North America by 2020. This surplus is not yet reflected in official forecasts and is subject to some uncertainty, including potential environmental concerns that could constrain the potential.

Current retail fuel supply is characterized by a lack of availability and a lack of competition. As a result, prices are higher than they need to be.

The analysis indicates that investments in fuelling infrastructure could be financially attractive even with somewhat lower prices. However, the business case depends on access to a sufficient market. Thus, potential investors may require assistance to deal with risk and to overcome the initial period of market development.

Technology Trends

The study indicates that NGV technologies are proven and commercially available for all market segments, except rail. In all cases, there remain incremental costs, but opportunities to reduce these costs are being pursued.

Emerging technologies, particularly in the HDV/MDV sector are particularly promising, with new developments signaling that tailpipe emissions are being reduced to a level that could eliminate the need for some of the costly exhaust after treatment components used by conventional fuel vehicles.

Environmental Analysis

The environmental analysis showed that GHG emissions can be reduced by 15-25% depending of the vehicle segment (greater reductions of up to 88% are possible by using biogas). The greatest reductions occur in medium and heavy duty, light duty and refuse truck segments.

It was also noted that NGVs offer other environmental advantages in several segments. In particular the reduction of CACs is important for indoor equipment.

The use of biogas is attractive for municipal fleets that are seeking to drastically reduce GHG emissions while using a locally available fuel source.

Financial Analysis

The financial analysis showed that all NGV segments could potentially be viable without incentives, except the refuse truck segment.

- The forklift segment offers the best return, almost 45%.
- Line haul, transit bus, LDV and marine segments offer attractive returns, in the range of 20%. Because of the large sums involved, the marine scenario is particularly attractive in terms of the absolute dollars.

- The Return-to-Base HDV scenario and the ice resurfacer scenario are only marginally viable, in the range of 10-15% return.
- The refuse truck segment could be financially viable if capital cost increment could be reduced, say by \$15,000.

Several of the segments/scenarios (e.g. refuse, ice resurfacer) have important non-financial advantages that could improve their prospects.

Barriers and Solutions

Despite their technical, financial and environmental benefits, NGVs still face formidable market and non-market barriers. Each of these barriers can be overcome but this will require concerted action by all stakeholders, including governments and industry. In particular a comprehensive communications strategy will be needed to overcome a lack of awareness, understanding and confidence on the part of stakeholders.

Achievable Potential

A number of segments of the market have the potential to see modest NGV penetration, notably the HDV segment.

Achieving this potential will require governments to play an active role, taking the lead in coordinating the actions of other players and providing targeted incentives for both vehicles and fuelling infrastructure.

If realized, this potential increase in NGV penetration would displace up to 850 million litres of conventional fuels per year and reduce GHG emissions by more than 2 megatonnes per year, by 2020.

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Glossary of Technical Abbreviations

AFV	Alternative fuel vehicle
CAC	Criteria air contaminants
CNG	Compressed natural gas
DPF	Diesel particulate filter
GGE	Gallons gasoline equivalent
GHG	Greenhouse gases
GVW	Gross vehicle weight
GVWR	Gross vehicle weight rating
HDV	Heavy duty vehicle
HP	Horsepower
HPDI	High pressure direct injection
LCD	Local (natural gas) distribution company
LDE	Litres Diesel equivalent
LDV	Light duty vehicle
LGE	Litres Gasoline equivalent
LNG	Liquefied natural gas
MDV	Medium duty vehicle
NG	Natural gas
NGV	Natural gas vehicle
OEM	Original equipment manufacturer
QVM	Qualified vehicle modifiers
SCR	Selective catalytic reduction
SI	Spark ignited
VRA	Vehicle refuelling appliance

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1 Introduction

1.1 Background

Natural gas (NG) offers several potential advantages as a lower carbon transportation fuel compared to gasoline, diesel, and other traditional fuels. These include:

- Lower GHG emissions
- Lower emissions of criteria air contaminants (and lower associated abatement costs)
- Opportunity for greater fuel diversification and thus advantages to expand security of supply (particularly with the lower cost of natural gas)
- Economic benefits in the form of industrial development and the creation of new employment opportunities.

The present report is an assessment of the potential use of natural gas as an alternative fuel across the transportation sector. This includes the on-road and off road, marine, rail, and indoor equipment sectors. The report has been prepared for the Fuels Policy and Programs (FPP) division of Natural Resources Canada (NRCan).

Factors driving the need for this assessment include:

- The Government of Canada's Copenhagen Accord Commitment to reduce GHG emissions by 17 percent below 2005 levels by 2020;
- The need to displace the use of carbon intensive fossil fuels (i.e. gasoline and diesel) and diversify the nation's energy supply;
- The need to improve overall air quality;
- Potential economic benefits.

The circumstances under which natural gas might successfully be used as an alternative fuel in Canada are discussed.

1.2 Objectives and Scope

The objectives of this study are:

- To explore and analyze the potential for the use of natural gas in support of the Government of Canada's policy objectives for the transportation sector.
- To conduct a study that includes research and information gathering to inform the development of a Canadian strategy for the use of natural gas in the transportation sector.
- To identify and explore other potential future applications for natural gas in the Canadian context within the transportation sector.

The work entailed four main components:

- A review of the lessons learned from programs and activities in Canada (at the federal and provincial levels) and internationally.
- A review of the current prospects for natural gas and natural gas vehicles in a variety of transportation applications – taking into account changes in the overall market for NG, advances in technology and other drivers.

- Identification of the technical, economic and achievable potential for NG in transportation applications, taking into account relative costs and benefits (market costs, non-market costs), as well as barriers and policy/program opportunities to overcome barriers.
- Consultation with key stakeholders to refine the analysis and findings.

1.3 Approach

1.3.1 Segments

Potentially all on-road and off-road vehicles can be driven on some form of natural gas fuel. However, a preliminary assessment of previous, existing and future market and technology trends in North America and more specifically in Canada and consultation with NGV industry stakeholders showed that the more promising NGV market segments are likely to consist of the following:

- Heavy duty and medium duty, including line haul trucking (fleets), return-to-base trucks, transit buses, refuse trucks
- Light duty fleets. Examples are taxis and courier services
- Marine vessels
- Rail (locomotive)
- Indoor industrial vehicles, including forklifts and ice re-surfacers.

These segments were selected to be included in the study of financial, environmental and achievable potentials.

Other segments of potential interest include surface mining applications and privately owned light duty vehicles. NGV application in mining relies mainly on the oil sands industry in Western Canada and other open pit mining activities which, overall, constitute a smaller potential compared to the other segments included in the present analysis. Privately owned passenger cars constitute a large share of light duty vehicles. However, the limited choice of NGV technology and vehicle models offered by Original Equipment Manufacturers (OEMs) in this area, as well as the expectation of fierce competition with the upcoming electric and plug-in-hybrid-electric passenger cars, ethanol and second generation biofuels make NG inroads in the passenger vehicle market potentially difficult.

1.3.2 Sources

The study relied on a variety of information sources, including:

- Information provided by NRCan on NGV background, government programs and reports
- Research on recent NGV activities, R&D projects, NG upstream and retail markets
- Published reports by a variety of international, US and Canadian agencies, including National Energy Board and International Energy Association
- Documentation and verbal communications with a variety of industry stakeholders and experts, including the Canadian Natural Gas Vehicle Alliance (CNGVA), various CNGVA, members, International Association for Natural Gas Vehicles (IANGV), and NGV technology suppliers
- Marbek in-house knowledge in the area of policies and programs, alternative fuels policies and programs, NGV technologies and natural gas upstream, distribution and retail infrastructure

1.3.3 Analysis

Our methods included a variety of qualitative and quantitative approaches:

- **Policies and Programs History.** We analyzed Canadian federal and provincial policies and programs, and well as international programs and policies including USA, South Asia, South America and Europe, and analyzed the lessons learned.
- **Technology Trends.** We assessed technological maturity and commercial viability of various NGV technologies, NG fuel availability including supplies, distribution and pricing schemes.
- **Financial Analysis.** We used spreadsheet financial analysis to determine the economic viability of each NGV market segment. For the analysis of fuel supply investments, we looked at prices in the retail market place and considered a breakdown of cost components to calculate the residual profit/markup. For the analysis of vehicle acquisitions, we used information on incremental capital costs, fuel use and savings to determine payback, net present value and the internal rate of return. We also conducted a sensitivity analysis to develop a variety of cost curves – illustrating the variability of payback periods for NGVs under different conditions.
- **Environmental Analysis.** We used GHGenius version 3.16 for light duty vehicle emissions, and version 3.17 for medium and heavy duty, marine and rail freight. Version 3.17 has the functional unit of tonne-km and is adapted to freight applications.
- **Achievable Scenarios.** We used the information on the financial viability, the environmental advantages and the barriers and potential solutions, along with our internal expertise and experience to develop scenarios describing both a baseline and a realistic but relatively ambitious achievable scenario for each market segment. Where applicable, this was done on a bottom-up basis looking at individual market segments and regions, which were then extrapolated to the rest of Canada. As the level of analysis is superficial, these should be considered illustrative scenarios only.
- **Policy Analysis.** Based on a barriers analysis, we identified the steps that needed to be taken to allow commercially available and financially viable opportunities to be realized. Based on our understanding of the policy and market context, we proposed typical government interventions that were likely to be needed to deliver the achievable scenarios. If necessary, we adjusted both the interventions and the scenarios to reflect a realistic view. Once again, this should be viewed as illustrative.
- **Fuel Displacement and GHG Reductions.** The achievable potential was used to calculate the fuel displacement and the corresponding GHG emission reductions. GHG emission reductions were calculated using emission factors obtained from Canada's GHG Inventory¹.

1.3.4 Consultations

In addition to the contacts undertaken for information collection (see sources above), further discussions were conducted with a small group of industry stakeholders. Draft versions of the key findings were provided and feedback was obtained from representatives of:

- Westport Innovations
- Gaz Metro
- Enbridge
- Encana
- Canadian Natural Gas Vehicle Alliance (CNGVA)

¹ National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990–2007, Environment Canada

1.4 Organization of the Report

This report is organized as follows:

- Section 1 gives an introduction to the study, including objectives and scope, a definition of NGV technology and market segments and the approach used to perform the study.
- Section 2 gives an overview of international and domestic NGV markets.
- Section 3 describes the history of important Canadian federal and provincial programs, as well as significant international programs. A summary of the lessons learned from these programs is given.
- Section 4 deals with natural gas fuel delivery for transportation use, including upstream supply, distribution infrastructure, retail and pricing. A brief description of biogas (bio-methane from landfill and agri-waste) application in transportation is included.
- Section 5 gives a summary of technological trends in NG vehicles for each segment.
- Section 6 explains the environmental impacts of using NG in transportation, including GHG and CAC emissions.
- Section 7 presents the financial analysis including scenarios, results, sensitivity analysis and implications.
- Section 8 gives a list of general and segment-specific market and non-market barriers to the development of a sustainable NGV market.
- Section 9 describes our assessment of the achievable potential in the context of various policy options for the promotion of NGVs. This includes a description of the scenarios, along with the associated fuel displacement and GHG emission reductions.
- Section 10 presents the conclusions of the study.

2 Overview of International and Domestic NGV Markets

2.1 Global Markets

Historically, prospects for NG as a transportation fuel have to some extent followed an inverse relationship with the price of oil. When the price of oil (and gasoline/diesel) rose in the late 70s and early 80s, markets for NG and NGVs appeared more promising. However, the extended period of low prices from the late 1980s to the early 2000s, made it difficult for NG to compete as a transportation fuel. Even with higher prices for traditional fuels, NG prospects have not been as promising because (until recently) of supply concerns and because other fuels or other technologies have appeared more promising.

As of December 2009, there were more than 11 million NGVs on the roads worldwide². Globally, the use of natural gas as a road-transport fuel currently accounts for only 1% of total gas consumption. The global average growth rate in the number of NG vehicles between 2000 and 2009 has been 28.7%, with Asia-Pacific and North America ranking the highest and the lowest, with +50.9% and -0.1% growth rate respectively. This trend is expected to continue at an average rate of 3.7% per year to 2030, with most of the growth coming from non-OECD countries, which already account for most gas use for road transport.

Exhibit 1 shows the list of countries with more than 0.5 million NGVs, which consists of Pakistan, Argentina, Iran, Brazil, India, and Italy.

Exhibit 1 Natural gas vehicle statistics – countries with 0.5 million or more NGVs³

Rank	Country	Natural Gas Vehicles	Refuelling Stations	Year data received
1	Pakistan	2,400,000	3,105	2008
2	Argentina	1,807,186	1,851	2008
3	Iran	1,734,431	1,079	2008
4	Brazil	1,632,101	1,704	2008
5	India	725,000	520	2008
6	Italy	580,000	730	2008

The majority of natural gas vehicles worldwide are cars, but buses account for much of the consumption, and two- and three-wheelers powered by CNG are prominent in Pakistan, India and some Southeast Asian countries. In India, all public transport vehicles in New Delhi are required to be powered by CNG.

Most light-duty NGVs are converted gasoline-powered vehicles, though an increasing number of vehicles worldwide are being manufactured to run on CNG.

² International Association for Natural Gas Vehicles - IANGV

³ International Association for Natural Gas Vehicles – IANGV – December 2009.

In North America, interest in promoting NGVs is growing in the United States, driven by low prices and the perception that indigenous supplies are ample.

The potential exists for much faster growth in this sector, but it hinges on stronger policy action (on environmental and energy-security grounds) to promote investment in distribution infrastructure and switching by consumers to natural gas vehicles.

A summary on international NGV development activities is presented in Appendix A.

2.2 Canadian Market

In worldwide classification, Canada ranks 29th, with about 12,000 NGVs.⁴ This number includes 300 heavy-duty vehicles, 150 urban transit buses, 45 school buses, 9,450 light duty cars and trucks and 2,400 forklifts and ice-resurfacers. The total fuel use in all NGV markets in Canada was 1.9 PJ in 2007 (or 54.6 million litres of gasoline equivalent), down from 2.6 PJ in 1997.⁵

Medium and Heavy Duty Fleets

There are an estimated 300 heavy duty vehicles using CNG in Canada (LNG is not yet used as a transportation fuel in Canada). The heavy duty engine industry is located in the Vancouver, BC area and is largely represented by Cummins Westport and Westport Innovations. Cummins-Westport's ISL G engine has been integrated into products offered by 15 North American truck, bus, and specialty vehicle OEMs including Freightliner, Mack, and Peterbilt.⁶ Although there are few vehicles in Canada, there are currently 1,200 heavy duty engines in California and 18,000 in China manufactured by these two companies. The heavy duty engine market has a good potential growth overseas. However, the cost of key components such as LNG tanks, injectors and CNG tanks needs to come down for market to grow without incentives.

There are 150 urban transit buses in Canada. This market is in rapid decline due to the previous poor experience of transit companies that used the older technology. With recent technological advances at both domestic and global levels, the transit bus market is expected to have good a growth potential due to fairly high gas use and the possibility of central refuelling. Manufacturers such as Ontario Bus Industries, New Flyer and MCI have the capacity to supply CNG buses. However, there are barriers to overcome before market can be renewed in Canada. The main barriers are discussed in Section 8 of the report.

There are only 45 school buses in Canada. This market used to be large in the Prairies, but has lost to diesel competition in recent years. School buses are ideal for slow-fill, return to base situation but conversion cost must be reduced for the market to grow.

It should be noted that there could be a possible renewed interest in CNG as diesel emissions system costs rise to meet 2010 standards. On the other hand, there are only 12 private fleet stations left in Canada, including 2 serving transit buses.

⁴ Data obtained in December 2009.

⁵ (a) Statistics Canada, *Report on Energy Supply-Demand in Canada 1990–2007*, Ottawa, February 2009; (b) Natural Resources Canada, *Transportation End-Use Model*, Ottawa, August 2009.

⁶ From consultations with Cummins-Westport, March 2010

Light Duty Vehicles

The light duty market, including cars and trucks, has declined from 30,000 vehicles in the early 1990s to 9,450 currently. No OEM products are available in North America, except for the Honda Civic GX which is only available in the US market.

Several small to medium size upfitters are located in US, however there are no Qualified Vehicle Modifiers (QVM) serving OEMs in Canada. The conversion cost of light duty NGVs has been inflated by generous US incentives, which makes the market penetration of such vehicles difficult in Canada.

Heavier light trucks (8,500-10,000lb GVW) are increasingly diesel powered and have less potential for NGV.

There are only 72 public NG stations in Canada, which is down from 134 in 1997. There are 22 public refuelling stations in British Columbia, 12 in Alberta, 10 in Saskatchewan, 27 in Ontario and 1 in Quebec.

Industrial Indoor Vehicles

Industrial indoor vehicles currently have a small share of the market, with about 2,400 forklifts and several hundred ice-resurfacers. NG competes successfully with LPG for indoor warehousing and manufacturing markets and ice resurfacers are already largely NG powered. Some of the advantages of NG in indoor vehicles are: lower fuel cost, ease of conversion, improved indoor air quality, and suitability to the smaller end of the market (30-50HP engines). Additionally, the use of NG eliminates the need for swapping of batteries in electric vehicles or handling of heavy LPG tanks. One disadvantage with NG indoor vehicles is the limited OEM product availability. Another disadvantage is the limited number of vehicle refuelling appliances (VRAs). This number is estimated at 485 units currently in use.

It should be noted that there is no VRA manufacturing facility in Canada at the present time, since the only Canadian VRA manufacturer has gone out of business. However, this is expected to be a temporary situation, as a new owner is preparing to offer VRAs to the Canadian market. The global market for indoor industrial vehicles is largely dominated by Korean manufacturers. Among other OEMs and manufacturers, Toyota produces a factory-direct natural gas forklift. In Canada, Westport Innovations has recently started to produce natural gas engines for forklifts.

3 Program History and Lessons Learned

3.1 History and Current Programs

3.1.1 Canada – Federal

History

Over the years, the federal government has played an active role in setting up NGV codes and standards that govern vehicle conversions and station design and siting. At the same time, the implementation and enforcement of these codes and standards has principally been a provincial and local government concern. The federal government also assisted NGV technology and market readiness by providing technical performance data from demonstrations and safety testing, and by providing a federal view through the Canadian General Standards Board (CGSB) committees that produced vehicle and fuel standards. Key initiatives included:

- **Natural Gas Vehicle Grant Program (NGVGP).** The NGVGP was established in 1983. This was a \$25 million – 5 year grant program that offered up to \$500 per vehicle converted. Another program, Natural Gas Station Program (NGSP) offered up to \$50,000 towards the construction of private or public NGV fueling stations.
- **Federal R&D.** The federal government supported NGV technology research and development in the areas of NGV fuelling systems, injection technology, tank material technology, and manufacturing capacity development. Examples of successful results of this support include:
 - Commercial NG injection system by Ortech and GFI/Teleflex;
 - Dual fuel (NG/diesel) injection technology at the University of British Columbia
 - Founding of Westport Innovations
 - Lightweight carbon fibre wound storage tanks
 - Canadian NG transit bus manufacturing capacity development
- **Other R&D.**
 - Energy, Mines & Resources (EMR - the forerunner of NRCan) and the Ontario government also supported R,D&D of NGVs in the early 80's, including a new technology for NG injection for engines at the Ontario Research Foundation (ORF). ORF was privatized later to form Ortech, and was subsequently acquired by Bodycote.
 - Building on R&D support from the federal and BC governments, the University of BC Department of Mechanical Engineering developed bi-fuel NG/diesel fuel injection systems in early 1980's that were a leading clean technology. This technology was acquired by Westport Innovations in 1995 and is now being successfully marketed in major markets such as in California and several other US states, China, and some of the European countries such as Italy.
 - From 1986-1990, under the Enerdemo Program, EMR funded up to 36% of the \$975,000 NG/diesel demonstration project in BC.

- **Canada-US Cooperation.** The federal government entered into cooperation on technology demonstrations with California, US DOE and NYSEDA between 1983 to 1990. Canadian and US OEM vehicle programs during 1987-1993 supported development of factory-produced NGVs, e.g. the Chrysler minivan, which achieved Ultra Low Emission Vehicle (ULEV) status in the US; the federal government also supported the participation of GFI in the Ford Qualified Vehicle Modifier (QVM) program. This consisted of GFI converting Ford vehicles to NG, but with Ford selling and servicing the vehicles through its dealer network, as if they were factory-produced vehicles. In the 1996 model year, Chrysler and Ford between them offered a wide range of vehicles with a NG option, e.g., large sedan, a minivan, full size vans, and full size pick-up trucks.

Despite these efforts by the federal government and others, the NGV market did not prove to be sustainable. The deregulation of the NG industry influenced the NGV market significantly. A previous National Energy Policy (NEP) rule that NG prices would be pegged at 65% of the price of oil no longer held in the deregulating energy industry. In addition, the economics of NG for transportation became gradually less favourable as oil prices were gradually decreasing and stabilizing through the late 1980s and early 1990s.

3.1.2 *Canada – Provincial*

History

The Canada-Alberta accord was an important driver for the NGV market. In addition to funding the extension of NG pipelines in ON and QC, the program included incentives for market development, such as transportation. The Market Development Incentives Payments (MDIP) was funded from a special federal levy on AB gas producers. When the NG lateral pipeline program was terminated with the end of the National Energy Policy, \$35 million remained in the fund, which was held in escrow by the federal government. Following negotiations with AB, the remaining MDIP funds were to be used to continue funding NGV and station grants in provinces where AB gas was consumed, i.e. East of AB.

The Federal government cooperated with Ontario, Quebec, Saskatchewan, Alberta and British Columbia, through a liaison process with these provinces that had some incentives for NG (grants and fuel tax waivers). In the case of BC, there was a federally funded program outside of MDIP that worked to increase NG, depending on the availability of funds. Both the BC government and BC Gas contributed to this program by providing their own funding.

The Ontario government had a NGV research program during the early 1980s. It funded gaseous fuel projects, including the gaseous fuel injection system. The Ontario Ministry of Transportation (MTO), with support from EMR, pioneered NG as a fuel for transit buses with Ontario Bus Industries (OBI) in the early 80s and a number of municipal transit fleets bought these buses. Ontario and EMR funded R&D of compression equipment for the quick refuelling stations, which involved the compressor manufacturers. Two Canadian companies with federal research funding, certified and applied advanced high-pressure NG tanks. In the late 1980s, research focused on scaling-up the gaseous fuel injection technology for large engines so that buses and other HDVs could reliably and efficiently use NG instead of diesel.

Current Situation

Provincial incentives currently in place include sales tax relief measures in Ontario and BC. Both of these supports will be lost in 2010 when the provinces transition to the Harmonized Sales Tax (HST).

- Ontario currently offers \$1,000 PST rebate for light duty NGVs, as well as 100% PST rebate for NG transit and shuttle buses.
- BC currently offers \$1,000 social service tax exemption for light duty NGVs, and up to \$10,000 social service tax exemption for NG buses.

It is worth noting that there will be an uneven treatment of transportation fuels, with the transition to HST in BC, as conventional, higher carbon fuels (gasoline, diesel) will be exempt from the provincial portion of the HST while alternative, lower carbon fuels (natural gas, propane, hydrogen, electricity) will not be exempt.

The Ontario Ministry of Transportation (MTO) also has in place a Green Commercial Vehicle Program that provides 1/3 of the capital premium incentive funding to a maximum of \$15K for Class 3-7 commercial vehicles. This program is scheduled to run until March 2012, but may end sooner due to financial pressures.

Quebec has funding in place to support energy efficiency initiatives, which may in the future be made available for LNG truck activities (e.g., Robert Trucking).

3.1.3 *International*

A summary of the history and current initiatives in selected countries is included here. Additional details are provided in Appendix A. Selected highlights of these initiatives are given below.

United States

Like Canada, the U.S. has had a variety of initiatives and programs (both federal and state) but has had limited success in fostering a sustainable NGV market. Currently, a renewed effort is underway, with substantial incentives through a variety of means, including the Clean Cities program and the American Recovery and Reinvestment Act (ARRA).

Currently, a variety of incentives are available for NG fuel, vehicles, and infrastructure. Federal income tax credits are also available to offset the cost of each of these options. In addition, many states and air quality districts offer incentives, and some utilities offer preferential gas rates to customers with a small home refueling appliance sold under the name “Phill”. Key incentives and associated laws are listed in Exhibit 2.

Exhibit 2 Summary of US Incentives and Associated Laws

Incentive Type	Federal Law	Provision
Fuel	Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users, P.L. 109-59 (8/10/05) (SAFETEA LU)	Excise tax credit, paid from the General Revenue Fund, for an alt. fuel sold for use or used as a fuel to operate a motor vehicle. For NG, the credit is \$0.50 per gge ⁷ of CNG and \$0.50 per LNG. (Note: motor fuel excise tax rate for CNG/LNG is on parity with that for other motor fuels). Eligible entity if liable for reporting/paying the federal excise tax on the fuel or if a nonprofit tax-exempt entity that fuels on site.
Fuel	Emergency Economic Stabilization Act/Energy Improvement and Extension Act of 2008 P.L. 110-343 (10/3/08)	Section 204 amended the expiration date for the existing alternative fuel excise tax credit from September 30, 2009 to December 31, 2009.
Vehicle	Energy Policy Act of 2005, P.L. 109-58 (8/8/05)	A qualified alt. fuel motor vehicle tax credit is available for the purchase of a new, dedicated, or repowered/converted AFV ⁸ . It is for 50% of the incremental cost of the vehicle (if meets federal EPA or CARB emissions standards), plus an additional 30% if the vehicle meets certain tighter emission standards (e.g., EPA's Tier 2, Bin 2 standard for LDVs). These credits range from \$2,500 to \$32,000, depending on the size of the vehicle. The credit is effective on purchases made after December 31, 2005, and expires on December 31, 2010. In addition, (reduced) tax credits are also available for certain mix-fuel or dual-fuel vehicles having a GVWR ⁹ ** of more than 14,000 pounds. The vehicle must be capable of operating on a "combination of an alternative fuel and a petroleum-based fuel."
Infrastructure	Energy Policy Act of 2005, P.L. 109-58 (8/8/05)	Income tax credit available - 30% of the cost of NG refueling equipment, up to \$30,000 in the case of large stations and \$1,000 for home refueling. Effective on purchases placed in service after December 31, 2005, and expires on December 31, 2010 (extended by Emergency Economic Stabilization Act).
Infrastructure	American Recovery & Reinvestment Act of 2009, P.L. 111-5 (2/17/09)	This act increases the value of the credit for the purchase of equipment used to store and dispense qualified alt. fuels, placed in service during 2009 and 2010. The credit is \$50,000 or 50% of the cost for business and \$2,000 or 50% of the cost for home refueling.

Pakistan

Pakistan has the largest total number of NGV fleets in circulation for public transportation. Free market consumer price of CNG, Natural gas tariff for CNG linked to petrol, priority of natural gas connection for CNG, and exemption of import duty and sales tax on import of machinery and kits are examples of NGV policies in Pakistan.

⁷ Gallons of Gasoline Equivalent

⁸ Alternative Fuel Vehicle

⁹ Gross Vehicle Weight Rating

Argentina

Argentina is second only to Pakistan in the number of NGVs. The Government facilitated the installation of the equipment needed for service stations and created a program for several hundred taxis in Buenos Aires to convert to natural gas. The savings was enough to convince car owners to convert their vehicles, which in turn prompted more service stations to offer natural gas. A large portion of their public transportation system has also been converted to CNG, encouraged by government-enforced financial incentives.

Brazil

Brazil ranks third in the world for number of NGVs and for number of refuelling stations. Most of the NGVs now are aftermarket converted taxis or commercial MDVs.

Success factors in the growth of the NGV market have included: government incentives; sound regulation, standards and certification; good distribution infrastructure; competitive price of fuel; environmental performance¹⁰.

India

India provides a well known example of a mandate – the public bus system in Delhi, which is required to use CNG. In July 1998, the Supreme Court of India ordered the CNG program for Delhi. Government support was provided through further measures, such as: Sales tax exemption on conversion kits; Concessional custom duty on CNG conversion kits; Allotment of land for CNG stations and pipelines on priority basis; Banning old vehicles from registering in Delhi.

Europe

Gasoline in Europe sells for over \$8 per gallon (about 4.5 liters), therefore a government mandate to motivate conversion to alternative fuels is unnecessary. Nonetheless, financial incentives from the government to pay for as much as 75% of conversion costs, and environmental concerns provide further incentives among the European community. Italy has the largest number of CNG vehicles in Europe and is the 4th largest country in the world for CNG vehicles on the road. Germany, Poland and France are rapidly working to catch up with Italy.

3.2 Lessons Learned from Programs

Several lessons can be learned from the previous and existing programs implemented in Canada and around the world. These can be categorized as considerations regarding technology and markets.

In the area of NGV technology, the experience suggests that continuous efforts in development of NGV technology are vital to market success.

- Overall, fast-changing emission standards and dropping oil prices hurt NGV in the mid-1990s.

¹⁰ <http://www.iangv.org/tools-resources/ngvs-by-country/brazil.html>

<http://www.ngvglobal.com/brazils-sulgas-offers-incentives-to-boost-natural-gas-conversions-0629>

R.Fernandes, IBP NGV Committee, Brazil NGVs: Beyond a million, NGV-2006, November 7 –9 Cairo, Egypt

- NGV R&D did not keep pace with the emission standards, resulting in increased costs of compliance and OEMs pulling out of the market.
- NGV did not adapt to the emerging vehicle and engine technology
- Huge OEM and government effort should be made to improve new vehicle GHG and CAC emissions
- Natural CAC advantage of NG diminished with new rounds of emission standards
- More drivetrain competition emerged in all markets - hybrids, PHEVs, diesel, GDI and variants

In the area of market development, the following lessons can be drawn:

- Fuel availability, fuel price differential and stability were shown to be key drivers in the development of NGV market.
- Lack of competition, low market volume and high US incentives led to high prices for NG vehicles which depresses market interest in Canada.
- New markets can be primed by well planned technology demonstrations with suppliers and users.
- Momentum takes time to build. Success is achieved by signing one customer (and other stakeholders) at a time.
- Transit markets are well suited for NGV, but rebuilding this market will take time and support from governments

More specific lessons learned by different stakeholders are summarized in sections 3.2.1 and 3.2.2 below.

3.2.1 Governments

From the policies and programs that have been implemented domestically and globally, it can be concluded that governments' role can assist initial market development where there is an economic potential for NGV.

Key lessons are:

- Government should support industry's lead with programs that reduce (not eliminate) risk, including information programs
- Incentives and subsidies should be temporary, not built into the long term cost structure
- NGV programs work best in regions where federal support is provided along with strong provincial and utility support
- Vehicle grants are best provided at point of sale (e.g. by gas utility) or within 30 days by federal program
- Government fleet conversion provides an example for other fleets and supports fueling infrastructure
- It could be difficult to support NGV growth when oil prices drop to low levels or where there is uncertainty about gas supply and price
- Mandates used in some countries don't work well in absence of a business case
- Even though NGV technology is fairly mature, there is still a need for ongoing government R&D support

3.2.2 Others

Fuel Providers

A detailed review of the past activities by fuel suppliers including utility companies and their market partners shows that:

- Turnkey projects can ease market entry for fleets
- Visible marketing campaign and financing programs are required to overcome the lack of awareness of NGV opportunity
- LDV fleet growth must be supported by adequate public station availability which can be enhanced by means of (a) securing public access to private stations; and (b) a targeted home refueling strategy
- Provide NG fuel price can be stabilized by hedging, long term contracts and other strategies
- It is crucial to coordinate the rollout of fueling infrastructure with vehicle fleet growth
- Developing training for conversion and maintenance industry should be assisted.

Technology Providers

The NGV technology providers have also learned from their earlier phases of technology development. Some of this learning can be summarized below:

- NGV technologies need to perform seamlessly with current sophisticated automotive systems
- Challenge of scaling up production and geographical reach
- Component costs controlled by others have a large impact on economics of NGV, e.g. fibre-wound tanks, LNG tanks, dual fuel injectors
- Continuous R&D programs are required with focus on
 - Fuel injection and combustion
 - Emission control systems
 - Component and system integration
 - Tank material and fuel storage technologies

NGV Champions

The impact of the Pickens Plan in US is an example of how a business or political champion could have a significant impact on the development of NGV market.

After spending more than 35 years traveling to Washington asking presidents and legislators to formulate a comprehensive energy plan for America while U.S. oil imports climbed from 24 percent to almost 70 percent, in July 2008 Pickens decided to take his case to the American public. He bankrolled a national ad and media blitz campaign outlining how the United States was exporting an alarming portion of its wealth to pay for its addiction to foreign oil and detailing a Pickens Plan that offered alternative energy solutions. He conducted continuous town meetings¹¹ across the country and solicited millions of "soldiers" for his plan on a Pickens Plan website.

¹¹ <http://www.boonepickens.com/helping/default.asp>

4 Fuel Supply

This section provides an overview of current and projected market trends regarding natural gas as a commodity, as well as the fuel supply industry, including distribution infrastructure, as well components of pricing of natural gas fuels at the retail level.

4.1 Upstream Supply and Demand

Natural gas can be extracted from conventional reserves that in many cases are found together with oil. This type of natural gas is in widespread production worldwide today. There are other types of natural gas reserves that have been historically less attractive due to economic or technical difficulties. These include shale gas, tight gas and coal-bed methane.

4.1.1 Current Outlook Reports

A variety of industry reports and forecasts indicate that conventional NG resources are in decline in North America. Currently available forecast reports from Canadian, US and international agencies charged with monitoring the supply and demand of energy commodities indicate that there will be a growing supply of unconventional gas in Canada, but not yet sufficient to offset the reduction in conventional supply.

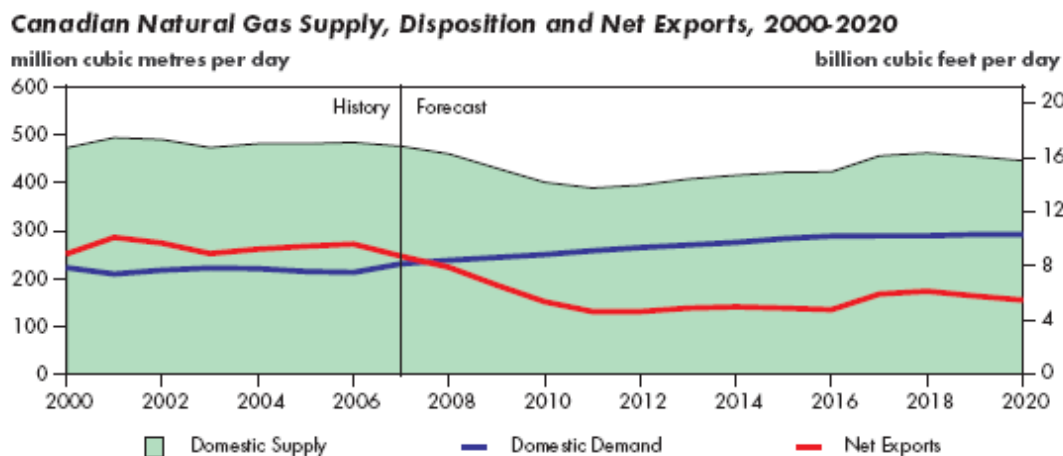
The National Energy Board (NEB) in Canada reports the following in its Reference Case 2009:

As of 2007, Canadian and US drilling continued to diverge: US recorded a 4% increase and is increasingly targeting unconventional gas plays, including shale gas in Texas, Arkansas, and Oklahoma, and coal bed methane in the US Rockies while Canada recorded a dramatic 25% decline. Historical trends show that NG production had been in decline up to 2008 but is now rising in the US. In Canada the production trend will bottom-out at 14.5 bcf/day in 2014, and then will begin to climb again to 16 bcf/day by 2020. The North American demand is expected to grow at approximately 1.5% per year. The average growth rate in Canada will be 2.3%. Overall, the North American supply is expected to increase by about 20% by 2020¹².

The NEB reference case is shown in Exhibit 3.

¹² National Energy Board – Reference Case 2009

Exhibit 3 Natural gas demand forecast in Canada (from National Energy Board 2009 Reference Case)

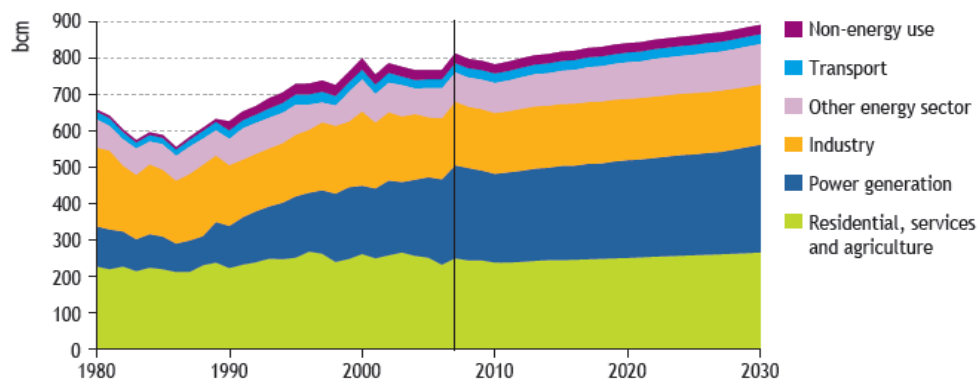


The World Energy Outlook (WEO) 2009 published by the International Energy Agency (IEA), natural gas production shows a significant increase in shale gas production in the US, but no significant overall increase in supply in North America.

The WEO 2009 also indicates that Canada has followed a very similar trend to that in the United States, with an increasing proportion of unconventional gas being developed as conventional basins mature. Several producing and service companies operate in both countries, using largely the same technologies, and knowledge is transferred rapidly from one market to the other. Production in Canada is projected to decline gradually, by 15 bcm between 2008 and 2030 in the Reference Scenario; it falls by a more marked 26 bcm in the 450 Scenario which assumes a coordinated global effort is in place to reduce GHG emissions.

The IEA's Natural Gas supply and demand outlook 2007-2030¹³ for North America for total natural gas supplies including both conventional and unconventional (shale and tight gas, and coal bed methane) is illustrated in Exhibit 4 and Exhibit 5 respectively. The Canadian natural gas supply and demand forecast from WEO 2009 published data is presented in Exhibit 6.

Exhibit 4 Natural gas demand forecast in North America (from World Energy Outlook 2009)



¹³ Source: World Energy Outlook 2009, © OECD/ IEA 2009 – The graph corresponds to the OECD/IEA Reference Scenario (i.e. In the absence of drastic government action to reduce GHG emissions)

Exhibit 5 Natural gas production forecast in North America (from World Energy Outlook 2009)

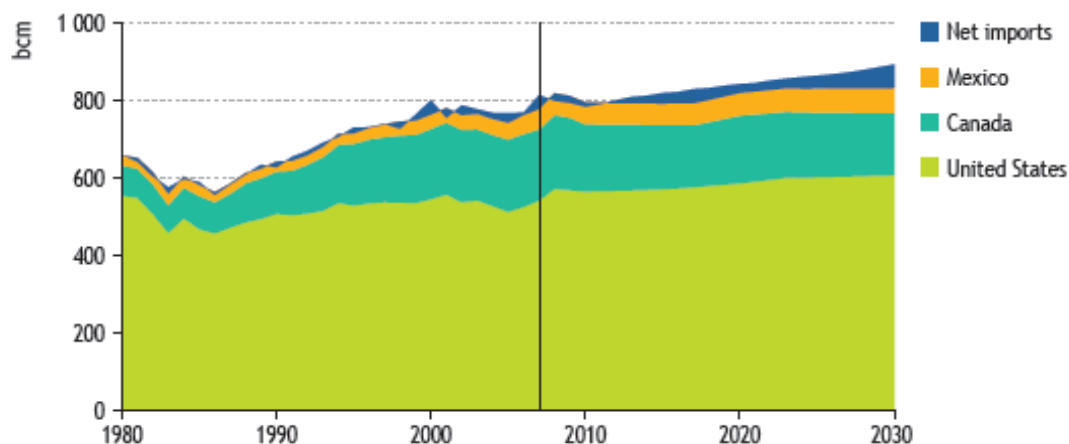
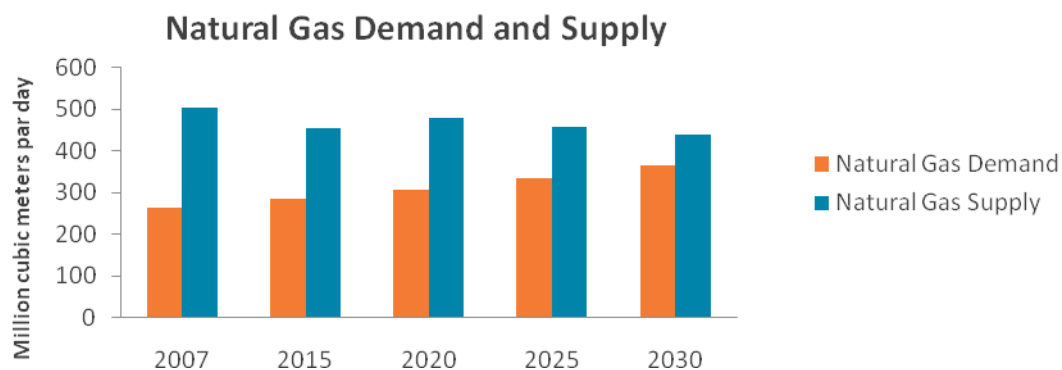


Exhibit 6 Natural gas demand forecast in Canada (from World Energy Outlook 2009)



4.1.2 Recent Events

Development of Shale Gas Reserves

Recent deployment of new technologies such as horizontal drilling and hydraulic fracturing to economically access unconventional gas resources, appear to be changing the market in a fundamental way. Among the various types of NG resources in North America, shale gas appears to be particularly promising. New discoveries and extraction activities related to shale gas plays are reported on a weekly, if not daily basis, indicating the fast growth dynamics in this NG segment.

Notwithstanding the official reports, the increasing pace of development of unconventional gas reserves (and shale gas in particular) is leading many industry observers to conclude that the natural gas market is no longer "supply-constrained". There is much optimism that North American reserves will be sufficient to meet the demand for 100 years or longer and expectations are that development of US supplies will reduce the level of Canadian exports, making more gas available in this country. Much of these dynamics are not yet well documented or reflected in the official (albeit recent) energy outlook reports.

Canadian shale gas plays that are being evaluated currently include:

- **Montney Formation** – The production of natural gas from horizontal shale gas wells in the Montney of northeast B.C. has risen from zero in 2005 to 10.7 106 cubic metres per day (376 million cubic feet per day) and is expected to continue rising. As of July 2009, 234 horizontal wells were producing from the Montney shale. Exploration companies have spent more than \$2 billion since 2005 to acquire rights in the Montney Formation from the B.C. government.
- **Horn River Basin** - Wells in this basin in northeast British Columbia are prolific and produce an average initial flow rate of 230,000 cubic metres per day (8 million cubic feet per day) with the top wells ranking amongst the most productive drilled in Western Canada last year. Exploration companies have spent over \$2 billion to acquire resource rights in this basin.
- **Colorado Group** - The Colorado Group of southern Alberta and Saskatchewan have been producing natural gas from shale for over 100 years. Because of poor rock conditions and the risk of caving in the wellbore, only vertical wells are planned in the Colorado shale.
- **Utica Group** - These shales, located between Montréal and Quebec City near the Appalachian Mountain front, have an increased potential for natural fractures. The potential for shale gas from the Utica Group is still in the early evaluation stages.
- **Horton Bluff Group** - While still in the early evaluation stage, two vertical wells drilled in New Brunswick have flowed 4,200 cubic metres per day (0.15 million cubic feet per day) after undergoing small fractures.

Mapping of shale plays is difficult due to the heterogeneity of the rock formations, their extremely low permeability and uncertainty as to the volume of reservoir that can be connected to a production well.

Environmental Considerations

There are environmental issues with shale gas extraction that could affect the viability of recovery efforts. These include concerns about the effects that shale gas drilling has on the watershed, land-use footprint and a potential increase in lifecycle GHG emissions, among others.

Drilling and hydraulically fracturing wells can be water-intensive procedures. In the U.S., where water is extensively used in hydraulic fracturing, producers developing the Barnett Shale in Texas used one per cent of all the water consumed in the Fort Worth basin in 2007. Water that has been used to fracture a shale gas well can contain chemicals and additives so it is never allowed to enter the watershed. Typically, it is disposed of by injecting it deep below the earth's surface into rock formations, which is a common practice in Western Canada and strictly regulated by provincial authorities.

The land-use footprint of shale gas development is not expected to be much greater than conventional operations because advances in horizontal drilling allow for up to ten or more wells to be drilled from the same wellsite.

A number of factors can affect the relative GHG footprint of shale gas:

- **Leakage of methane.** Normally, field production, gathering and cleaning, separation of water or oil from associated gas, and the extraction of natural gas liquids reduce gross natural gas production by about 6 to 10 percent. There is no indication that this would be any different for shale gas.

- Fuel and energy use. The carbon footprint of a horizontal well exceeds that of a typical vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions. On the other hand, developing equivalent amounts of natural gas resources requires two to three times more vertical wells than horizontals, for example, extracting 20,000 MMcf of natural gas may require 10 horizontal wells, but 25 to 30 verticals.¹⁴
- CO₂ releases. While not all shale gas contains significant amounts of CO₂, the potential growth in carbon emissions from some shale gas is being addressed with proposals for carbon capture and sequestration.

On a per MMBtu basis, total GHG emissions from natural gas produced from shale formations are currently considered to be similar to those of natural gas from conventional sources. Still, it is very early to draw definitive conclusions regarding the potential impact of these developments on the environment.¹⁵

Movements opposing hydraulic fracturing are growing in NY State which is sitting at the edge of the enormous Marcellus shale play. The state has imposed a moratorium on drilling until it ensures the development won't threaten water sources. Also, a U.S. congressional committee is investigating drilling firms, including two Calgary companies, over concerns that their drilling for shale gas deposits may be contaminating water supplies.

Currently, shale gas producers have to comply with the same regulations as conventional natural gas producers, and provincial governments in Canada have well-established regulations in this area. This study did not examine whether provincial regulations in Canada regarding natural gas production are more stringent than those of the United States.

4.2 Fuel Delivery

In transportation applications, natural gas is used either as compressed natural gas (CNG) or liquefied natural gas (LNG).

- CNG is made by compressing natural gas to less than 1% of its volume at normal temperature and pressure. It is stored in steel or fibre-wound cylinders at high pressures (3000 psi) and used directly in spark-ignited or diesel engines.
- LNG is made by condensing natural gas at temperatures of approximately -162°C. The liquefaction reduces the volume by a factor of more than 2 compared to CNG and eliminates the need for high pressures. The LNG is stored on a vehicle in a double-walled stainless steel tank and it is vaporized before injection into the cylinders of a gasoline or diesel engine.

There is also potential to establish L-CNG stations that can dispense both LNG and CNG for a range of vehicles.

¹⁴ Shale-Deposited Natural Gas: A Review of Potential, May 2009, California Energy Commission

¹⁵ National Energy Board – Understanding Shale Gas, November 2009

4.2.1 *Components and Players*

Natural gas is typically piped from upstream supplies through standard transmission and distribution networks but may also be sourced from import terminals. Key components may include transmission pipelines, distribution networks, storage, and LNG import terminals.

- Transmission pipelines include pipelines and compressor stations to transport the gas across large distances from upstream supply areas to key market hubs.
- Distribution networks include the networks of piping, stations, services and meters to distribute the gas to end-users. These are owned and operated by Local Distribution Companies (LDCs) who are typically regulated as monopoly utilities.
- Storage includes depleted gas or oil reservoirs, or engineered storage caverns mined in salt formations. Being able to store gas gives market participants the ability to have a physical hedge (insurance) against price volatility and to store excess gas in the summer months for use during the winter heating season.
- LNG import terminals involve specially constructed vessels delivering imports of LNG from overseas LNG plants to shipping terminals and regasification plants in North America. The only operating terminal in Canada is the Canaport LNG Terminal in Saint John, NB.

LNG infrastructure includes liquefaction plants and stations.

- LNG Plants require special cooling systems and cryogenic tanks to maintain low temperatures. Plants range in size from 50,000 to 1 million litres/day, cost from \$5-50 million. LNG Plants could obtain gas from distribution networks, or directly from transmission pipelines or import terminals.
- LNG stations typically include storage containers, dispensers, control systems and meters. Some stations may also include CNG dispensers. The typical cost for an LNG station is about \$2.5 million.
- Plants and stations may or may not be co-located. In the latter case, tanker trucks are required to deliver the LNG to the stations.

CNG infrastructure includes a range of slow or fast fill station designs, typically consisting of compressor, storage and dispensing equipment.

- High pressure fast fill stations can supply up to 25-50 LDE per minute and meet the needs of up to 100 transit buses for a cost of \$2-3 million.
- Smaller units could supply a fleet of 10 MDVs for approximately \$250,000 with fast fill, or about \$150,000 for overnight slow fill.
- Vehicle Refuelling Appliances can be slow fill or fast fill. They range in price from \$35,000 for fast fill quad dispenser (for 10 LDV / forklifts) to \$6,000-7,000 for slow fill dispenser (for single LDV / ice resurfacer).

4.2.2 *Current Fuel Supply*

Currently, the only form of NG fuel used in Canada is CNG. CNG is available from approximately 72 public and 12 private stations. Public stations are typically operated by traditional fuel retailers (e.g. Shell). The gas is supplied by LDCs, and the compression, storage and dispensing equipment is either owned or provided by a service provider (e.g. Clean Energy). Fleets may or may not have private fuel supply (transit bus applications usually have a private supply).

LNG is not currently used for transportation in Canada, however Gaz Métropolitain, Union Gas and Terasen Gas have small LNG plants, with associated LNG storage facilities. Existing public stations can provide refuelling for heavy vehicles, but space and onsite compression capabilities

need to be considered. Similarly, the compatibility of dispenser designs may also be an issue, as there are different versions and not all pairs of vehicle fuel receptors – fuel dispensers are compatible.

4.2.3 Future Fuel Supply

Possible players include upstream companies (e.g. Encana), transmission companies (e.g. Transcanada), LDCs (e.g. Enbridge, Gaz Metro), service providers (e.g. Clean Energy, Gaz Metro), fuel retailers (e.g. Shell), or fleet owners (e.g. municipalities, trucking firms, large retailers).

So far, Terasen has obtained regulatory approval to sell excess LNG from its TGI Tilbury facility (located in Delta, BC) for transportation use as a five year pilot and Gaz Metro is looking to offer LNG or CNG for fleet, rail and marine applications^{16,17}.

Encana has proposed the construction of several LNG plants and stations along the Quebec City – Windsor corridor and in Alberta and BC. However the business model for this initiative is not yet clear, nor is it clear who would build, own and operate the plants and the retail infrastructure.

For regulated transmission or distribution utilities, a key consideration is whether or not regulators (i.e. provincial energy/utility boards and commissions) would allow investments in fuelling infrastructure to be rate based. Ratebasing the investments would allow a predictable return and would mitigate key risks but, to be effective, it would likely depend on cross-subsidization from residential and commercial customers, which would be difficult for regulators to approve without strong signals from governments. If the business case were strong enough, some utilities might consider making the investments on the non-regulated sides of their business. This would likely require a higher level of confidence in the timing and scale of the transportation market.

4.2.4 Pricing

In general, the main factors that affect price volatility are:¹⁸

- Storage levels: high storage levels promote lower prices and vice versa (short term effect)
- Crude oil influence (longer term effect) due to fuel switching at industrial and power generation facilities
- Regional supply and demand: natural gas prices are the lowest in Alberta and the Rockies
- Limitations in distribution capacity
- Speculations based on economic forecasts of commodity prices.

Commodity Prices

The main factors responsible for recent (2007-2008) natural gas commodity prices were the dramatic increase in US natural gas production driving prices down and volatility in the price of crude oil driving prices both up and down. The average intra-Alberta NG price for 2000-2007

¹⁶ British Columbia Utilities Commission – Order number G-65-09

¹⁷ From consultations with Gaz Metropolitain, March 2010.

¹⁸ “What Drives Natural Gas Prices?”, Stephen P. A. Brown and Mine K. Yücel (Research Department, Federal Reserve Bank of Dallas), The Energy Journal, Volume 29, Number 2, 2008, International Association for Energy Economics

period was \$6.07/GJ, with several peaks over \$10. Moving forward, prices expected to remain in the range of \$6/GJ.

Retail Prices

There is currently no market for transportation LNG in Canada and very small one for CNG. The lack of completion and the fact that fuel prices are tied to regulated quarterly price adjustments leads to higher prices than necessary.

- Current prices for CNG range from \$0.60 to \$0.80/litre of diesel equivalent (DLE). \$0.65/DLE is considered to be a representative price for initial stages of an expanding marketplace.
- Prices for LNG in California are in the range of C\$0.60/DLE. Canadian prices for LNG could be lower initially as suppliers make use of existing excess LNG capacity but would eventually also be expected to be in the neighbourhood of \$0.65/DLE

As noted in Exhibit 7 and Exhibit 8, at the expected prices, returns should be highly attractive for either public or private stations (these are based on a commodity price of \$5.50/GJ).

The financial analysis for NG vehicle purchases is presented separately in Section 7, followed by a discussion of non-financial barriers in Section 8.

Exhibit 7 LNG Price Components

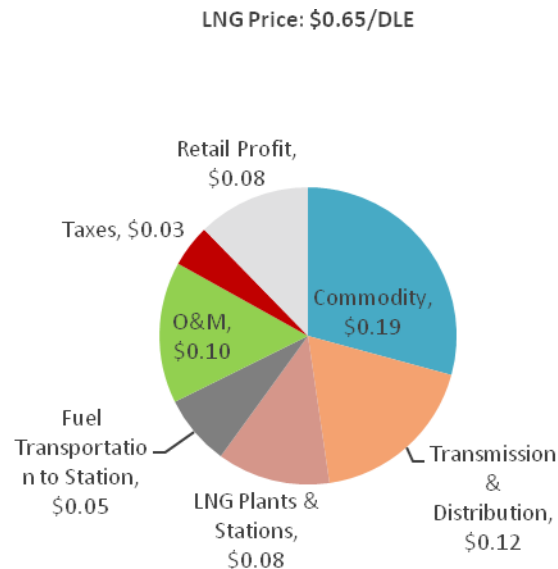
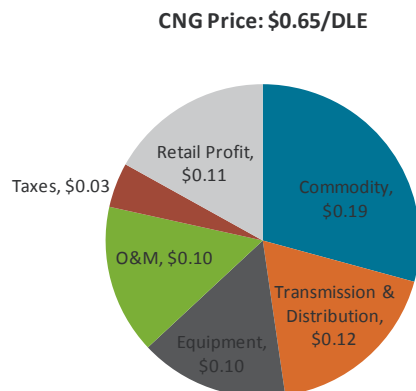


Exhibit 8 CNG Price Components



4.3 Biogas

Renewable natural gas (RNG) or biogas as commonly referred to is another type of methane-based gas with similar properties to natural gas that can be used as transportation fuel.

Sources of biogas are mainly landfills, sewage and animal/agri-waste. Based on the process type, biogas can be divided into the following: Bio gas produced by anaerobic digestion, contains mainly CH₄ and CO₂; Landfill gas collected from landfills, treated to remove trace contaminants, composition similar to biogas; and Synthetic Natural Gas (SNG), contains mainly CH₄, produced via biomass gasification followed by methanation.

In addition to methane the following compounds might be present in biogas: water vapour, carbon dioxide, hydrogen sulphide, siloxane, aromatic compounds, air (oxygen, nitrogen), halogenic compounds (chlorides, fluorides).

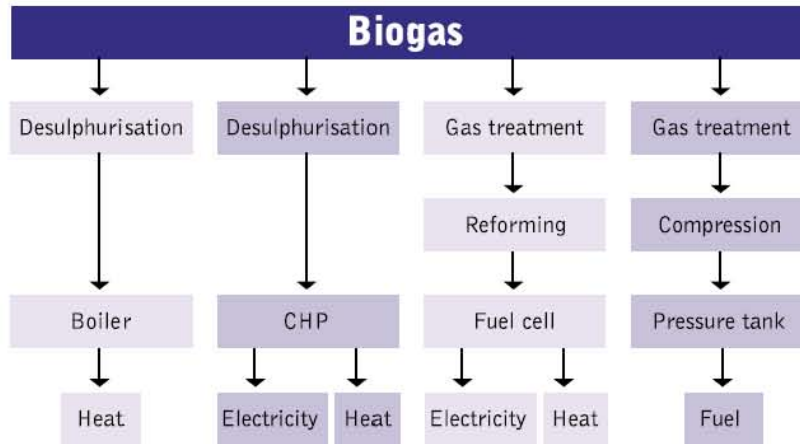
Cleaned biogas can be converted to CNG or LNG through similar processes, or can be introduced to utilities natural gas pipelines to serve distant clients, hence eliminating storage issues.

The cost of biogas depends of the level of processing. Use of biogas in transportation requires a much higher quality than biogas one used in boilers. Current costs are \$7-8 per GJ assuming the existing collection pipes are already in place.

The current costs of biogas are not competitive with natural gas but could be competitive with diesel/gasoline.

Biogas can be used in various end uses to produce heat and/or electricity. Cleaning, treatment and upgrading requirements depend on the type of end use.

Exhibit 9 Different Processing Paths for Biogas¹⁹



¹⁹ “Biogas Production and Utilisation”, International Energy Agency (IEA), 2005

5 Technology Trends

5.1 Heavy and Medium Duty Vehicles

Heavy and medium duty vehicles use two types of engine technologies: Spark Ignited (SI) engines and High Pressure Direct Injection (HPDI) engines. Both types are commercially available. HDVs are supplied with either LNG or CNG fuel tanks. LNG is more suitable for longer haul vehicles but lack of stations is the main impediment to general market growth.

Spark Ignited Engines

SI engines are used in return to base refuse trucks, transit and school buses. SI engines typically use CNG.

The main suppliers of SI engines are Cummins Westport, Doosan Infracore, Emissions Solutions (ESI), Iveco, Daimler, Volvo, MAN, Scania, Shanghai Diesel, Weichai Petersen and Hyundai.

Cummins Westport is based in Vancouver, BC. It produces heavy duty natural gas SI engines that are sold worldwide. Doosan Infracore and Emissions Solutions (ESI) produce spark ignited engines for North America. Iveco, Daimler, Volvo, MAN and Scania supply SI engines in Europe, Asia and South America, as does Doosan, Cummins Westport, Shanghai Diesel, Weichai Petersen, Hyundai. There is also dual fuel CNG/LNG but only as a non-certified aftermarket retrofit (by Hardstaff, Clean Air Power)²⁰.

SI engines have a typical additional cost of \$50,000 compared to diesel heavy duty engines which consists of \$10,000 engine cost and \$40,000 integration costs, including tanks. A HDV using natural gas fuel is about 10% less efficient than one using diesel fuel.

The most recent ISL G engine manufactured by Cummins-Westport operates on either CNG or LNG. Rated at 320 hp and 1,000 lb-ft of torque, the ISL G is compliant with 2010 emission standards without the use of selective catalytic reduction (SCR) or a diesel particulate filter (DPF). CNG and LNG fuel tanks can be configured to suit customer applications and range requirements.²¹

High Pressure Direct Injection Engines

High Pressure Direct Injection (HPDI) engine technology is used in Class 8 trucks.

BC-based Westport Innovations adapts Cummins engines for HPDI, adding dual fuel injectors (diesel pilot and NG main fuel charge) and other equipment. Cummins –Westport has sold over 20,000 ISL G 8.9 Litre engines worldwide. Cummins – Westport and Westport Innovations supply about 15 OEMs worldwide. MAN and Iveco sell heavy duty natural gas engines in the European market.

HPDI engines have the same efficiency as diesel engines and can be driven up to 1000km on one fuel charge. The engines typically cost \$70,000 more than diesel engines and the LNG

²⁰ From consultations with Westport, March 2010.

²¹ “Kenworth Expands Natural Gas Truck Line with T440 Powered by ISL G”, The Globe and Mail, March 24, 2010

tanks cost an additional \$10,000 each (line-Haul HDVs typically require 2 LNG tanks). Westport produces up to 2400 engines per year in Vancouver, mainly for export to the US and China.

5.2 Light Duty Vehicles

Natural gas Light Duty Vehicle (LDV) technology is commercially available but its availability in North America is extremely limited. Honda is the only OEM to offer a natural gas LDV in the North American market, with the CNG-driven Civic. It has limited sales (700 per year) in the US only.

In the absence of significant OEM offerings, another source of NG LDVs is the OEM-approved upfitting of NG technology. Fuel metering/injection technologies are well developed for low volume LDVs and there are many North American conversion suppliers, including BAF, IMPCO, Baytech, FuelTek, ECO Fuel Systems. Ford and GM are each planning to produce one natural gas ready engine for the North American upfitting market, but the timing and availability remains uncertain. Even in the upfitting market, the number of engine/vehicle combinations for light van and pickup truck markets is limited. Suppliers (non-OEM) have difficulty in introducing more makes/models due to technical, regulatory and financial barriers and lack of OEM support. Therefore, an increased market volume is difficult to support with current supplier industry. The lack of a sufficient number of Qualified Vehicle Modifiers (QVMs), has led to uncertified kits and installations sold sometime through Internet causing safety and quality concerns.

Storage tank cost, weight and size is a challenge for LDVs, especially as the vehicles are likely to get smaller over the next decade, in part to reduce GHG emissions. Thus low pressure storage technology will be needed, leading to conformable tanks. The NG technology will also need to adapt to smaller vehicle platforms, turbo-downsized engines, variable valve control, etc.

The price increment is typically around \$6,500 with respect to gasoline-driven models. Fiat and Volvo offer NG cars in Europe at much lower prices. In US, an EPA certified pick-up truck or panel van cost an additional \$14,000 to \$18,000 compared to a gasoline-driven truck. The lack of competition and the availability of generous US incentives are leading causes of excessive price mark-ups. The LDV market would benefit from increased competition, especially among the OEMs (Fiat, Volvo, etc.)

5.3 Marine

Natural gas marine technology is commercialized. Marine diesel engines are available that can burn NG with pilot diesel injection, with seamless fuel switching (NG/Diesel/HFO). Companies such as MAN and Wärtsilä manufacture large displacement HPDI engines for the large ship market.

The preferred NG fuel for marine application is LNG. LNG tanks need to be integrated into new vessel design; hence, additional design costs and construction cost increments are involved. These typically amount to approximately \$100,000 per vessel for design and \$5 million per vessel for construction.

Some ships may idle a long time during which they use diesel. Therefore, an anti-idle strategy is needed to avoid more diesel fuel being used at idle compared to cruise. The fuel consumption ratio is currently about 36% diesel-64% NG during idling and 4 diesel-96% gas NG during cruising.

5.4 Rail

Natural gas locomotive technology is NOT commercialized. However, it has been demonstrated that the common diesel or diesel-electric technology can be adapted to Westport's HPDI technology. Demonstrations have occurred in the US in the past that showed the feasibility of integrating NG to locomotive engines. There are additional design costs and construction cost increment to be borne in order to adapt and optimize NG technology in rail applications.

LNG is the preferred NG fuel for rail applications. It is especially well suited to high-load short-distance operations such as ore or coal hauling. Good examples of such applications are found in the Australian iron ore industry.

In order to provide enough fuel supply, LNG tanks need to be integrated into trains or railcars. LNG railcars are already available. In line haul trains, these railcars need to be hauled over large distance, causing feasibility issues with the LNG technology.

In rail applications, engine idling is very common. The current NGV technology uses diesel piloting during idling which reduces the benefits of NG fuel. The higher use of diesel at idle (36%) and low fuel use in rail yard operations require further technology improvements.

Even though the NG locomotive technology is not mature, in 2001, the Napa Valley Railroad and the Napa Valley Wine Train in California undertook the conversion of one locomotive to CNG, starting with 60 percent natural gas and 40 percent diesel fuel mixture. By early 2008, the conversion to compressed natural gas was 100 percent.²²

There is a serious interest in NG for rail in Canada, but projects could take a long time to realize.²³

5.5 Indoor Equipment

Indoor equipment suited to natural gas fuel includes forklifts and recreational equipment such as ice resurfacers. These vehicles run typically on propane or electricity. There is a growing trend in converting propane forklifts to natural gas using aftermarket conversion kits.

Among engine manufacturers, Westport has recently started to produce 2.4 litre and 2.0 litre LPG and CNG engines for forklifts through its joint venture partner Juniper Engines Inc.

Korean manufacturers are dominant in the global market for natural gas driven forklift engines. Toyota also offers a factory-direct natural gas forklift

Indoor equipment is usually serviced by private VRAs. FuelMaker manufactured VRAs in Canada until 2009. However, with the purchase of FuelMaker assets by Italian-based Fuel System Solutions (through its subsidiary IMPCO), Canadian manufacturing ceased and shortages of parts and services for existing VRA units in use in Canada have been a problem. This situation is expected to improve by Q3 2010²⁴. The deployment of alternatives to the current VRA choice

²² <http://winetrain.com/ontrack/news-rail-yard>

²³ Communications with Westport, March 2010.

²⁴ From consultations with Westport and CNGVA, March 2010.

would be helpful to ensure the continued development of the off-road market²⁵. One option is higher cost refueling stations which may be affordable for larger forklift fleets.

The benefits of using natural gas to power indoor equipment include:

- Improved air quality resulting in better health and safety of employees;
- Safer than propane alternatives since the refueling process does not require lifting of heavy tanks;
- Ease of refueling using VRA overnight or between uses;
- Natural gas units are lighter than electric alternatives, which can require facility retrofits; and
- Lower cost of natural gas results in a good return on investment.

²⁵ From consultations with Westport, March 2010.

6 Environmental Analysis

6.1 Greenhouse Gas (GHG) Emissions

This section provides a comparison of GHG emissions for conventional vehicles and NGVs. Results are provided for heavy, medium and light duty, refuse trucks, marine and rail. GHGenius 3.16 was used for light duty vehicles. For HDV, MDV, marine and rail segments, the freight emission calculation capability in GHGenius version 3.17 was used. This version has the functional unit of tonne-km (i.e., the movement of one tonne of goods one kilometre) which is a better reference for transportation systems used to move goods.

The following factors were included in the calculations of the lifecycle emissions:

- Vehicle operation
- Carbon in end-use fuel from CO₂ in air
- Net Vehicle Operation
- Fuel dispensing
- Fuel distribution and storage
- Fuel production
- Feedstock transmission
- Feedstock recovery
- Land-use changes, cultivation
- Fertilizer manufacture
- Gas leaks and flares
- CO₂, H₂S removed from NG
- Vehicle materials, assembly

For each segment the results are illustrated in two forms. First, the emissions from the base fuel used in the vehicle are compared with the replacement NG fuel (CNG, LNG, or both, if applicable). Then, the percentage change by using the NG fuel compared with the base fuel is noted.

The results are shown in Exhibit 10 through to Exhibit 16. Overall, lifecycle GHG reductions of 15-25%, depending on the end use, are obtained for NG fuel. The most significant reductions are obtained in the HDV, MDV, and LDV segments, which show reductions above 20%. As noted in Exhibit 13, biogas as a renewable fuel, has the benefit of much lower GHG emissions than non-renewable natural gas.

Exhibit 10 GHG emissions calculated for heavy duty trucks (23% reduction for LNG in comparison with diesel)

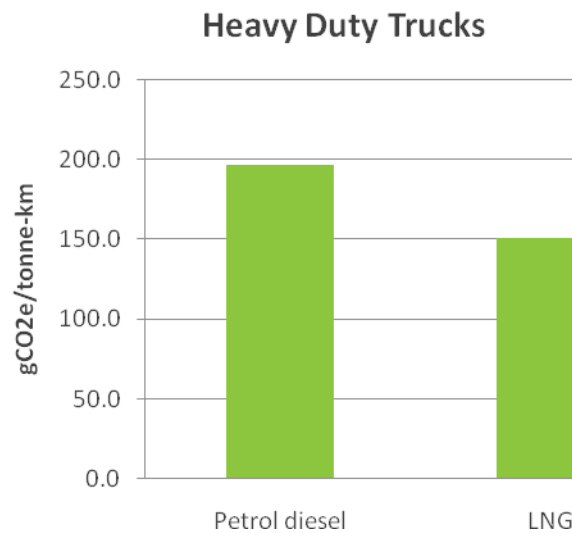


Exhibit 11 GHG emissions calculated for medium duty trucks (19% decrease for CNG, 23% decrease for LNG in comparison with diesel)

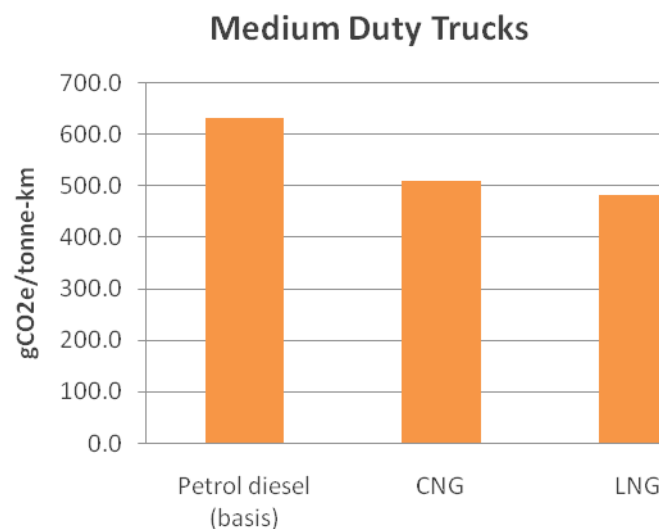


Exhibit 12 GHG emissions calculated for light duty vehicles (23% decrease for CNG in comparison with gasoline)

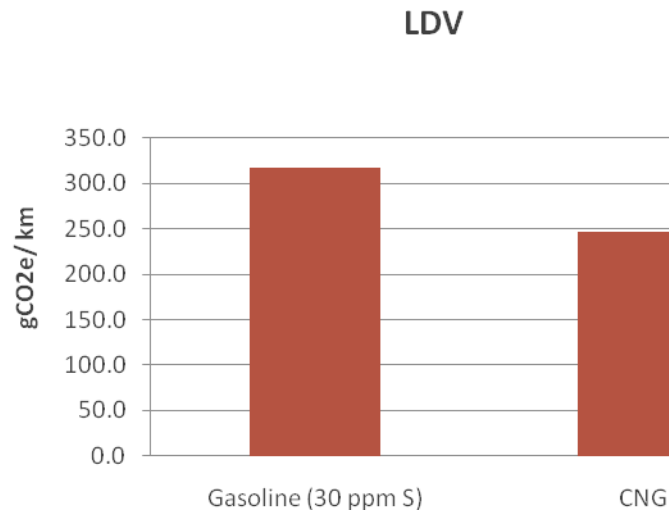


Exhibit 13 GHG emissions calculated for refuse trucks (19% decrease for CNG, 82% decrease for wood-based biogas, 88% decrease for landfill gas in comparison with diesel)

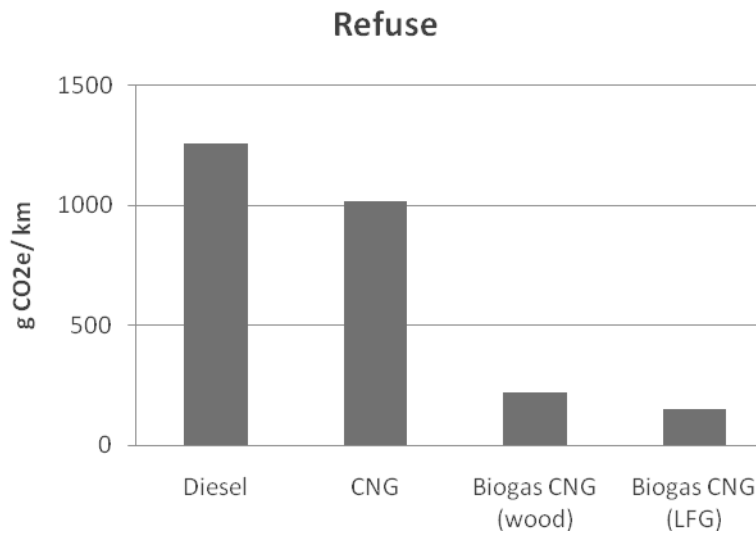


Exhibit 14 GHG emissions calculated for marine – Liquids and bulk freight (16% decrease for LNG in comparison with heavy fuel oil)

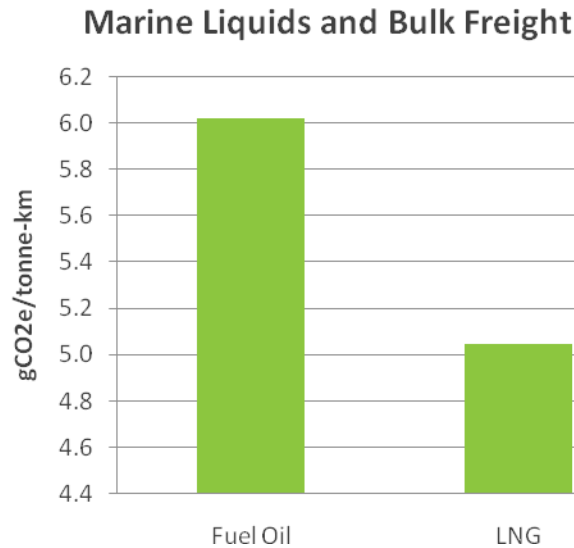


Exhibit 15 GHG emissions calculated for marine – General cargo and containers (18% decrease for LNG in comparison with marine diesel)

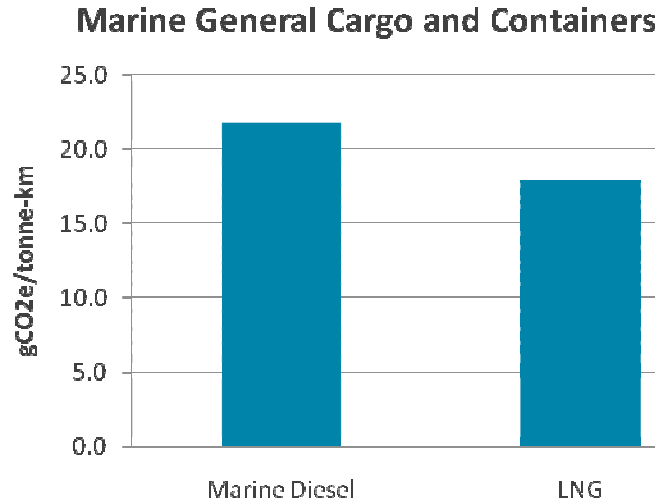
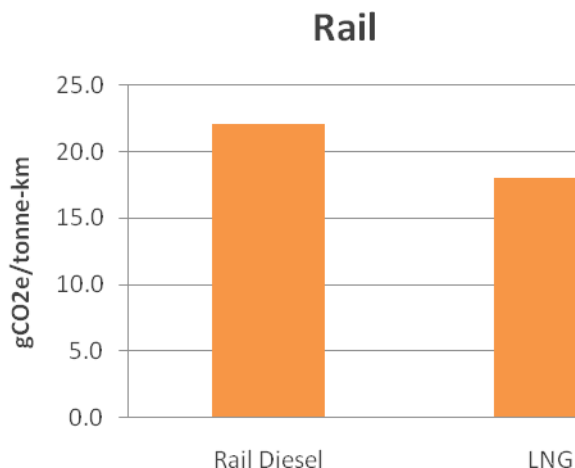


Exhibit 16 GHG emissions calculated for rail freight (19% decrease for LNG in comparison with rail diesel)



Criteria Air Contaminant (CAC) Emissions

The implications for CAC emissions vary by market segment:

- **HDV/MDV.** Natural gas has had a long-standing advantage in producing fewer emissions of a variety of CACs than diesel vehicles. Although HDV diesel exhaust will be cleaner because of 2010 standards, NG still has an advantage in Particulate Matter (PM) emissions over diesel as diesel particulate has more potentially carcinogenic content than NG. Tractors are able to meet 2010 CAC standards more easily than diesel vehicles, with less maintenance to emission control equipment due to lower engine-out PM and NOx emissions.
- **Marine and Rail.** NOx and PM emissions benefits from low sulphur gas displacing heavy fuel oil and marine diesel are likely to be particularly important for commuter trains and emission control areas in marine applications. For marine, conversion to NG would mean that the vessels could easily meet new CAC standards for environmentally sensitive regions around ports and Great Lakes. Significant fuel cost savings possible as low sulphur diesel would be largely replaced by NG.
- **Indoor Equipment.** Indoor air quality improves by using NG in forklifts and ice-resurfacers.

NG vehicles may have advantage over other technologies in meeting the fixed cap for tailpipe methane emissions.

New diesel emission control systems are costly (\$8-9K for SCR system plus operating costs). School bus operators in the US, having been subjected to DPF retrofit programs, are balking at further SCR additions to their vehicles, and are leaning to the idea of switching to simpler natural gas fuelling.

7 Financial Analysis

In this Section, the financial aspects of NGV purchase decisions are analyzed (note: the financial analysis of fuelling infrastructure investments was presented previously in Section 4). Financial viability is characterized in terms of simple payback, net present value (using a 10% discount rate), and internal rate of return. The NPV is based on the life of vehicle, engine or tanks, whichever is longest.

Viability is assessed for a variety of end-use natural gas vehicle fleet application, including several medium and heavy duty vehicles scenarios, light duty vehicles, marine vessels, and indoor equipment (note: viability is not assessed for rail because the technology is not commercially available).

Capital cost assumptions are based on the analyses provided in Section 5. Other assumptions are based on information collected from industry stakeholders and experts.²⁶ The following fuel prices assumptions are used (note that these are the same prices that were noted in our market assessment and used to calculate the viability of fuelling infrastructure investments):

- Diesel: \$0.95/L
- Gasoline: \$1.00/L
- LNG: \$0.65/DLE
- CNG: \$0.65/DLE
- Propane: \$0.70/L

For each application, a sensitivity analysis is performed. Multiple curves based on variations in fleet energy consumption (litres of fuel consumed) or capital cost increment are provided on the same graph. The cost curves are presented for each fleet application, showing capital investment payback based on fuel retail price differentials (natural gas/gasoline or diesel) (y-axis) and time (years) (x-axis).

It should be noted that GHG credits could add 1-3 cents incremental benefits/DLE but these credits were not included in the analysis.

7.1 Financial Scenarios

Eight Scenarios based on commercially available options were considered. These are described in Exhibit 17.

²⁶ Note: the analysis assumes that operating costs (other than fuel) are the same for NG and conventional vehicles. The new ISL G engine introduced by Cummins-Westport in March 2010 could add further NG savings by eliminating the need for the use of selective catalytic reduction (SCR) or diesel particulate filter (DPF).

Exhibit 17 Financial Scenarios for NGV Segments

Scenario 1 – HDV line haul (e.g. Robert) using LNG fuel	- Capital Cost Increment \$90,000 - Life of engine: 5 years - Life of tanks: 10 years - Annual Fuel Consumption 95,000 litres - Annual Fuel Savings: \$27,000
Scenario 2 – HDV return to base truck (e.g. Molson) using LNG fuel	- Capital Cost Increment \$70,000 - Life of engine: 5 years - Life of tanks: 10 years - Annual Fuel Consumption 60,000 litres - Annual Fuel Savings: \$17,550
Scenario 3 – Transit bus using CNG	- Capital Cost Increment \$45,000 - Life: 10 years - Annual Fuel Consumption 40,000 litres - Annual Fuel Savings: \$10,800
Scenario 4 – Refuse Truck using CNG	- Capital Cost Increment: \$50,000 - Life: 8 years - Annual Fuel Consumption: 28,500 litres - Annual Fuel Savings: \$7,700
Scenario 5 – LDV using CNG	- Capital Cost Increment \$8,000 - Life: 8 years - Annual Fuel Consumption: 5,000 litres - Annual Fuel Savings: \$2,100
Scenario 6 – Marine takers using LNG	- Capital Cost Increment: \$5.1m - Life: 30 years - Annual Fuel Consumption: 3.9m litres - Annual Fuel Savings: \$1.1m
Scenario 7 – Forklifts using CNG	- Capital Cost Increment: \$5,000 - Life: 8 years - Annual Fuel Consumption: 7,200 litres - Annual Fuel Savings: \$2,650
Scenario 8 – Ice resurfacers using CNG	- Capital Cost Increment: \$7,000 - Life: 12 years - Annual Fuel Consumption: 3,600 litres - Annual Fuel Savings: \$1,325

7.2 Results

Results are shown in Exhibit 18 through Exhibit 20.

Exhibit 18 Financial Viability Results

Market Segment / Scenario	Capital Investment	Payback (years)	NPV	IRR
HDV line Haul	\$90,000	3.3	\$48,140	22.4%
HDV RTB	\$70,000	4.0	\$9,613	13.5%
Transit Bus	\$45,000	4.2	\$37,146	22.9%
Refuse Truck	\$50,000	6.5	-\$8,948	4.9%
LDV	\$8,000	3.8	\$3,203	20.2%
Marine - Lakers	\$5,100,000	4.6	\$5,378,015	21.7%
Forklift	\$5,000	1.9	\$7,115	44.1%
Ice Resurfacer	\$7,000	5.3	\$503	11.5%

Exhibit 19 Simple Payback Results

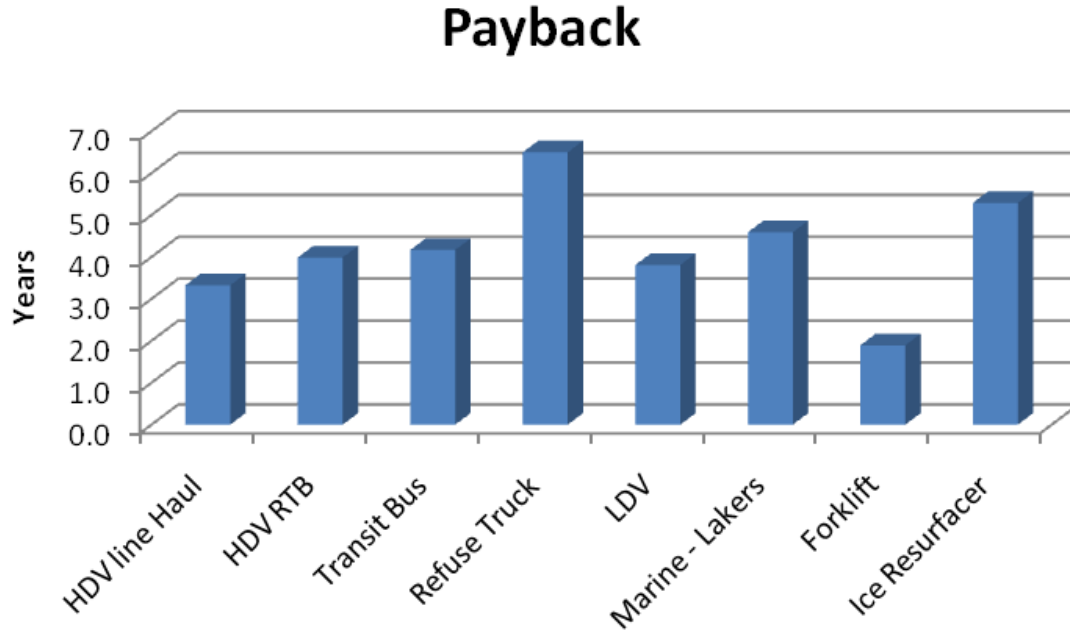
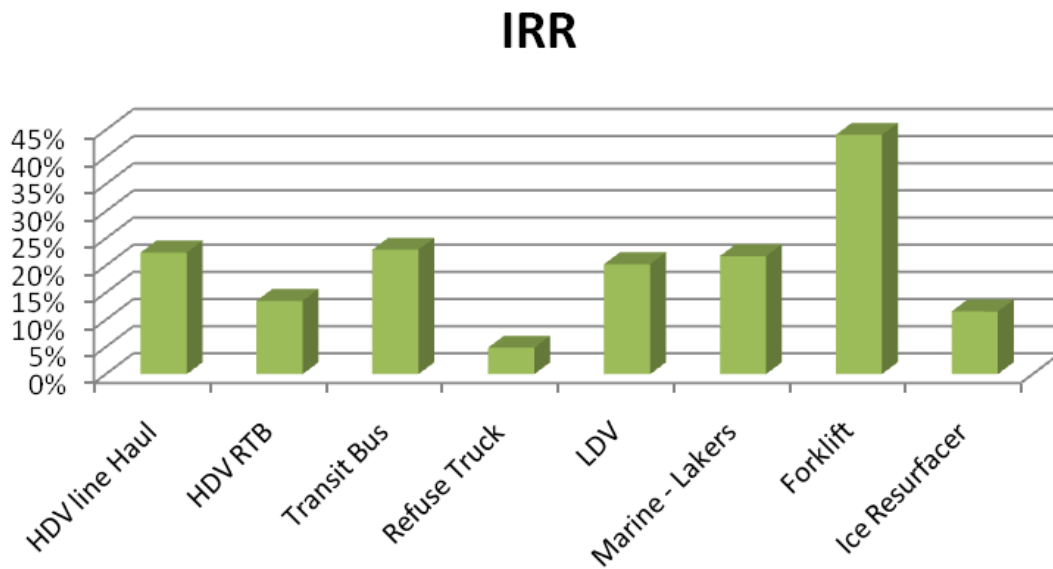


Exhibit 20 Internal Rate of Return Results



7.3 Sensitivity Analysis

Exhibit 21 through Exhibit 24 illustrates the variability of payback to various assumptions concerning capital cost increment, price differential and fuel consumption.

Exhibit 21 HDV/MDV Cost Curves

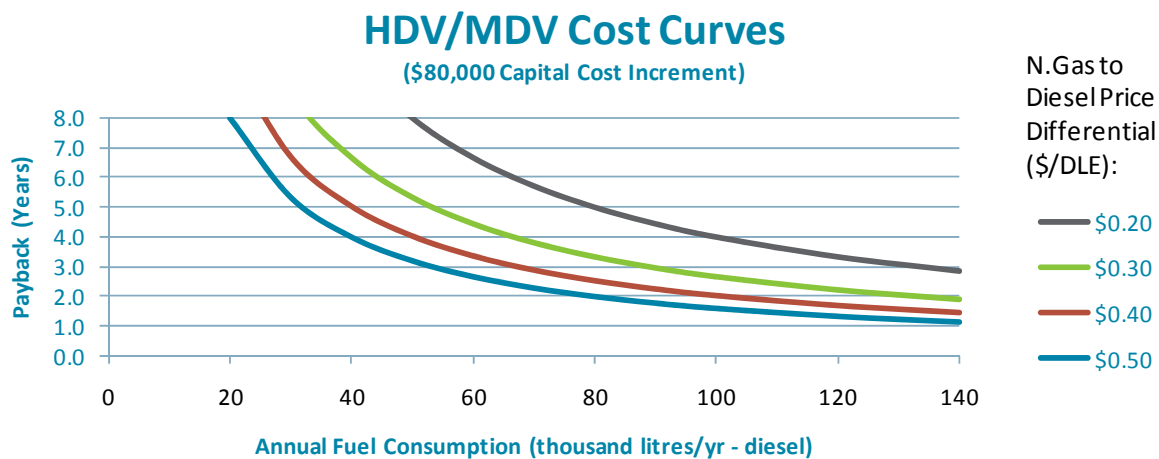


Exhibit 22 Refuse Truck Cost Curves

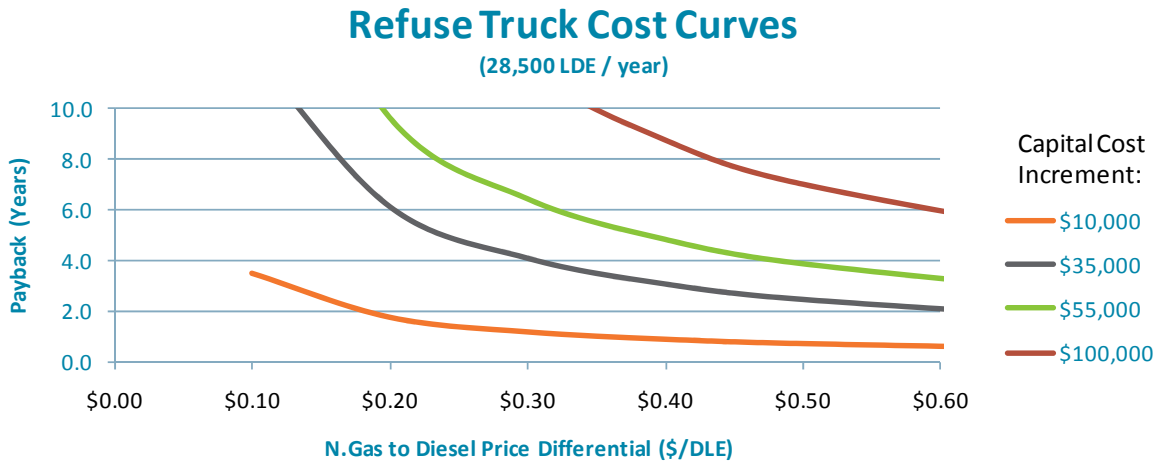


Exhibit 23 LDV

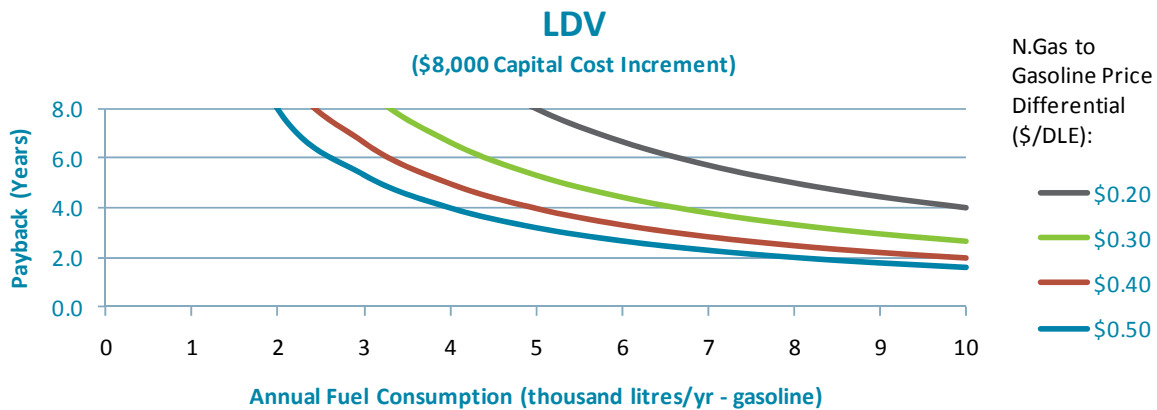
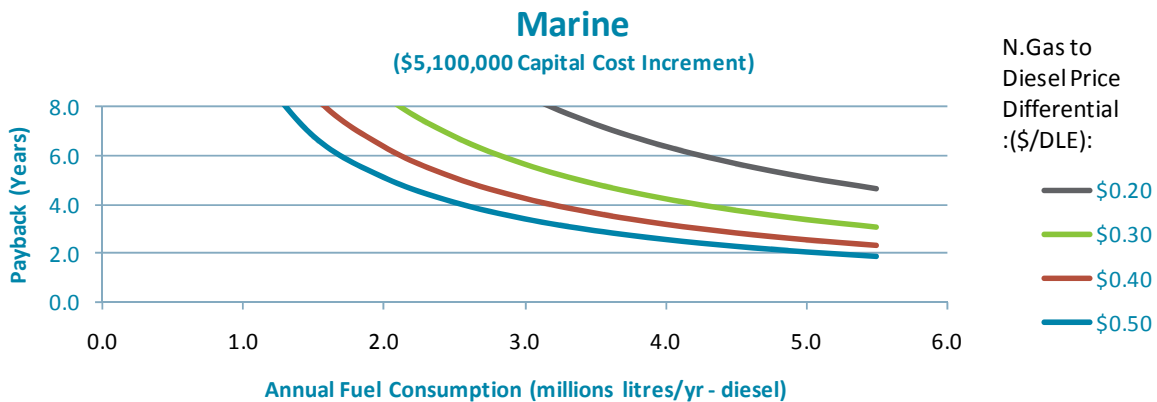


Exhibit 24 Marine



7.4 Implications

The financial analysis indicates that all segments except refuse truck are economically viable, provided that fuel is available at the assumed retail price. Other observations include:

- The forklift segment offers the best return, almost 45%.
- Line haul, transit bus, LDV and marine segments offer attractive returns, in the range of 20%. Because of the large sums involved, the marine scenario is particularly attractive in terms of the absolute dollars.
- The Return-to-Base HDV scenario and the ice resurfacer scenario are only marginally viable, in the range of 10-15% return.
- The refuse truck segment could be financially viable if capital cost increment could be reduced, say by \$15,000.

Although financial viability is an important determinant of the achievable potential, several of these segments/scenarios have other important advantages that could improve their prospects. For example, the environmental advantages of NGVs were noted in Section 6. In the context of indoor equipment, these environmental advantages translate into health advantages which can be overriding. In the case of refuse trucks, municipal interest in the GHG reduction advantages of biogas and the fact that refuse fleets are often under municipal control provides an attractive combination.²⁷

²⁷ From consultations with Westport and CNGVA

8 Barriers and Solutions

The review of the history of NGV development in Canada and lessons learned from the current and existing programs in other jurisdictions reveal that several barriers have prevented the development of a sustainable NGV market. These are both market and non-market barriers. Before any policy and programs can be designed to support the NGV market, it is important to identify these barriers and ways of overcoming them.

In this study we have divided these barriers into general and segment-specific barriers. These are presented in Exhibit 25 through Exhibit 31.

8.1 General

Exhibit 25 lists general market barriers that apply to all segments, along with possible ways to overcome them. Overlaid on these barriers is a general lack of understanding and confidence among a variety of stakeholders. Overcoming this will require a comprehensive communications strategy – potential elements of which are presented in Exhibit 25.

Exhibit 25 General Market Barriers for all NGV Segments

Barrier Type	General Barriers for all End-Use Segments	Ways of Overcoming
Market	Chicken and egg dilemma (vehicles & stations)	Simultaneous development of end use technology and fuel distribution and retail infrastructure
Market	Concern about availability of fuel/refuelling stations	Large upstream NG suppliers entering early into retail market, fuel suppliers marketing directly to end-users
Market	Limited range (related to concern of insufficient/not optimally located refuelling stations)	Target return to base fleets
Market	Concern regarding price fluctuations of the fuel	Long term federal and provincial deals with NG suppliers
Market	Limited choice of vehicles and engines for CNG and LNG	Facilitating vehicle imports, business incentives for the development of new NG vehicle plants
Market	Lengthy delivery times for vehicles (and parts)	Increase number of suppliers (competition)
Market	Increased maintenance costs for vehicles (Need for training mechanics and periodic high-pressure storage tank testing)	Financial support to cover the cost of training mechanics and acquiring tools. Some cost reductions come from possible longer oil change cycle with NG and extended engine rebuild intervals (engine rebuild does not apply to LDV or Indoor).
Market	Insufficient manufacturing and aftermarket conversion capacity, non-certified converters	Negotiate supply arrangements
Market	Defuelling systems (for maintenance work)	Training programs specifically offered /run/ subsidized by government, technical improvements

The markets where there has been negative experience with either technology and/or payback with NGVs could benefit from the following communications strategies:

Transit market. Transit managers and provincial departments of transportation could be made aware of the following:

- greatly improved Canadian technologies that are assembled by Canadian bus manufacturers and used successfully in the US;
- Improved economics of NG buses as gas prices remain low and oil prices are stabilizing above \$80/bbl.

The communications strategy should be coordinated with engine manufacturers, bus manufacturers and gas utilities. Venues include the Canadian Urban Transit Association (CUTA) annual conference (speakers, exhibits, articles) as well as visits to bus operations. Demonstration buses could be loaned to selected fleets (successful method in the past) and maintenance and operation data from successful operations in US should be provided to confirm economics.

Indoor forklift market. This market is at some risk with the previous experience on the only refueling equipment manufacturer (FuelMaker) being interrupted due to bankruptcy and new management. Discussions should occur with new owners of the technology to determine availability in Canadian market. Also, alternative low-cost refueling packages should be investigated with other suppliers so their availability can be communicated to forklift fleet users through articles and visits by participating gas utilities. Initiative should be led by gas utilities.

LNG trucking. This is an important new market which needs to be supported by a communications strategy in Ontario-Quebec and Alberta-BC. The initial objective is to increase awareness of the option and the economics for certain types of operation. The communications strategy should be coordinated with engine manufacturers and gas utilities/suppliers. Possible avenues include: using truck exhibitions and rodeos, articles in fleet management media, etc. The GHG reduction opportunity should be highlighted for larger fleets and shippers who have a growing interest in this topic.

Exhibit 26 lists general non-market barriers that apply to all segments, along with possible ways to overcome them.

Exhibit 26 General Non-market Barriers for all NGV Segments

Barrier Type	General Barriers for all End-Use Segments - Continued	Ways of Overcoming
Non-Market	Lack of interest/commitment from retailers – in terms of ability to outfit and fuel NGVs	Vehicle orders and incentives. Financing plans
Non-Market	Planning, zoning, code enforcement, permitting, and start-up issues with the installation of new LNG/ LCNG fuelling stations	Facilitating permitting procedure, expediting the permitting process, training programs specifically offered /run/ subsidized by government
Non-Market	Lingering perceptions of early technology performance (e.g. buses)	Marketing to public, educating end-users , low cost NG fuel, early adoption by government fleets, public transit and other public end-uses to demonstrate that the technology works
Non-Market	Lack of interest/commitment from some utilities – in terms of lack of marketing resources (including staff), no financing or incentives, etc.	Large upstream NG suppliers entering early into retail market to create competition, stable NG prices and reliable technology
Non-Market	Increased training requirements for mechanics – cost/time barrier to fleets that would have to train mechanics in multiple technologies/systems	Training programs specifically offered /run/ subsidized by government
Non-Market	Different regulations/requirements (permits) for the garages (e.g., venting and sensors)	Provision of technical information and turnkey solutions

8.2 Heavy and Medium Duty Vehicles

Exhibit 27 lists barriers that apply to the heavy and medium duty segments, along with possible ways to overcome them.

Exhibit 27 Barriers in the Heavy and Medium Duty Segment

End-Use Segment	Sub-Segment	Barrier Type	Barriers	Ways of Overcoming
HDV / MDV	All	Market	High cost of LNG tanks (although the financial analysis incorporates this incremental cost, it does not consider/deal with the initial barrier of up-front capital financing)	R&D investments on advanced materials and tank manufacturing technology for NG tanks
		Market	Limited choice of engines and suppliers	Increase NGV uptake to level that attracts larger suppliers. Facilitating vehicle imports, business incentives for the development of new NG vehicle plants
		Market	Limited range (therefore limited routes)	Return to base options (route redesign)
		Non-Market	If vehicles have weight restrictions – would have to decrease cargo, passengers, etc. because of weight of cylinders	R&D investments on advanced material technology for NG tanks, return to base options

8.3 Light Duty Vehicles

Exhibit 28 lists barriers that apply to the light duty segment, along with possible ways to overcome them.

Exhibit 28 Barriers in the Light Duty Segment

End-Use Segment	Sub-Segment	Barrier Type	Barriers	Ways of Overcoming
LDV	Fleets	Market	Availability of vehicles (OEM) / choice of models – with respect to fleets, smaller vehicles would not be available	Vehicle imports
		Non-Market	Perceived risk of vehicle reliability	Public education, availability of subsidized training programs for mechanics, Manufacturers directly marketing to public, early adoption of NG vehicles in government fleets
		Market	Additional cost of vehicle (capital and maintenance)	GHG regulations, purchase incentives
		Market	Payback improves with more mileage	Focus on fleets in the short term that have significantly greater annual mileage than personal vehicles
		Market	Tank location and size – the tanks tend to use up valuable trunk space – furthermore, the trend for taxi vehicles is toward smaller cars (e.g., Camry size) and there would not be as much room on them for the tanks	R&D investments on advanced material technology for NG tanks to increase the capacity, thus reducing size, use of multiple tanks

8.4 Marine

Exhibit 29 lists barriers that apply to the marine segment, along with possible ways to overcome them.

Exhibit 29 Barriers in the Marine Segment

End-Use Segment	Sub-Segment	Type of Barrier	Barriers	Ways of Overcoming
Marine		Market	Big investment to change ships and/or propulsion systems – would need a ~ 20 year LNG supply guarantee	NG price stability, reliable storage technology
		Market	Storage / limited range? Space limitations on board (particularly relevant for retrofit).	Use of multiple tanks

8.5 Rail

Exhibit 30 lists barriers that apply to the rail segment, along with possible ways to overcome them.

Exhibit 30 Barriers in the Rail Segment

End-Use Segment	Sub-Segment	Type of Barrier	Barriers	Ways of Overcoming
Rail		Market	No OEM offerings for powertrains	
		Market	Traditionally use dual fuel engines already (run on NG or diesel with diesel injection for both)	Novel NG fuel delivery system to reduce or eliminate diesel
		Market	Some trains do a lot of idling and use more diesel when idling – currently this is a technical barrier	Novel NG fuel delivery system to reduce diesel at idle

8.6 Indoor

Exhibit 31 lists barriers that apply to the indoor segment, along with possible ways to overcome them.

Exhibit 31 Barriers in the Indoor Segment

End-Use Segment	Sub-Segment	Type of Barrier	Barriers	Ways of Overcoming
	All	Market	Market constrained with one supplier only	Facilitate partnership between potential suppliers and end users to increase competition in the VRA market

9 Achievable Potential

Determining the achievable potential involves consideration of the technical potential and financial assessment, as well as the barriers and potential solutions. Scenarios must consider practical limitations on how quickly the market can change, as well as limits to what governments and other players can do to overcome non-market barriers. At the same time, it is important not to let scenarios be constrained by an artificial attachment to a business as usual approach and consider how effective policy instruments might unleash the technical, environmental and economic potential revealed in our analysis.

The process involved three concurrent activities:

- **Consideration of Policy Options and Development of Strategy.** We examined the non-market barriers to the achievement of the technical and economic potential and the potential policy instruments available for governments to help overcome these barriers. We considered alternative strategies for development of a portfolio of instruments. We selected instruments taking into consideration these strategies, as well as key public policy objectives (e.g. environmental objectives, economic objectives, fiscal responsibility, fairness, etc.) and the lessons learned from Section 3.
- **Achievable Scenarios.** We constructed a realistic but relatively ambitious achievable scenario for each market segment. Where applicable, this was done on a bottom-up basis looking at individual market segments and regions, which were then extrapolated to the rest of Canada. Scenarios were adjusted to take into account the recommended portfolio of policy instruments. Conversely, where possible and realistic, the portfolios of policy instruments were adjusted to take maximum advantage of what was considered achievable.
- **BAU Scenarios.** In parallel with the development of the achievable scenario, we also developed business as usual scenarios, in order to be able to assess the incremental impact of the proposed initiatives.

Given the nature of the exercise, and the time and resource limitations, the application of the analysis was relatively subjective, relying primarily on the judgment and experience of team members. Notwithstanding the many years of experience and the expertise of our team members, these should be considered illustrative scenarios only.

9.1 Policy Options

Governments have a number of instruments that are, or could be, used to assist NGVs in overcoming non-market barriers, including:

- Financial Incentives (e.g. grants, rebates, tax incentives)
- Regulations (e.g. vehicle or fuel standards)
- Support for Innovation (e.g. financial support for R,D&D and/or early commercialization)
- Information and Suasion (e.g. social marketing)
- Government Procurement (e.g. fleet targets).

In selecting from this menu, there are some important observations drawn from our previous analysis of lessons learned and from the consultations with stakeholders:

- Fuel Tax policy is a visible and powerful instrument in providing a long term price signal to the industry and potential users of natural gas. Thus maintenance of current tax exemptions is an important part of the policy mix.
 - Federal Excise Tax is not assessed on natural gas - cf. Gasoline (10c/L), Diesel (4c/L). All provinces have zero motor fuel tax for natural gas - cf. 14.7c/L on gasoline and 14.3 c/L on diesel in Ontario
- Vehicle incentives (e.g. grants, rebates or tax incentives on vehicles) are needed to overcome the first cost barrier (even though the investments are financially sound, the initial capital requirement acts as a barrier – particularly when combined with the risk inherent in moving to new technology):
 - Incentives have been used successfully in the past. Their impact depends on oil prices and natural gas price differential, and the availability of stations (especially for LDVs).
 - OEMs should be involved in rebuilding LDV opportunity before incentives are offered - may take 2-3 years at best. For a self-sustaining LDV market, OEMs must support upfitting industry with technical information or develop Qualified Vehicle Modifiers (QVMs). The goal should be a much lower cost increment for LDVs than that in the US market now.
 - Competition is a good way to control cost increment. Encouraging new market entrants from Europe is a feasible strategy (Fiat, Volvo, etc), although market would initially be limited to where there are public stations.
- Refuelling infrastructure incentives (e.g. grants to assist the construction of new stations and LNG facilities) are needed in parallel with vehicle incentives to overcome initial risk and small market size. Both are necessary to avoid the “chicken and egg” dilemma.
- Fiscal measures including accelerated depreciation and tax credits applicable to vehicles, stations, and liquefaction facilities could be an alternative to grants and rebates.
- Information/promotion programs:
 - These programs are needed to compliment incentive and research programs. They could range from small programs to provide technical information, to large programs such as the US DOE’s Clean Cities.
 - Government does not have to run information programs – this could be delivered by CNGVA or similar organizations.
 - Information programs should be targeted to specific markets being supported.

9.2 Recommended Strategy

Two potential strategies were considered:

- **Strategy 1: Gradual Development of NGV Markets.** This would be an industry-led approach, with Governments offering modest support, in the form of information, R&D and limited incentives, including maintenance of current tax advantages. Governments would work with provinces, the industry and other stakeholders to further understand the context, the barriers and the opportunities and to identify initiatives for all parties. For example, this could include actions for provinces and municipalities to provide incentives for in the transit market; industry coordination mechanisms to take advantage of HDV opportunities, etc.
- **Strategy 2: Aggressive Development of Selected Markets.** This would be led by both governments and industry in partnerships. Using this study as a starting point, the main market opportunities would be identified and targeted for concerted action by all players. For example, this could involve working with HDV suppliers, fuel suppliers and fleets, offering incentives to start the market for LNG.

Given the barriers identified, and the lessons learned from past program experience, our view is that meaningful development of the market beyond the BAU depends on a more aggressive approach. The achievable scenarios described below are based on this strategy.

9.3 Results - Heavy and Medium Duty Vehicles

9.3.1 *Rationale for the scenario*

Key considerations are:

Medium and Heavy Duty Trucks

- HD and MD in fleet applications constitute a limited sized market. Fleets are typically risk-averse, and are careful with capital outlays.
- Fleet market uptake will be incremental, based on experience from other fleets, demonstrations and secure payback.
- Incremental cost of LNG package is a major obstacle - cost must be reduced before a significant market share can be reached.
- As with energy efficiency, fleets are becoming more sensitive to demands from the clients of trucking services for greener transportation services and lower emissions.
- The best payback can be achieved for long-distance LNG tractor-trailer units, followed by return to base units with benefits from easier refuelling.
- MD trucks in urban and regional delivery and medium size buses (airport shuttles, door-to-door shuttles for the handicapped) are favourable options for the use of CNG.
- Investment by utility companies or other is needed in the manufacturing of LNG plant. The development of such plants can be stepwise, as fleet market will not fully utilize LNG capacity for several years.

Transit Buses

- Growth in transit use of NG is likely to be very slow:
 - Negative attitude from the past NG experience of several transit properties will take time to turn around.
 - Funding support from provinces and municipalities will be needed for bus acquisition - this will take time, especially as Ontario (largest transit market) is working on debt reduction.

Refuse Trucks

- Refuse trucks are suited to NG use because of regular suburban routes and return to base, but current high installation cost makes economics marginal and thus growth is likely to be slow without sustained measures to encourage adoptions. Market could be encouraged by municipal contract policy requiring some level of NG truck use.
(Suggestion by Westport: requiring lower emission truck technologies including natural gas.)
- Use of renewable biomethane is particularly strategic in the refuse truck segment as many public and private sector players have existing landfill assets that could be leveraged.

9.3.2 Possible Government Support and Rationale

Medium and Heavy Duty Trucks

The proposed portfolio would include modest federal government support, primarily in the form of vehicle grants and station incentives to reduce the risk of initial capital outlays for fleets and fuel providers. This would support reductions in GHG emissions from the HDV sector, which has few other options. Examples of specific measures could include:

- Vehicle grant of 1/3 of incremental vehicle cost, declining to 20% by year 5
- CCA incentive on stations, or grants of \$50K-100K for in-yard tank and dispenser depending on size, grants for limited number of LNG multi-fleet stations
- Additional incentives from provinces.

Transit Buses

Transit use of NGV has potential to reduce transit operating costs, reduce urban noise and particulate pollution. Large use of gas per bus and centrally fuelled fleets makes transit one of the best NG opportunities. Examples of specific measures could include:

- Demonstrations of current NG bus technology
- Partial financial support for bus cost increment and fuel station installation

CNGVA suggestion: New bus garages should be built to be fuel flexible, supporting NG and even hydrogen. Bus garages are typically built to last 40-50 years.

Refuse Trucks

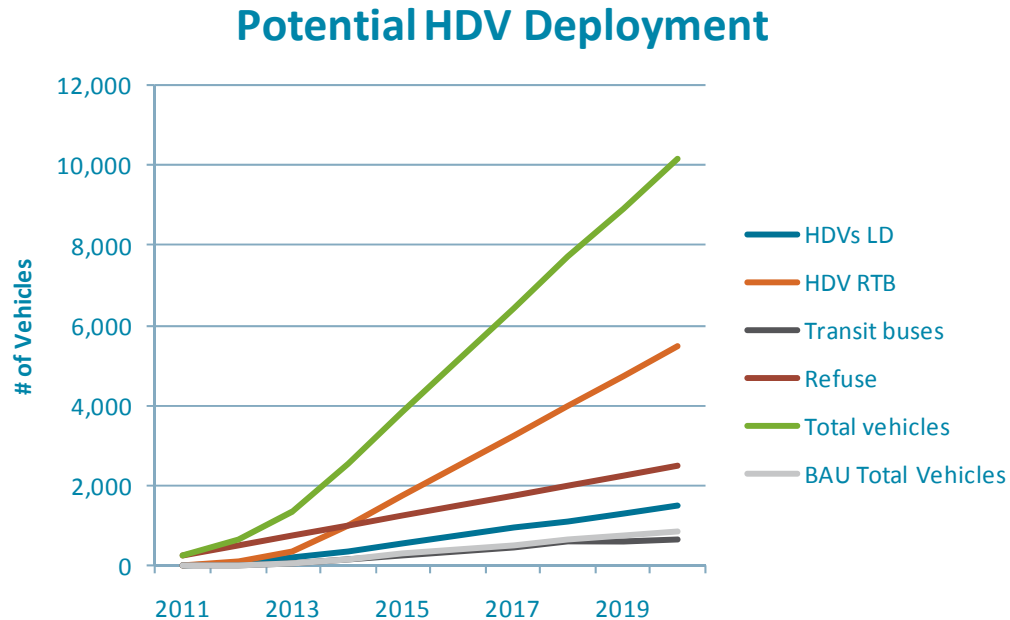
Grants will make the economics more attractive while progress is made to reduce installation costs. Examples of specific measures could include:

- Grants to offset part of cost of vehicle installation and refuelling station

9.3.3 Results

Results are shown in Exhibit 32. These are based on a bottom-up assessment of the potential within the Québec City – Windsor corridor and extrapolation to rest of Canada using a factor of 1.25 for trucks and 1.5 for transit.

Exhibit 32 Achievable potential for the medium and heavy duty NG vehicles



9.4 Results - Light Duty Vehicles

9.4.1 Rationale for the scenario

Rebuilding NGV supply industry in Canada will take some years, so growth will likely be delayed until the second half of the decade and will be slow - a few thousand vehicles per year.

9.4.2 Possible Government Support and Rationale

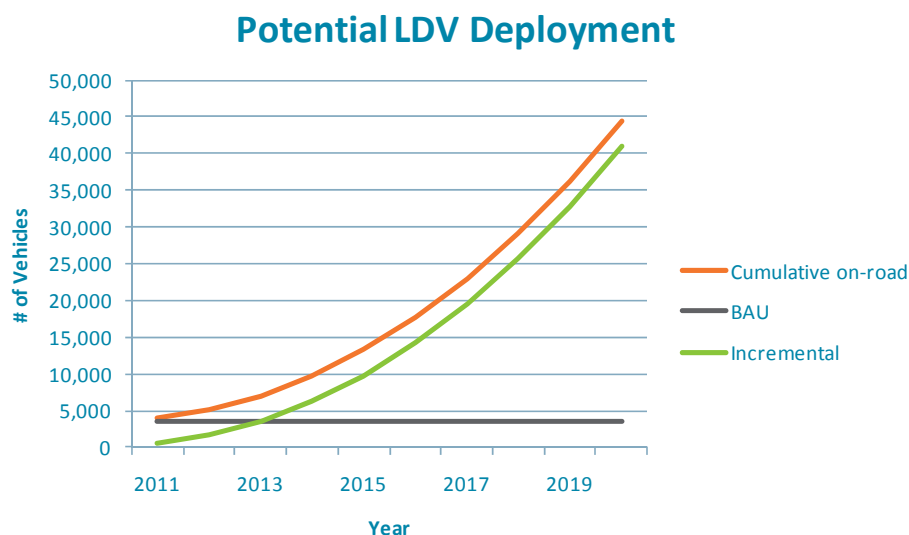
Past experience has shown that government cannot push the LDV market to success, even with strong incentives. Mandates are used in some developing countries, but this would not be justified in Canada. Examples of specific measures could include:

- Work with industry and partners to rebuild this market if there is an interest
- Work with industry and partners to overcome unreasonably high mark-ups on incremental conversion costs.

9.4.3 Results

Results are shown in Exhibit 33. These are based on a bottom-up assessment of the potential in each region of Canada.

Exhibit 33 Achievable potential for the light duty NG vehicles



9.5 Results - Marine

Although the technology is commercially available and is financially viable, the large investments involved in building LNG fuelling facilities for this sector require thorough analysis and relatively long lead times. As the purchase of new vessels occurs infrequently, it would be important to capture such opportunities when they occur. Unfortunately it appears that one of the best opportunities (i.e. purchase of a large fleet of lakers by Algoma) has come too soon to be realized. Although, other opportunities may arise, the uncertainty is too high to include a marine segment in the achievable scenario.

9.6 Results - Rail

Given that the technology for the use of NG in the rail segment is not yet commercial, we do not believe there is a significant achievable potential for this segment within the period to 2020.

9.7 Results – Indoor Equipment

9.7.1 *Rationale for the scenario*

The potential for NG use indoor is established and will need to be developed through steady marketing efforts by the NG utilities and forklift suppliers. The competition in VRA manufacturing must be increased by utilities working with suppliers to offer an economic refuelling package.

9.7.2 *Possible Government Support and Rationale*

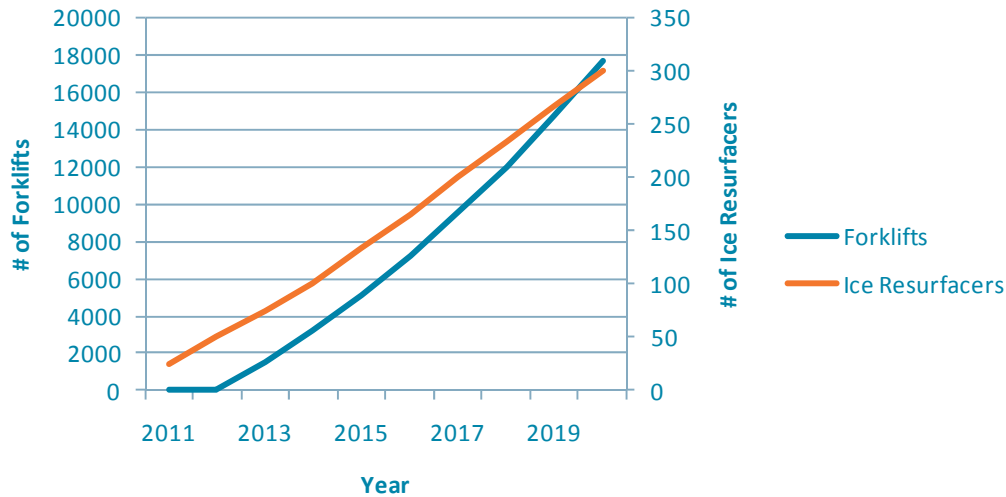
The proposed portfolio is to partially offset the initial cost of refueling and grow this market. grants for refueling stations would be a possibility.

9.7.3 Results

Results are shown in Exhibit 34. These are based on an overall assessment of the national potential for each segment, based on conversations with stakeholders and experts.

Exhibit 34 Achievable potential for indoor NG vehicles

Potential Indoor Equipment Deployment (incremental)



9.8 Fuel Displacement and GHG Emission Reductions

The incremental fuel displacement for all NGV segments included in the achievable analysis is calculated and given in Exhibit 35. The corresponding GHG emissions reduction is given in Exhibit 36.

Exhibit 35 Incremental fuel displacement for all NGV segments based on the achievable potential

Incremental Fuel Displacement from BAU

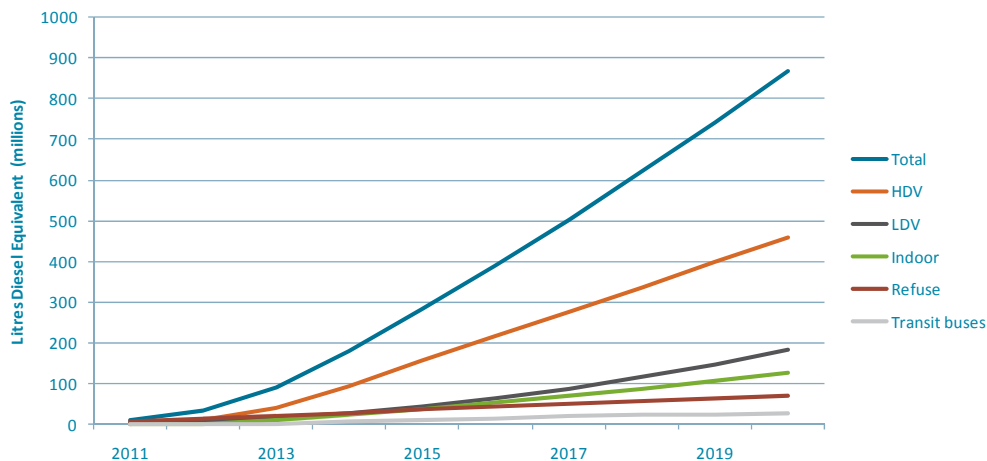
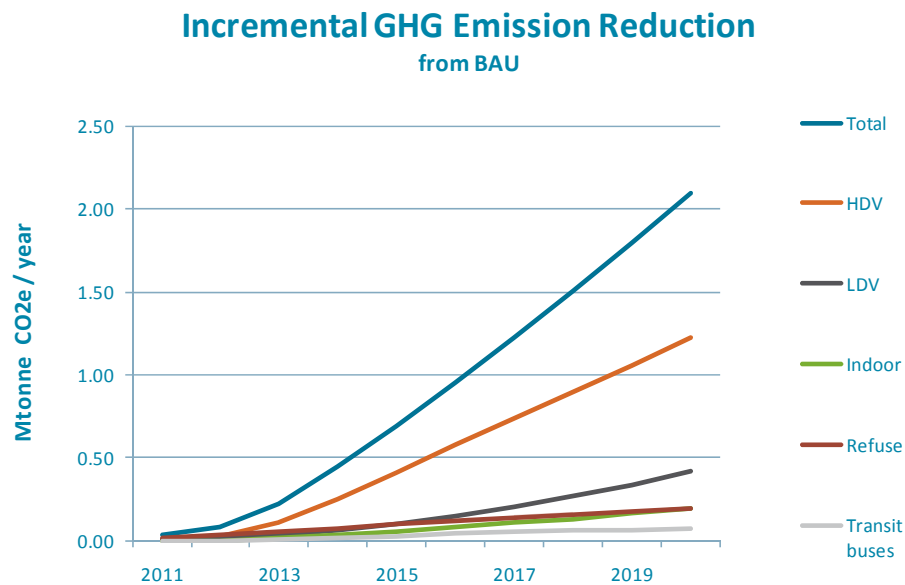


Exhibit 36 Incremental GHG emissions reduction for all NGV segments based on the achievable potential



10 Conclusions

Current Market

The Canadian market for NGVs has stagnated and is lagging far behind other countries. This is due to a variety of factors, including past price volatility and problems with NGV technologies in some sectors. The concurrent lack of availability of vehicles and of fuel continues to act as a “chicken and egg” barrier to further development.

Lessons Learned from Previous Programs

A variety of programs and policies to encourage the development of NGVs have been implemented in Canada and around the world, with varying levels of success. Key lessons include:

- Need for a stable and predictable price advantage for natural gas – mechanisms to manage risk are needed
- Technologies need to be commercially and financially viable on their own – government support should help overcome barriers but should be temporary
- Programs are more likely to be successful if federal, provincial and municipal governments cooperate
- Support is needed both for vehicles and for fuelling infrastructure.

Fuel Supply

The increased access to unconventional gas (in particular to shale gas) appears likely to lead to a surplus in North America by 2020. This surplus is not yet reflected in official forecasts and is subject to some uncertainty, including potential environmental concerns that could constrain the potential.

Current retail fuel supply is characterized by a lack of availability and a lack of competition. As a result, prices are higher than they need to be.

The analysis indicates that investments in fuelling infrastructure could be financially attractive even with somewhat lower prices. However, the business case depends on access to a sufficient market. Thus, potential investors may require assistance to deal with risk and to overcome the initial period of market development.

Technology Trends

The study indicates that NGV technologies are proven and commercially available for all market segments, except rail. In all cases, there remain incremental costs, but opportunities to reduce these costs are being pursued.

Emerging technologies, particularly in the HDV/MDV sector are particularly promising, with new developments signaling that tailpipe emissions are being reduced to a level that could eliminate the need for some of the costly exhaust after treatment components used by conventional fuel vehicles.

Environmental Analysis

The environmental analysis showed that GHG emissions can be reduced by 15-25% depending of the vehicle segment (greater reductions of up to 88% are possible by using biogas). The greatest reductions occur in medium and heavy duty, light duty and refuse truck segments.

It was also noted that NGVs offer other environmental advantages in several segments. In particular the reduction of CACs is important for indoor equipment.

The use of biogas is attractive for municipal fleets that are seeking to drastically reduce GHG emissions while using a locally available fuel source.

Financial Analysis

The financial analysis showed that all NGV segments could potentially be viable without incentives, except the refuse truck segment.

- The forklift segment offers the best return, almost 45%.
- Line haul, transit bus, LDV and marine segments offer attractive returns, in the range of 20%. Because of the large sums involved, the marine scenario is particularly attractive in terms of the absolute dollars.
- The Return-to-Base HDV scenario and the ice resurfacer scenario are only marginally viable, in the range of 10-15% return.
- The refuse truck segment could be financially viable if capital cost increment could be reduced, say by \$15,000.

Several of the segments/scenarios (e.g. refuse, ice resurfacer) have important non-financial advantages that could improve their prospects.

Barriers and Solutions

Despite their technical, financial and environmental benefits, NGVs still face formidable market and non-market barriers. Each of these barriers can be overcome but this will require concerted action by all stakeholders, including governments and industry. In particular a comprehensive communications strategy will be needed to overcome a lack of awareness, understanding and confidence on the part of stakeholders.

Achievable Potential

A number of segments of the market have the potential to see modest NGV penetration, notably the HDV segment.

Achieving this potential will require governments to play an active role, taking the lead in coordinating the actions of other players and providing targeted incentives for both vehicles and fuelling infrastructure.

If realized, this potential increase in NGV penetration would displace up to 850 million litres of conventional fuels per year and reduce GHG emissions by more than 2 megatonnes per year, by 2020.



Appendix A International NGV Programs

USA - Federal Programs

History

NGV strategy in the US has generally focused on high-fuel-use, urban fleets that refuel in a central or constant location (e.g., transit buses, refuse trucks, taxis, and shuttle, delivery, port, and airport vehicles). A variety of programs and initiatives have been implemented over the years.

As in Canada, the various initiatives have had limited success in fostering a sustainable NGV market.

An example of an ineffective federal mandate was the US Federal Energy Policy Act (EPACT 1992), which required certain fleets to purchase a percentage of alternative fuel LDVs. For example, federal LDV fleets had to purchase 75% AFVs. The initiative was meant to stimulate demand and encourage manufacturers to provide more choice. However, a number of Agencies did not meet this requirement and environmental groups have resorted to court action to have the rules enforced.

The Clean Fuels Grant Program was established (year) under the US DoT Federal Transit Administration (not specific to NGVs) program with the purpose of assisting nonattainment and maintenance areas in achieving or maintaining the National Ambient Air Quality Standards for ozone and CO, and supporting emerging clean fuel and advanced propulsion technologies for transit buses and markets for those technologies.

Current Situation

A variety of incentives are available for NG fuel, vehicles, and infrastructure are in place.²⁸ Federal income tax credits are also available to offset the cost of each of these options. In addition, many states and air quality districts offer incentives, and some utilities offer preferential gas rates to customers with a small home refueling appliance sold under the name "Phill".

Clean Cities is a government-industry partnership sponsored by the US DOE Office of Energy Efficiency and Renewable Energy's Vehicle Technology Program, which strives to advance economic, environmental, and energy security through support for practices that contribute to reduction of petroleum consumption.

28 http://www1.eere.energy.gov/cleancities/pdfs/clean_cities_workshop_natural_gas.pdf
<http://www.iangv.org/policy.html>
<http://www1.eere.energy.gov/cleancities/index.html>
<http://www.energy.gov/recovery/cleancities.htm>
<http://www.ngvglobal.com/us-department-of-energy-allocates-300m-for-alternative-fuel-projects-0826>
<http://www.epa.gov/otaq/cff.htm>
http://www.fta.dot.gov/funding/grants/grants_financing_3560.html
http://www.afdc.energy.gov/afdc/progs/fed_summary.php/afdc/US/0
<http://www.aga.org/Legislative/issuesummaries/NaturalGasVehicles.htm>

NGV projects feature in 19 of 25 cost-share projects announced in 2009 under the Clean Cities program that will be funded with ~ \$300 million from American Recovery and Reinvestment Act (ARRA).

In addition, Clean Cities allocates annual funding for grants for vehicles, infrastructure, and education. In 2009, it announced 23 cost-shared grants (10 relating to NG) for the Transportation Sector, which totaled approximately \$13.6 million.

In addition to Clean Cities, the American Recovery and Reinvestment Act of 2009 provided new funding to other programs that may benefit NGVs. These are as follows:

- EPA Diesel Emission Reduction Program - \$300 million to be allocated as follows: (1) \$156 million for the National Clean Diesel Program; (2) \$30 million for the SmartWay Finance Program; (3) \$20 million for “emerging technologies”; (4) \$88 million to states to administer programs; and, (5) \$6 million to EPA to administer programs.
- Federal Transit Administration Capital Expenditures - \$8.4 billion for transit capital improvements.
- Energy Efficiency and Conservation Block Grants (EECBG) - \$3.2 billion for the US DOE for energy efficiency and conservation programs including those involving transportation.
- US General Services Administration Federal Fleet Acquisitions - \$300 million in new funding to help federal agencies acquire motor vehicles with higher fuel efficiency.

USA - States Level Programs

State tax credits for fuel, vehicles, infrastructure, and business development exist in 25 states. In this report, programs in California, New York, Utah, Colorado and Texas are summarized.

California

California has multiple incentives and programs for alternative fuel vehicles.

State Laws and Regulations examples²⁹:

- Alternative Fuel Tax - excise tax imposed on CNG, LNG, paid through an annual flat-fee rate sticker tax, based on weight of the vehicle (e.g., LDV \$36; more than 12,001 lbs \$168). Alternatively, may pay an excise tax on CNG of \$0.07 per 100 cubic feet, \$0.06 per gallon of LNG.
- Public Agency Fleet Emissions Reduction Requirements - South Coast Air Quality Management District (SCAQMD) requires government fleets and private contractors under contract with public entities to purchase cleaner, AFVs. It applies to transit buses, school buses, refuse trucks, etc. and has set purchasing requirements for public and commercial fleets.
- Mobile Source Emissions Reduction Requirements – includes rules for different types of vehicles (e.g., port trucks, transit buses, refuse trucks, fleets for public agencies and utilities) to reduce emissions, including the option to use alternative fuels
- Vehicle Acquisition and Petroleum Reduction Requirements - California Department of General Services is responsible for maintaining specifications and standards for passenger

²⁹ http://www.afdc.energy.gov/afdc/progs/state_summary.php/CA

cars and light-duty trucks purchased or leased for use by state offices, agencies, and departments. Specifications include minimum vehicle emission standards and encourage the purchase or lease of fuel-efficient and AFVs, including a rule that vehicles capable of operating on alternative fuel must operate on that fuel unless the alternative fuel is not available.

- Fleet Vehicle Procurement Requirements - Every city, county, and special district, including school and community college districts, is authorized to require that 75% of the passenger cars and/or light-duty trucks acquired be energy-efficient vehicles, including AFVs that meet California's advanced technology partial zero emission vehicle (AT PZEV) standards.
- Compressed Natural Gas (CNG) Tax Exemption for Transit Use - CNG used by local agencies or public transit operators in the operation of public transit services is exempt from any applicable fuel taxes.
- Alternative Fuel Vehicle Retrofit Regulations – AFV retrofit systems have to be evaluated and certified by the California Air Resources Board (ARB).

Examples of State Incentives follow:

- Alternative Fuel and Vehicle Research and Development Incentives - Administered by the California Energy Commission, it aims to increase the use of alternative and renewable fuels and innovative technologies by providing grants and loans for projects that: develop/improve alternative low-carbon fuels ; expand fuel infrastructure; improve technologies; establish workforce training programs; etc.
- Alternative Fuel Vehicle (AFV) and Fueling Infrastructure Grants – AB 2766 Motor Vehicle Registration Fee Program provides funding for projects that reduce air pollution from on- and off-road vehicles. Eligible projects include purchasing AFVs and developing alternative fueling infrastructure.
- Emissions Reductions Grants - Carl Moyer Memorial Air Quality Standards Attainment Program provides incentive-based funding for the incremental cost of purchasing cleaner than required engines and equipment. Eligible projects include heavy-duty fleet modernization, LDV replacements and retrofits, idle reduction, and the purchase of cleaner off-road vehicles and equipment.
- Lower-Emission School Bus Grants - Provides grant funding for the replacement of older school buses with new buses fueled by diesel or an alternative fuel, provided that the required emissions standards specified in the current Lower-Emissions School Bus Program Guidelines are met.
- Alternative Fuel and Advanced Technology Research and Development - Innovative Clean Air Technologies (ICAT) Program, which is currently on hold, was developed by ARB and co-funds demonstration projects of innovative technologies that will improve emission prevention or control while promoting new industries and jobs in California. Developing alternatives to diesel fuel and diesel engines are of particular interest.
- Technology Advancement Funding - South Coast - South Coast Air Quality Management District's Clean Fuels Program provides funding for R,D,D&D projects that are expected to help accelerate the commercialization of advanced low-emission transportation technologies. Eligible projects have included implementation of clean fuels (e.g. natural gas), including their infrastructures. Approximately \$10 million in funding is available annually with expected cost-share from other project partners and stakeholders.
- Low-Emission Vehicle Incentives and Technical Training - San Joaquin Valley - REMOVE II Program, administered by the San Joaquin Valley Air Pollution Control District (APCD), provides incentives for the purchase of low-emission (e.g., alternative fuel) passenger vehicles, light-duty trucks, small buses, and trucks with Gross Vehicle Weight Ratings of 14,000 pounds or less. It offers between \$1,000 and \$3,000 per vehicle and varies according to the emission certification level and size of the vehicle. Program also includes an AFV

Mechanic Training Component providing incentives for education on the mechanics, operation safety, and maintenance of AFVs, fueling stations, and tools involved in the implementation of the technologies.

There are also Utilities and Private Company incentives in California. For example:

- Alternative Fuel Vehicle (AFV) and Hybrid Electric Vehicle (AFV) Insurance Discount Farmers - Insurance provides a discount of up to 10% on all major insurance coverage for HEV and AFV owners.
- Low-Emission Vehicle Electricity Rate Reduction - PG&E - Pacific Gas & Electric (PG&E) offers a discounted rate for electricity used to charge battery electric vehicles, plug-in hybrid electric vehicles, and natural gas vehicle home fueling appliances.
- Natural Gas Vehicle Home Fueling Infrastructure Incentive - South Coast - Residents of the South Coast Air Quality Management District may be eligible for an incentive of up to \$2,000 toward the purchase of a qualified natural gas vehicle home fueling appliance.
- Low-Emission Taxi Incentives - San Francisco - San Francisco Taxicab Commission committed to reduce GHG emissions from the taxi fleet by 20% by 2012 (compared to 1990 levels). Under the Clean Taxi Program, companies apply for a surcharge of up to \$7.50 on gate fee charged for the use of certain low-emission vehicles. Additionally, grants of up to \$2,000 may be available from San Francisco County Transportation Authority toward the purchase of light-duty hybrid electric and CNG taxis.
- Employee Vehicle Purchase Incentives – Riverside - City of Riverside employees are eligible to receive a rebate toward the purchase of qualified NG vehicle that are purchased from a City of Riverside automobile dealership. The rebate for a new qualified vehicle is worth up to \$2,000, or \$1,000 for a qualified used vehicle.
- South Coast Air Quality Management District's (SCAQMD) Heavy-Duty Natural Gas Drayage Truck Replacement Initiative - The project will replace 180 diesel drayage trucks at the Ports of Los Angeles and Long Beach with LNG trucks. Workshops will be made available to truck operators and technicians. There is also an education/outreach component for alternative fuelled vehicles that will be deployed by the Southern California Association of Governments Clean Cities Coalition and the SCAQMD. (Total DOE award: \$9,408,389)
- South Coast Air Quality Management District's UPS Ontario-Las Vegas LNG Corridor Expansion Project - Project will complete a regional LNG fuelling corridor (700 miles along heavily traveled truck routes) across the southwestern US, making the final connection between the existing public access LNG fuel infrastructure in Southern California and the LNG fuel stations being developed in Utah. UPS will construct a publicly-accessible LNG fuel station and deploy 48 heavy-duty LNG vehicles. The new LNG station will support these 48 trucks, an additional 161 LNG trucks in UPS' fleet, and other LNG fleet operators in the region. (Total DOE award: \$5,591,611)

New York

New York has multiple incentives and programs for alternative fuel vehicles.³⁰

- Alternative Fuel Tax Exemption – CNG is exempt from state sales and use taxes.
- Alternative Fuel Vehicle (AFV) Acquisition Requirements - State agencies and other affected entities must procure increasing percentages of AFVs as part of their annual vehicle acquisition plans. By 2010, 100% of all new LDVs must be AFVs, with the exception of designated specialty, police, or emergency vehicles. State agencies and other affected

³⁰ http://www.afdc.energy.gov/afdc/progs/state_summary.php/NY

entities that operate medium- and heavy-duty vehicles must implement strategies to reduce petroleum consumption and emissions by using alternative fuels and improving vehicle fleet fuel efficiency.

- Low Emission Vehicle (LEV) Standards – Each OEM sales fleet of passenger cars and light-duty trucks produced and delivered for sale in New York must follow the requirements in Title 13 of California Code of Regulations, Section 1962. Under this program, OEMs must make the following commitments: 7% of vehicles must be partial (PZEV), 2% advanced technology PZEV, and 1% ZEV; any ZEV or PZEV models available in California must also be made available in New York. New light-duty passenger car, light-duty truck, or medium-duty passenger vehicles must be certified to the California emission standards. OEMs must also meet a fleet average GHG emissions standard.
- Alternative Fuel Vehicle (AFV) Acquisition Requirements - New York City - At least 80% of the New York City light-duty, non-emergency fleet, and 20% of bus fleets operated in New York City are required to be AFVs.
- Alternative Fuel Use Requirement - New York City - Any bi-fuel motor vehicle owned or operated by the city must use the specified alternative fuel to operate the vehicle.
- Compressed Natural Gas (CNG) Use Requirement – Smithtown - The town of Smithtown requires all contracted residential refuse collection operators to switch from diesel vehicles to vehicles that operate exclusively on CNG.
- Fuel Exclusivity Contract Regulation - Motor fuel franchise dealers are permitted to obtain alternative fuels from a supplier other than a franchise distributor, if the distributor does not supply or offer to supply the dealer with the alternative fuel. Distributors who violate the law by entering into exclusivity contracts will be subject to a fine of \$1000. If the distributor does offer renewable fuels, they are allowed to require the station to use their brands.

Examples of Incentives follow³¹:

- Alternative Fueling Infrastructure Tax Credit - Tax credit available for installation of AFV fueling infrastructure. The tax credit is equal to 50% of the cost of the infrastructure. This includes infrastructure for storing or dispensing an alternative fuel into the fuel tank of a motor vehicle powered by that fuel, including natural gas. The credit expires after December 31, 2010.
- Alternative Fuel Bus and Infrastructure Funding - The Clean Fueled Bus Program, administered by the New York State Energy Research and Development Authority (NYSERDA), provides funds to state and local transit agencies, municipalities, and schools for up to 100% of the incremental cost of purchasing new alternative fuel buses and infrastructure. Eligible buses include those powered by CNG (including dual-fuel technology that is factory built and certified or a new diesel engine with a minimum of 75% use of CNG during typical operation). Eligible infrastructure includes construction and installation of equipment to fuel or recharge alternative fuel buses. Funding for this program is provided by the Clean Water/Clean Air Bond Act.
- AFV and Fueling Infrastructure Funding - The New York State Clean Cities Challenge, administered by NYSERDA, awards funds to members of New York's Clean Cities Coalitions that acquire AFVs or install AFV fueling or recharging infrastructure. Funds can be used to cost-share up to 75% of the proposed project, including the incremental cost of purchasing AFVs, the cost of installing fueling and recharging equipment, and the incremental costs associated with bulk alternative fuel purchases.

³¹ <http://www.ogs.state.ny.us/supportServices/vehicles/defaultCFV.html>
<http://www.nyserdera.org/default.asp>

- AFV Technical Assistance - The New York State Clean Cities Sharing Network, providing technical, policy, and program information about AFVs, is managed by NYSERDA. Membership is open to all organizations, businesses, and individuals interested in AFVs. Other than publishing information about tax incentives, fueling stations, etc., the Network organizes and sponsors technical workshops.
- AFV and Fueling Infrastructure Technical Assistance – NYSERDA’s Flexible Technical (Flex-Tech) Assistance Program provides assistance to fleet managers who want to evaluate the feasibility and cost of adding AFVs and fueling facilities to their operations. Low-cost training for vehicle mechanics is also available through certified institutions.
- Alternative Fuel Product Development Funding - NYSERDA Transportation Research Program sponsors a wide variety of product development efforts aimed at improving efficiency and increasing the use of alternative fuels.
- Alternative Fuel and Advanced Technology Vehicle Funding - New York City - The New York City (NYC) Private Fleet Alternative Fuel/Electric Vehicle Program, administered by the NYSERDA in cooperation with NYC Department of Transportation, helps private companies and non-profit organizations to acquire alternative fuel and advanced technology vehicles. Funds awarded for up to 50% of the incremental cost of purchasing new light-duty NGVs, and up to 80% of the incremental cost for purchasing new or converting medium- and heavy-duty NGVs (dedicated and bi-fuel). In addition, up to 50% of the costs for alternative fueling equipment and installation may be eligible.
- CNG Taxi Funding - New York City - The NYC Clean Fuel Taxi Program provides funding towards the purchase of new CNG taxis cabs or the conversion of gasoline powered taxi cabs to operate on CNG.
- NGV and Infrastructure Rebates and Technical Assistance - National Grid offers a NGV incentive program that provides rebates for NGVs and special rates for CNG fueling. It will also help secure CNG fueling station financing, and provide technical assistance and other services to NGV fleets. Financial awards are made depending on the fleet size, amount of fuel used, and vehicle type.
- Greater Long Island Clean Cities Coalition’s Long Island Regional Energy Collaborative Promoting a Green Economy through Clean Alternatives. The project will deploy five CNG stations and 87 heavy-duty trucks throughout Nassau and Suffolk counties. The alternative fuel stations will be accessible to the public and include the installation of five new CNG fueling stations. The proposed 87 alternative fuel vehicles include: 44 CNG refuse trucks, 40 heavy-duty CNG dump trucks, and three heavy-duty CNG trucks. (Total DOE award: \$14,994,183)
- NYSERDA’s Statewide Alternative Fuel Vehicle Program for CNG, LPG, EV, and HEV Vehicles and Fueling Stations Initiative. The project will utilize multiple alternative fuels and technologies in multiple sectors across the state. Alternative fuel and/or hybrid school buses, municipal vehicles, urban delivery, and utility vehicles will be deployed throughout the state. The fleets include two utility fleets, five cities and towns, three counties, ten private companies, two state fleets, ten school districts, and two universities. The accurate and reliable data collected from the use of these vehicles will provide NYSERDA and DOE insight on how these alternative technologies operate in diverse conditions. (Total DOE award: \$13,299,101)

Utah

Utah has multiple incentives and programs for alternative fuel vehicles³².

³² http://www.afdc.energy.gov/afdc/progs/state_summary.php/UT

- Natural Gas Vehicle Conversion Promotion – The state recommends that EPA revise certification requirements for small volume conversion manufacturers, provide guidance to those manufacturers regarding the conversion of older vehicle models, and continue a NGV R&D funding program. The state also encourages the formation of public and private partnerships to increase the states' vehicle fueling infrastructure.
- Natural Gas Rate Authorization - The Public Service Commission is authorized to find that a gas corporation's request for a NGV rate that is less than full cost of service may be just and reasonable in the interest of the public. If the commission approves such a request, the remaining costs may be spread to other customers of the gas corporation.
- Alternative Fuels Tax - The tax on CNG is \$0.085 per gasoline gallon equivalent; this rate will be modified proportionally with any changes to the traditional motor fuel rate.
- Public Access to State Compressed Natural Gas (CNG) Fueling Stations - The Utah Department of Administrative Services Division of Fleet Services may allow a private individual or entity to purchase CNG from the state's fueling network if there is no commercial fuel site that meets the geographical CNG distribution needs of the individual or entity, and there is no emergency that requires CNG to be reserved for use by state or emergency vehicles. They also provide information on obtaining a GasCard for fueling as well as state fueling network stations that are available to private individuals and entities.
- Provision for Establishment of Alternative Fuel Use Mandate - The Utah Air Quality Board is authorized to mandate fleet vehicles to use clean fuels, if such a mandate is necessary in order to meet national air quality standards.
- Alternative Fuel Vehicle (AFV) and Fueling Infrastructure Grants and Loans – The Utah Clean Fuels and Vehicle Technology Grant and Loan Program, funded through the Clean Fuels and Vehicle Technology Fund, provides grants and loans to assist businesses and government entities in covering: cost of converting a vehicle to operate on clean fuels; incremental cost of purchasing an OEM clean fuel vehicles. The Program also provides loans for the purchase of fueling equipment for public/private sector business and government vehicles. The program can provide grants and loans to serve as matching funds for federal and non-federal grants for vehicles to operate on a clean fuel, purchasing OEM clean fuel vehicles.
- Clean Fuel Vehicle Tax Credit – Income tax credit for 50% of the incremental cost (up to \$3,000 maximum) of a clean fuel vehicle built by an OEM and/or an income tax credit for 50% of the cost (up to \$2,500 maximum) of converting the vehicle to operate on an alternative fuel for vehicles purchased between January 1, 2001 and January 1, 2009. If not previously used, the tax credit may be claimed on used vehicles. Tax credits are available for businesses and individuals. For vehicles purchased after January 1, 2009, the credit amount for OEM CNG vehicles is 35% of the vehicle purchase price or \$2,500, whichever is less; other new clean fuel vehicles may be eligible for a credit of up to \$750. This incentive expires December 31, 2013.
- Incentive for Airport Alternative Fuels Use - The Salt Lake City Department of Airports provides incentives to commercial ground transportation providers who purchase and operate clean fuel vehicles that exclusively operate on approved clean fuels (as designated by Utah code 59-13-102). CNG vehicles are eligible. The incentives are in the form of a credit against ground transportation fees. Incentive credit amounts are \$2,500 for each OEM vehicle or certified vehicle converted to operate on an alternative fuel.
- Natural Gas Technical Assistance - Questar Gas offers technical assistance to customers interested in converting their vehicles to operate on CNG. The company provides financial analysis and fleet consulting services for alternative fuel comparisons.
- Utah Clean Cities (partnered with Questar Gas) was selected for negotiation of an award of up to \$150,000 to install four CNG dispensing units.

- Utah Clean Cities Coalition's Clean Cities Transportation Sector Petroleum Reduction Technologies Program - The initiative includes 16 new CNG public fuelling facilities, upgrades to 24 CNG public fuelling facilities, three new liquid/compressed NG facilities, three new biodiesel public refuelling stations, and increases the number of NGVs operating in Utah by 678. (Total DOE award: \$14,908,648)

In addition to the State programs, one utility offers the following:

- Natural Gas Technical Assistance - Questar Gas offers technical assistance to customers interested in converting their vehicles to operate on CNG. The company provides financial analysis and fleet consulting services for alternative fuel comparisons.
- Additionally, one Utah based project received a grant from the Clean Cities annual funds and one of the Clean Cities ARRA funded projects will take place in Utah:
- Utah Clean Cities (partnered with Questar Gas) was selected for negotiation of an award of up to \$150,000 to install four CNG dispensing units.
- Utah Clean Cities Coalition's Clean Cities Transportation Sector Petroleum Reduction Technologies Program - The initiative includes 16 new CNG public fuelling facilities, upgrades to 24 CNG public fuelling facilities, three new liquid/compressed NG facilities, three new biodiesel public refuelling stations, and increases the number of NGVs operating in Utah by 678. (Total DOE award: \$14,908,648)

Colorado

Colorado has multiple incentives and programs for alternative fuel vehicles³³.

State Laws and Regulations examples follow:

- Alternative Fuel Use and Vehicle Acquisition Requirement – The Executive Director of the Colorado Department of Personnel has adopted a policy beginning on January 1, 2010, motor vehicles that operate on CNG must be purchased, subject to the availability of vehicles and adequate fueling infrastructure. If purchases of CNG vehicles are not possible due to the incremental cost being more than 10%, the Executive Director must purchase another type of flexible fuel or hybrid electric vehicle, again subject to availability and incremental costs.
- AFV Weight Limit Exemption – GVWR limits for AFVs are 1,000 lbs greater than those for comparable conventional vehicles, as long as the AFVs operate using an alternative fuel or both alternative and conventional fuel, when operating on a highway that is not part of the interstate system.
- Alternative Fuels Tax and Vehicle Decal - Fuel tax exemptions are granted for CNG and LPG vehicle owners. Owners of CNG and LPG fueled vehicles are required to purchase an annual tax decal from the Colorado Department of Revenue. All CNG and LPG vehicles must display a current fuel tax decal. Non-profit transit agencies are exempt from the fuel tax.

Examples of State Incentives follow:

- AFV and Hybrid Electric Vehicle (HEV) Tax Credit – An income tax credit is available from the Colorado Department of Revenue for a vehicle that uses or is converted to use an alternative fuel. Beginning January 1, 2010, tax credits are based on specified state-defined vehicle categories, including: Light-duty passenger vehicle, light-duty truck, or medium-duty truck natural gas conversions. The percentage of the actual or incremental cost that may be claimed as a credit for NGVs is 75% until January 2012, and decreases to 25% by January 2016. There is no cap on NGV conversions. For credits claimed in 2010 and 2011, for NGVs

³³ http://www.afdc.energy.gov/afdc/progs/state_summary.php/CO

that permanently displace vehicles or power sources at least 12 years old are eligible for 1.25 times the credit percentages, up to 100%.

- **AFV and Hybrid Electric Vehicle (HEV) Rebate** – The Colorado Department of Revenue offers a rebate for the purchase of an AFV, HEV, or for the conversion of a vehicle to operate using an alternative fuel. Vehicles must be owned by the State of Colorado, a political subdivision of the state, or a tax-exempt organization, and be used in connection with the official activities of the entity. The rebate is a percentage of the incremental cost if used toward purchasing a new vehicle, or is a percentage of the conversion cost. For costs incurred between July 1, 2009, and July 1, 2015, the rebate percentages are based on specified vehicle categories, including: Light-duty passenger vehicle, light-duty truck, or medium-duty truck natural gas conversions. The percentage that may be claimed as a credit for NGVs is 75% until July 2010, and decreases to 25% by July 2015. Each qualified entity is limited to \$350,000 per state fiscal year in total rebates paid.
- **Alternative Fuel Infrastructure Tax Credit** – For tax years beginning prior to January 1, 2011, the Colorado Department of Revenue offers an income tax credit for the cost of construction, reconstruction, or acquisition of an alternative fueling facility that is directly attributable to the storage, compression, charging, or dispensing of alternative fuels to motor vehicles. The credit value was 35% of the cost if claimed during the 2009 tax year, and 20% of the cost if claimed during the 2010 or 2011 tax year. For an alternative fueling facility that will be generally accessible for use by the public, in addition to the person claiming the credit, the percentages specified above will be multiplied by 1.25. The credit has a maximum value of \$400,000 in any consecutive five-year period for each fueling facility.

In addition to the State programs, two utilities offers the following:

- **Natural Gas Fuel Rate Reduction and Infrastructure Maintenance** - Clean Energy Fuels offers services to the NGV industry that include CNG fueling station equipment maintenance, competitive fuel pricing for larger fleet customers, and alternative fuel vehicle financing. Clean Energy also operates public CNG fueling stations in Colorado.
- **Natural Gas Infrastructure Technical Assistance** - Atmos Energy offers preliminary feasibility studies for CNG fueling stations and will assist with vendor selection.

Texas

Texas has multiple incentives and programs for alternative fuel vehicles³⁴.

State Laws and Regulations examples follow:

- **Alternative Fuel Use Required in State Fleets** – State fleets with more than 15 vehicles, excluding emergency and law enforcement vehicles, may not purchase or lease a motor vehicle unless the vehicle uses CNG, LNG, LPG, methanol or methanol-gasoline blends of 85% or greater (M85), ethanol or E85, biodiesel or B20 and higher blends, or electricity including plug-in hybrid electric vehicles. Waivers may be granted for some fleets (e.g., neither the state agency nor a supplier can reasonably be expected to establish adequate fueling for these fuels; unable to obtain equipment or fueling facilities at a cost that is no greater than the net costs of using conventional fuels). By September 30, 2010, state agency

³⁴ http://www.afdc.energy.gov/afdc/progs/state_summary.php/TX
<http://www.glo.state.tx.us/altfuels/NGIPG.html>
<http://www.tceq.state.tx.us/implementation/air/terp/ntrd.html>
<http://www.glo.state.tx.us/energy/in-kind/index.html>

fleets must consist of at least 50% AFVs and use these fuels not less than 80% of the time the vehicle is driven. Covered state agencies may meet these requirements through the purchase of new vehicles or the conversion of existing vehicles.

Examples of State Incentives follow:

- Heavy-Duty Natural Gas Vehicle (NGV) Grants – Texas General Land Office (GLO) has an NGV Initiative Grant Program available for public-sector partners in certain Texas counties. Private fleets also may be eligible particularly those that operate directly under contract for government work or do other government business. The program is funded with a Texas Emissions Reduction Plan grant through the Texas Commission on Environmental Quality. A variety of vehicles, including street sweepers, forklifts, buses, and garbage trucks, are eligible for grants to help cover the cost of replacing diesel vehicles with NGVs.
- Alternative Fuel Grants - The Texas Emissions Reduction Plan (TERP) provides grants for alternative fuel and advanced technology demonstration and infrastructure projects under the New Technology Research and Development (NTRD) Program, which provides incentives to encourage and support research, development, and commercialization of technologies that reduce pollution. NTRD Program is administered by the Texas Environmental Research Consortium, with support from the Houston Advanced Research Center from 2006 to 2009.
- Texas Clean Fleet Program - Beginning in 2010, the Texas Commission on Environmental Quality (TCEQ) will administer the Texas Clean Fleet Program (Program), which encourages owners of fleets containing diesel vehicles to permanently remove the vehicles from the road and replace them with alternative fuel or hybrid electric vehicles. Grants will be available to fleets to offset the incremental costs. An entity that operates a fleet of at least 100 vehicles and places 25 or more qualifying vehicles in service for use entirely in Texas during a given calendar year is eligible to participate in the Program. This Program expires August 31, 2017.
- Natural Gas Fuel Rates and Alternative Fuel Promotion – Through its Natural Gas Program, the Texas General Land Office (GLO) makes competitively-priced NG available to school districts, state and local public entities for use in NGVs. The GLO has also established an alternative fuels program to aggressively promote the use of alternative energy sources, especially for those fuels abundant in Texas. The GLO alternative fuels program serves as a liaison between government and industry.
- Clean Taxi Replacement Grants - Dallas-Fort Worth - The North Central Texas Council of Governments partnered with the US EPA and the City of Dallas to develop the North Texas Green & Go Clean Taxi Partnership as part of Dallas Sustainable Skylines Initiative. This program facilitates the replacement of existing taxis with low emission vehicles. A grant program to offset incremental costs was developed and other non-financial incentives implemented for the purchase of cleaner vehicles.
- Alternative Fuel Vehicle (AFV) Grants - Houston-Galveston - Congestion Mitigation and Air Quality (CMAQ) Program Grants are available through the Houston-Galveston Area Council, via the Greater Houston Clean Cities Coalition, for up to 75% of the incremental cost of purchasing new OEM clean fuel vehicles, clean fuel vehicle conversions/repowers, or establishing publicly accessible alternative fueling infrastructure. This grant is for government and private entities.

Further state level programs exist through the Texas Public Fleet Project

In addition to the State programs, two utilities offer the following:

- Natural Gas Vehicle (NGV) and Fueling Infrastructure Rebates - The Texas Gas Service Conservation Program offers a \$2,000 rebate for the purchase of an NGV or \$3,000 for the conversion of a gasoline powered vehicle to operate on NG. The rebate is available for up to five vehicles per customer; conversions must be performed by a center that is certified by the Railroad Commission of Texas. A \$1,000 rebate is also available for a NG forklift. Additionally, qualified residential and commercial NGV fueling infrastructure may be eligible for a \$2,000 rebate. These incentives are available to commercial and residential customers with specific gas rate codes.
- Natural Gas Infrastructure Technical Assistance - Atmos Energy offers preliminary feasibility studies for CNG fueling stations and may assist with vendor selection.
- Additionally, a couple of Texas based projects received grants from the Clean Cities annual funds and one of the Clean Cities ARRA funded projects will take place in Texas:
- North Central Texas Council of Governments' North Central Texas Alternative Fuel and Advanced Technology - The project will deploy refuelling stations and AFVs in the Dallas-Fort Worth area. The project includes a portfolio of different technologies and fuels, including CNG (three stations and 97 vehicles). In addition to the city fleets, high mileage and high visibility fleets are included, such as Coca-Cola, Sysco, Frito Lay, school districts, and taxis. (Total DOE award: \$13,181,171)

Other International Programs

The NGV programs in the countries listed in Exhibit 1 are summarized.

Pakistan

Pakistan has the largest total number of NGV fleets in circulation for public transportation. In the National Environment Policy of Pakistan issued by Pakistan Ministry of Environment, development and implementation of a plan for conversion of public transport to CNG is included under Energy Efficiency and Renewables section.

Among NGV policies in Pakistan, strong government commitment, liberal licenses for CNG retailing, free market consumer price of CNG, Natural gas tariff for CNG linked to petrol, priority of natural gas connection for CNG, and exemption of import duty and sales tax on import of machinery and kits can be enumerated.³⁵

Toyota Pakistan and Suzuki Pakistan, among others, are quickly producing new models to meet the rising national demand for both public transportation and consumer vehicles.

Argentina

Argentina is second only to Pakistan in the number of NGVs (Argentina 1,745,677; Pakistan 2,000,000 – IANGV 2008) and for number of fuelling stations (Argentina 1,801; Pakistan 2,600). The Government decided in the early 1980s to keep the price of natural gas artificially low (there was a push in favour of natural gas because Argentina had an abundance while diesel supplies were declining).

The Government facilitated the installation of the equipment needed for service stations and created a program for several hundred taxis in Buenos Aires to convert to natural gas.

³⁵ DEVELOPMENT OF CNG AS TRANSPORT FUEL IN PAKISTAN, By S. Naushab Sarwar, General Manager, Karachi Ops. Hydrocarbon Development Institute of Pakistan

The savings realized by the Buenos Aires taxi drivers was enough to convince car owners to convert their vehicles, which in turn prompted more service stations to offer natural gas. With the fuel price differential (between gasoline and CNG), Argentina drivers of CNG vehicles could achieve a quick payback (even within months, depending on distance travelled), and taxation and purchase of CNG engines is also favourable.

A large portion of their public transportation system has also been converted to CNG, encouraged by government-enforced financial incentives.

Local industry is making an effort now, to gradually replace diesel in the HDV fleets. A 3 year plan to convert 1000 HDVs is underway (spurred on by the possible elimination of current diesel subsidies to transportation companies).

Another project being developed in the south cone of South America are the 'Blue Corridors' that will interconnect some cities such as Buenos Aires with Rio de Janeiro and Sao Paulo (Brazil), Montevideo (Uruguay), and Santiago (Chile). These are routes where natural gas is (or would be available) for NGVs and will enhance existing conditions to improve export-import transactions and political integration among the countries³⁶.

Brazil

Brazil ranks third in the world for number of NGVs (1,588,331 – IANGV 2008) and for number of refuelling stations (1,688).

NG was first used in LDVs in 1996, after a law extended the use of NG as a fuel to all types of vehicles (previously allowed only for city buses). Most of the NGVs now are aftermarket converted taxis or commercial MDVs.

In some large cities (e.g., Sao Paulo, Rio de Janeiro), the government is planning to promote programs to displace diesel with natural gas in the city buses.

Strategies are also being developed to make natural gas attractive to fleet operators by resolving issues such as technology, price differentials to diesel engines and fuel, taxation, and operating and maintenance practices. OEMs are increasing their participation in the NGV market, as quality, safety and fuel availability are key issues and this favours OEM products.

The 'Blue Corridors' will also have an impact on the NGV market in Brazil.

The Gas Company Sulgás developed a new short term initiative, GNV: Sinal Verde para a Economia (CNG: Green Sign for the Economy), to expand sales. It was a collaborative effort with a network of fuelling stations, vehicle converters and distributors of NGV equipment and had government support. It was divided into two parts: conversion incentives for new users (bonus of 400 m3 of fuel from Sulgás and a 10% discount on conversion); and fuel discounts for the 37,000 already-converted users.

³⁶ <http://www.guardian.co.uk/world/2008/sep/10/environment.carbonemissions>
<http://www.cngnow.com/EN-US/Vehicles/AroundTheWorld/Pages/default.aspx>
http://www.cleanairnet.org/caiasia/1412/articles-35275_recurso_1.pdf
<http://www.iangv.org/tools-resources/ngvs-by-country/brazil.html>
<http://www.ngvglobal.com/latin-america-ngvs-an-update-report-0820>

Success factors in the growth of the NGV market have included: government incentives; sound regulation, standards and certification; good distribution infrastructure; competitive price of fuel; environmental performance³⁷.

India

Mandates are an effective measure if monitored correctly by authorities. They can apply to vehicle owners (e.g., mandate a percentage of NGVs in a fleet), or they can apply to energy suppliers (e.g., mandate to provide alternative fuel stations).

India provides a well known example of a mandate – the public bus system in Delhi, which is required to use CNG. In July 1998, the Supreme Court of India ordered the CNG program for Delhi, which included the following:

- No buses over 8 years old after 4/1/2000 except on CNG
- All buses on CNG or other clean fuel by 3/31/2001
- Financial incentives for CNG in taxis, three-wheelers etc.
- Increase number of buses to at least 10,000
- Automated I/M (inspection/maintenance) program for commercial vehicles; Strengthen I/M for all vehicles

Government support was provided through further measures, such as:

- Sales tax exemption on conversion kits
- Concessional custom duty on CNG conversion kits
- Allotment of land for CNG stations and pipelines on priority basis
- Banned old vehicles from registering in Delhi

Despite the Supreme Court order, there was resistance. For example, making the order for the CNG bus, but not accepting delivery. Another Supreme Court order of April 5, 2002 fined the Union government for wasting court's time by repeatedly appealing for dilution of the CNG order. The Court imposed fines on diesel bus operators (Rs 500/day (about US\$11), to Rs 1000/day in 30 days). As a result, operators had to take delivery of new buses ordered³⁸.

The Delhi Govt. was directed to phase out 800 diesel buses/month. The National Govt. was to report on measures for extending CNG to other polluted cities.

³⁷ <http://www.iangv.org/tools-resources/ngvs-by-country/brazil.html>

<http://www.ngvglobal.com/brazils-sulgas-offers-incentives-to-boost-natural-gas-conversions-0629>

R.Fernandes, IBP NGV Committee, Brazil NGVs: Beyond a million, NGV-2006, November 7 –9 Cairo, Egypt

³⁸ Anumita Roychowdhury, Centre for Science and Environment, *The Leapfrog Factor - Clearing the air in Asian cities: The Delhi experience*, presented at National Urban Air Quality Workshop, Karachi, September 13-14, 2006
Christopher S. Weaver, Engine, Fuel, and Emissions Engineering Inc., *Challenges and Success of Delhi's CNG Program: Lessons for Other Cities*, presented at The Leapfrog Factor: Towards Clean Air in Asian Cities, New Delhi, March 30 – April 4, 2004 (<http://www.cseindia.org/campaign/apc/pdf/Christopher.PDF>)
<http://www.cleanairnet.org/infopool/1411/propertyvalue-19513.html>

A K Purwaha, NGVAI, *CNG Developments – An Indian Experience*, presented at NGV 2004, Argentina, 26 – 28 October, 2004 (<http://www.iangv.org/tools-resources/reports.html?func=select&id=9>)

A D Chowdhury, Ahok Leyland Ltd., *CNG Programme for Commercial Vehicles in India*, presented at ANGVA 2005, Kuala Lumpur, Malaysia, 26 – 28 July, 2005 (<http://www.iangv.org/tools-resources/reports.html?func=select&id=8&orderby=2&page=1>)

Rajeev Sharma, Indraprastha Gas Ltd., *Compressed Natural Gas Program (CNG) in Delhi – India*, Country Reports Asia-Pacific, presented at NGV 2000, Yokohama, Japan, 17 – 19 October, 2000 (<http://www.iangv.org/tools-resources/reports.html?func=select&id=11>)

The mandate resulted in more than 10,000 CNG buses on Delhi's roads and has been credited with making significant improvements to Delhi's air quality.

Further results included establishing Euro II emission standards in 2000 and Euro III in 2005; implementing more than 100,000 CNG vehicles in one city within a span of 5 years (over 10,000 of which were the bus fleet); and 124 CNG stations were set up in the first 3 years.

Other cross cutting policy measures that resulted from this mandate included improved air quality monitoring, and strengthening the vehicle inspection programmes.

This mandate is unusual, in the sense that it has been imposed by the Supreme Court of India, rather than as a result of Government policy. The decision arose from civil suits that were brought in relation to the right of citizens to breathe clean air.

In 2003, another Supreme Court Order acknowledged the success of the Delhi CNG Project and issued a directive to the Union of India and the state governments to draw plans to introduce clean fuels in 11 polluted cities across India.

Europe

Gasoline in Europe sells for about €1.3/L (about \$1.80/L or \$6.80/gallon), therefore a government mandate to motivate conversion to alternative fuels is unnecessary. Nonetheless, financial incentives from the government to pay for as much as 75% of conversion costs, and environmental concerns provide further incentives among the European community.

While many European countries are developing the CNG vehicle market, Italy, Russia and Germany are currently dominating the agenda. Italy has the largest number of CNG vehicles in Europe and is the 4th largest country in the world for CNG vehicles on the road.

Germany, Poland and France are rapidly working to catch up with Italy. Germany plans to expand their numbers to include 2 million CNG vehicles in circulation by 2020, facilitated by an aggressive program to decrease carbon emissions, and increasing the number of CNG fueling stations from 700 to 1,000 by the end of 2008.³⁹

³⁹ <http://www.cngnow.com/EN-US/Vehicles/AroundTheWorld/Pages/default.aspx>



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NATURAL GAS SUPPLY UPDATE

NATURAL GAS MARKETS BULLETIN

NOVEMBER 2011

OVERVIEW

This bulletin provides an update on recent information regarding North America's abundant supply of natural gas.

KEY OBSERVATIONS

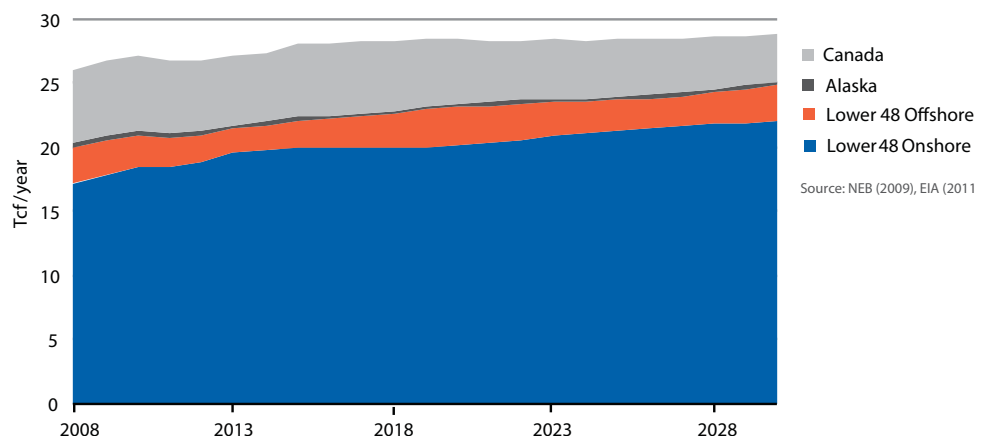
- The emergence of new natural gas sources has transformed the North American natural gas supply picture and contributed to a decline in price from over \$8/GJ in 2008 to under \$4/GJ in late 2011.
- North America has over a century of natural gas supply and innovation promises more opportunities from unconventional, renewable, and other sources.
- As a result, natural gas is smart energy with a very prominent place in Canada's energy future – and our nation's economic future. Abundantly available, clean and affordable, natural gas is a safe and reliable energy choice for buildings and communities, power generation, and transportation.

NORTH AMERICAN NATURAL GAS PROJECTED PRODUCTION

Figure 1 illustrates the projected North American natural gas production to 2030. The fastest growing supply source is shale gas – where further increases are expected, with total production growing by almost fourfold from 2009 to 2035 in the 2011 EIA *Annual Energy Outlook* reference case.

In Canada, the National Energy Board (NEB) forecasts that Canadian conventional production will remain steady in the near term, but taper off by 2020. Growth is anticipated in British Columbia's Horn River and Montney shale/tight gas plays in northeast BC and by 2020 the Northwest Territories' Mackenzie Delta gas is expected by the NEB to reach market.

Figure 1. North American Gas Production Forecast



NATURAL GAS MARKETS BULLETIN:

Natural Gas Supply Update

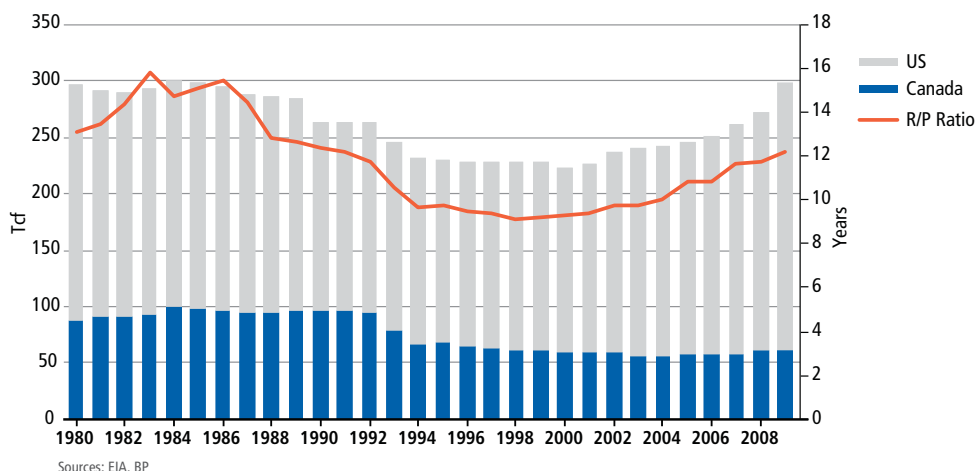
NORTH AMERICAN NATURAL GAS SUPPLY POTENTIAL

Proven Gas Reserves

Proven reserves are quantities of gas immediately available in drilled reservoirs that are connected to pipelines and markets. Reserves are the best indication for estimating future near term natural gas production capabilities. The U.S. and Canada have a combined proven natural gas reserves base of 336 Tcf (275 Tcf in the U.S. and 61 Tcf in Canada). Given that in 2009 North America had 27 Tcf of natural gas demand, this translates into a reserve to production ratio of 12 years. However each year new resource plays are found and new reserves are added into proven reserves, as illustrated in Figure 2.

North American producers continued to add to their proved reserve 'bank' in 2010. In the years 2007 and 2008, U.S. natural gas producers added 34 Tcf to proven reserves with 2008 reserve additions totalling an enormous 27 Tcf, and 2009 additions an even larger 30 Tcf. Canadian producers added 4 Tcf in 2008, one of the largest additions in Canadian history.

Figure 2. North American Reserves and Production



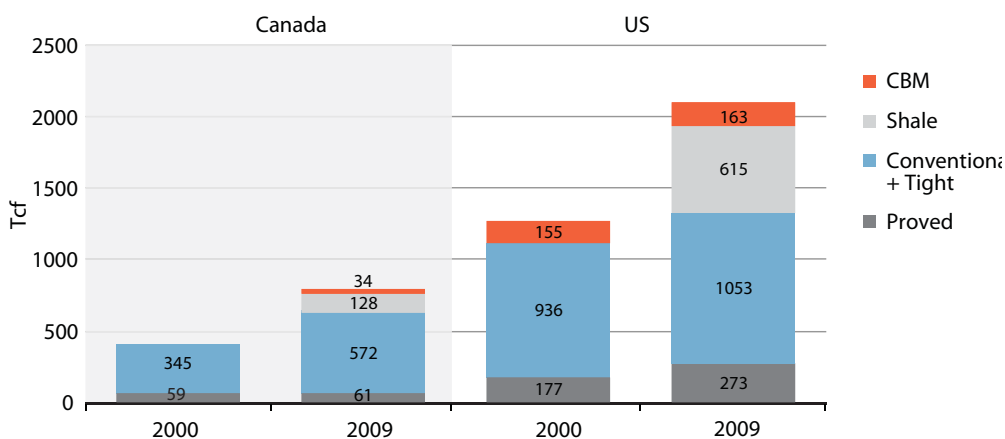
Natural Gas Resources

Natural gas resources are quantities of discovered gas that have been found, but have yet to be connected to pipelines due to a lack of infrastructure (e.g. Mackenzie and Alaska gas resources) and also undiscovered resources (volumes that geologists believe will be found in the future). Figure 3 illustrates the transformation in U.S. and Canadian reserves and resources for 2000 and 2009.

The total volume of North American resources + reserves in 2009 measured 2,899 Tcf, a 73% increase compared to 1,672 Tcf in 2000. The driver of growing gas resources is, primarily, the new shale gas finds across the continent.

In Canada, reserves + resources volume has increased from 404 Tcf to 794 Tcf – a 97% increase since 2000. The United States has undergone a similar transformation with the reserve + resource base increasing from 1,268 Tcf in 2000 to 2,106 Tcf in 2009 – a 66% increase since 2000.

Figure 3. North American Marketable Gas Reserve and Resource Potential - Tcf



Sources: CAPP, CSUR, EIA, Canadian Gas Potential Committee, US Gas Potential Committee, NEB

Shale Gas

Shale rocks containing natural gas can be found in most sedimentary basins.

Shale gas resources are distributed throughout Canada and the U.S. in traditional natural gas development areas such as the U.S. Gulf Coast and Western Canada and also in areas largely unfamiliar to natural gas development such as Quebec, and the U.S. Northeast. The Canadian Society for Unconventional Resources (CSUR) estimates that Canada has 128-343 Tcf of technically recoverable shale gas resources with the most advanced in north-eastern British Columbia (Horn River and Montney). In the U.S., the most advanced plays exist in the U.S. Gulf Coast (Barnett, Fayetteville, Woodford, Haynesville), and the Northeast (Marcellus). The U.S. EIA has estimated 862 Tcf of technically recoverable shale gas resources.

Production from these resources, long considered uneconomic, has increased significantly since 2001 with technological innovation, and combined they currently account for approximately 15% of North America's natural gas supply. Future shale production is expected to be significant as exploration and development continues. However, the amount of shale gas that is ultimately produced will depend on resource characteristics, continued technology improvements, prices, access to resources, and environmental constraints.

Figure 4. North American Shale Gas Deposits



Source: National Energy Board

NATURAL GAS MARKETS BULLETIN:

Natural Gas Supply Update

NATURAL GAS DRILLING AND PRODUCTION TRENDS IN THE U.S. AND CANADA

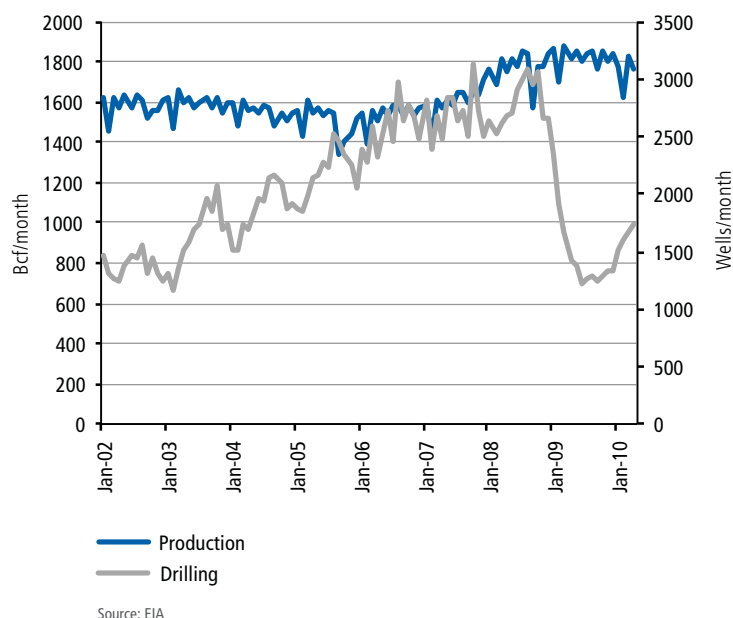
United States

U.S. natural gas production averaged 1,798 Bcf/month in 2010 – a 5% increase over 2009 and a 12% increase over the previous 5-year average (2005-2009). Year-to-date production in 2011 (Jan-Jun) has averaged 1,871 Bcf/month (see Figure 5). The increase in production - largely the result of aggressive shale, CBM and tight gas development seen over the last three years - has halted any debate over North America's ability to meet future natural gas demand.

Although production levels rose in 2010, the number of natural gas wells drilled declined about 45% from 33,009 in 2008 to 18,019 in 2010. Production has continued to increase throughout the 2010 calendar year and to date in 2011.

Further indication of U.S. production strength is demonstrated by lower liquefied natural gas imports. Prior to the growth in shale gas production, the U.S. viewed U.S. LNG imports as the future incremental supply source. Consequently, a number of new import terminals were built bringing U.S. import capacity from 80 Bcf/month in 2005 to 400 Bcf/month in 2010. However, LNG imports have declined from 630 Bcf in 2005 to 430 Bcf in 2010 because of the growth in domestic supply. Projected U.S. imports of liquefied natural gas (LNG) have fallen from 1.2 Bcf/d in 2010 to 1.0 Bcf/d in both 2011 and 2012.

Figure 5. U.S. Production and Drilling



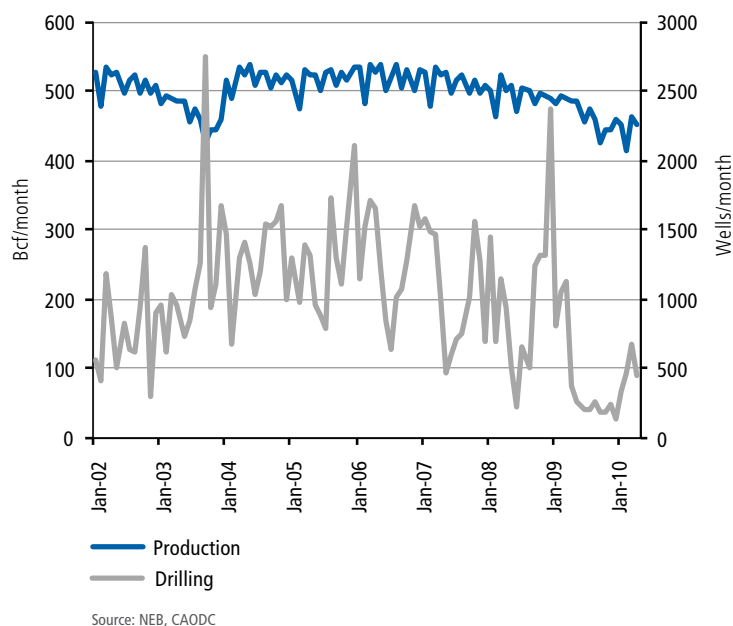
Canada

In Canada, natural gas production has declined 15% from 530 billion cubic feet per month (Bcf/month) in 2002 to 450 Bcf/month in 2010 (see Figure 6). This downward trend in production is driven largely by a 35% decline in drilling from 9,106 wells in 2002 to 5,868 wells in 2010. Drilling declines were brought about by lower natural gas commodity prices (rendering many wells uneconomic), limited conventional drilling targets, and the slow economic growth which reduced the industrial appetite for natural gas.

With respect to shale, CBM and tight gas development in Canada, producers have long been successfully extracting large quantities of tight gas and CBM from Alberta and BC. Shale development is less mature in Canada with the first commercial shale play in northeast BC only occurring in 2007. Since then interest in Canadian shale gas has continued with development of the Montney BC hybrid-shale and tight-gas play seeing growth in production from 0.15 Bcf/d in 2008 to an expected 1.5 Bcf/d in 2012¹. The Horn River Basin shale (also BC) saw about three dozen wells producing gas by year-end 2009 and the NEB expects production to increase to 0.5 Bcf/d by 2012.

In eastern Canada, several wells have been drilled in the Utica Shale in Quebec, preceding a decision by the province of Quebec to cease any new shale developments pending a full environmental assessment audit and report.

Figure 6. Canada Production and Drilling



¹ NEB, short-term deliverability report 2010.

Looking past 2012, shale production is expected to grow in Canada, led by the Montney and Horn River plays. Analysts have compared these favourably to North America's most prolific shale play – the Barnett Shale in Texas. Land sales in BC have reflected this optimism with record prices paid for shale bearing

land parcels both in 2009 and 2010. The NEB estimates that tight and shale gas will make up 60 per cent of national production by 2035 with contributions made predominantly by BC and Canada's north.

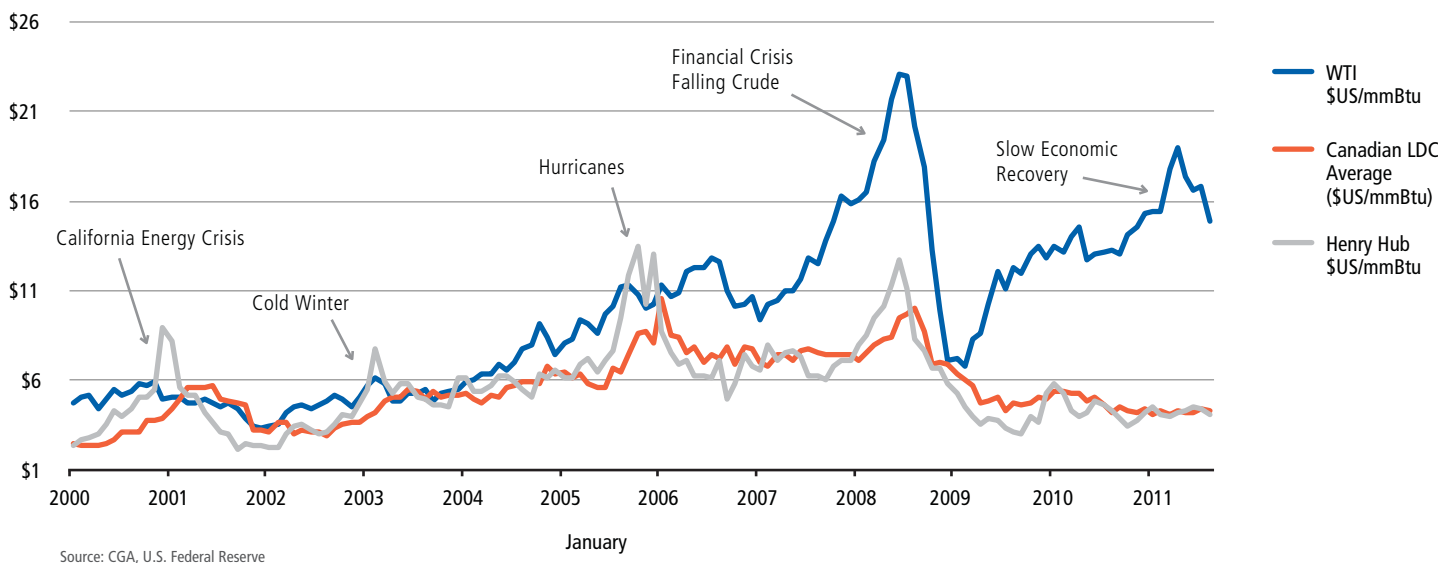
MARKET IMPLICATIONS OF INCREASED GAS SUPPLY

PRICES: The strong supply picture in 2010 pushed the price of natural gas down from \$8.68/mmbtu in 2008 to an average of just \$4.38/mmbtu in 2010. The commodity price of natural gas going forward will be a deciding factor on the level of future natural gas development. It appears that even in the wake of lower prices, producers continued to actively develop their shale gas plays while development of conventional gas was delayed until prices recover or development costs come down.

PIPELINES AND GAS FLOWS: Expanding shale production across Canada and the U.S. has prompted a number of pipeline project initiatives that are beginning to change long-standing natural gas flow patterns and routes.

In Canada, unconventional gas supply from the northeast BC region has spurred a number of pipeline projects that traverse both the traditional eastern route from BC into Alberta, but also the western route to Kitimat BC where the proposed Kitimat LNG export facility is scheduled to commence operation in 2014. The eastern pipelines are the *Groundbirch Pipeline* from the Montney shale and the *Horn River Pipeline Project* from the Horn River shale. The western pipeline is the *Kitimat to Summit Lake Pipeline* that would carry northeast BC gas to the Kitimat terminal where it would then be liquefied and exported to Asian natural gas markets.

Figure 7. Residential Gas Prices vs. Henry Hub and WTI



Natural Gas Supply Update

POLICY LANDSCAPE & GOVERNMENT

Numerous environmental reviews are underway by governments across North America in respect to natural gas production.

As a general rule, those jurisdictions with the least experience in production are being more cautious, as decision makers and the public at large come to understand the production business. By way of examples, the Quebec provincial government and the State of New York have ceased new shale developments pending new reports, whereas in British Columbia, the BC Oil and Gas Commission is reviewing the hydraulic fracking process and seismic activity although there are no plans to stop current production.

In 2010, a review and assessment was undertaken by the Canadian Senate's Standing Committee on Energy, Environment and Natural Resources on a national sustainable energy strategy. Their work, still in progress, includes an outline of key issues to be considered in developing future energy policy in Canada, including the role of various resources like natural gas.

As part of the U.S. Secretary of Energy's Advisory Board, the U.S. Shale Gas Subcommittee has been tasked with identifying measures to reduce the environmental impact and improve the safety of shale gas production. The subcommittee has acknowledged natural gas as a cornerstone of the U.S. economy, but stresses the importance of continuous improvement in the various aspects of shale gas production.

Canada's shale gas and tight gas industry supports a responsible approach to water management, abides by all regulations governing hydraulic fracturing operations, water use and water protection, and is committed to continuous performance improvement. Protecting water resources during sourcing, use and handling is a key priority for the industry. In September 2011, Canadian natural gas producers released guiding principles for hydraulic fracturing that guide water management and improved water and fluids reporting practices for shale gas development in Canada. The principles were created by members of the Canadian Association of Petroleum Producers (CAPP) and apply to all CAPP natural gas producing members, large and small, operating in Canada. The principles can be found at www.capp.ca.

CONCLUSIONS

North American natural gas supply options are more diverse than ever. The result is North America having over 100 years of natural gas supply with innovation continuing to unlock more from unconventional, renewable, and other sources – good news for Canada's energy security, and for Canadian consumers using natural gas.

For more information on natural gas prices and their impacts please contact:

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Canadian Crude Oil, Natural Gas and Petroleum Products: Review of 2009 & Outlook to 2030

May 2011

Petroleum Resources Branch
Energy Sector

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Canadian Crude Oil, Natural Gas and Petroleum Products: Review of 2009 & Outlook to 2030

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Foreword

Canadian Crude Oil, Natural Gas and Petroleum Products: Review of 2009 & Outlook to 2030 is an annual working paper prepared by the Oil and Gas Policy and Regulatory Affairs Division (Oil and Gas Division) of Natural Resources Canada (NRCan). It provides summaries of crude oil, natural gas and petroleum product industry trends in Canada and the United States (US).

The objective of this report is to provide an understanding of the current state of North American oil, natural gas and petroleum product markets in a format that can be quickly and easily read.

Preparing this review and outlook helps the division better inform policy development. It is also a valuable tool for soliciting stakeholder feedback on our division's perceptions of rapidly evolving energy markets.

■ Structure of the Report

The report is divided into four sections:

- 1) *Executive Summary*;
- 2) *Introduction*;
- 3) *Review of 2009* (reviews the calendar year 2008 as well as 2009 and, where data is available, year-to-date 2010, to provide an overview of recent oil, natural gas and petroleum product market dynamics); and,
- 4) *Outlook to 2030* (provides a long-term view of oil and natural gas market fundamentals).

■ Timing of This Report

This is the first time we have analyzed crude oil, natural gas and petroleum products in a single report. This was partly done because the former Oil Division and Natural Gas Division were reorganized in May 2009 to form the new Oil and Gas Division. However, this integrated structure also allows a better understanding of the differences between the three markets, and how the three markets influence one another.

■ Sources

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies

in Canada and the US. Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada.

While every effort is made to provide the most recent data, many sources are continually revising their data. As a result, data for recent years may differ slightly from what was reported in our previous report.

■ Oil and Gas Division Background

Oil and Gas Policy and Regulatory Affairs Division is part of the Petroleum Resources Branch, Energy Sector.

The Oil and Gas Division provides expert technical, regulatory, policy and economic information and advice on crude oil, natural gas and petroleum product markets, pipelines, and regulatory issues to the Minister of NRCan and the federal government.

In addition, the Oil and Gas Division advises the Minister of NRCan on matters related to statutory obligations under the *NEB Act* and *Transportation Safety Board Act*. The Division also includes the Pipeline Arbitration Secretariat.

■ Energy Sector Website

This report is available online at our website: <http://www.nrcan.gc.ca/eneene/index-eng.php>.

Other reports are also available at this website, including the bi-weekly Fuel Focus report, monthly Canadian Natural Gas: Monthly Market Update, and the Review of Issues Affecting the Price of Crude Oil.

■ Feedback

We appreciate your comments, suggestions, and questions. Questions and comments can be directed to Dan Cowan at: (613) 996-5411 or DanielJ.Cowan@NRCan-RNCan.gc.ca.

Executive Summary

The Global Recession

Years of sustained economic growth came to a sudden end in fall 2008 when the US-lead financial crisis triggered the worst economic slowdown since the Great Depression of the 1930s. The effects of the crisis were far reaching and no country was left unscathed. The Canadian economy shrank 2.6% in 2009, the most since 1982.

Energy supply and demand are pillars of modern economies. It follows that the global economic recession had real and tangible impacts on Canada's oil and gas industries, which are the focus of this report. Many of the key developments discussed in this section reflect the picture of a broader, economy wide recession.

The global recession started to affect industrial demand for natural gas and petroleum products towards the end of 2008, however this is masked by the annual data. The recession's full effect was more pronounced in 2009, when industrial demand for natural gas plummeted 8.4% in the US. Canadian industrial demand proved to be much more resilient and only fell by 1%.

Oil and Gas Price Review

The price of Canadian crude oil is set in a global oil market. Similarly, Canadian petroleum product prices reflect international crude oil prices and other factors such as seasonal demand and inventory levels. However, natural gas prices are more continental in nature, and are affected by markets in Canada and the US.

Crude Oil and natural gas prices peaked in July 2008 at \$US 133 per barrel and over \$US 13/MMBtu respectively. Prior to the recession of late 2008, crude oil prices were pushed higher and higher, by growing concerns over supplies, OPEC production cuts, and geopolitical uncertainties in some key producing regions¹. Growing demand, particularly from Non-OPEC Asian countries like China, pushed oil prices higher, as did the devaluation of the US dollar against some key currencies, such as the Euro. Besides those "fundamental" factors, a major increase in large institutional investment (e.g. banks, hedge funds and insurance companies) and speculators is likely to have supported the spike in prices. The soaring oil price pushed refined petroleum products and natural gas prices ever higher as well.

Of note, the price of crude oil is the largest component in the price of refined products, such as gasoline, and product prices usually rise with the increase in the oil price. Natural gas is a product which can sometimes be substituted for petroleum products such as heavy fuel oil, and its price is somewhat influenced by the price of crude oil.

Within a year of their summer/fall 2008 peaks, both crude oil and natural gas lost 80% of their value on the market. Oil bottomed out at \$30 per barrel in late December 2008 and natural gas averaged only \$US 2.84 in September 2009.

Plummeting energy prices were the result of:

- The US financial crisis;
- The fall in equity markets; and
- Lower industrial production and lower energy demand.

Canadian 2008 & 2009 Numbers at a Glance				
	Crude Oil		Natural Gas	
Year	2008	2009	2008	2009
Production	-1%	-1%	-4%	-7%
Domestic Demand	-3%	-5%	+0.7%	-1%
Prices	\$103.5/bbl	\$66.77/bbl	\$7.33/MMBTU	\$3.86/MMBTU
Imports	-2%	-5%	+21%	+25%
Exports	+1%	+1%	-4%	-11%

* Prices: \$CAD – West Edmonton Par for Oil, AECO for natural gas

¹ For additional detail, see our report, *Review of Issues Affecting the Price of Crude Oil*, October 2010.

Producer export revenues and cash flow declined, as did drilling rates and investments in the oil and gas industry.

In 2009, Canadian oil and gas drilling rates declined by half from 2008 levels, and global investment in the petroleum industry declined 19% in this same period.

As economies emerged from the recession, the price of crude oil clawed its way back and settled in the \$US 70-80 range in the last quarter of 2009. Oil prices rose with the expectation that the global economic recovery would support increased oil demand. To the end of 2010, crude oil prices have remained fairly stable, in the \$80-90 range.

Natural Gas

Natural gas prices have recovered to a much lesser extent. Improvements in horizontal drilling technology and multi-stage hydraulic fracturing are helping to unlock enormous natural gas reservoirs across North America. Shale gas has emerged as the new low-cost supply option and it is being characterized as a “game-changer”. Despite declining production in each of the last three years, the Western Canada Sedimentary Basin (WCSB) is no longer thought to be in permanent decline. Vast shale resources, particularly in Northeastern British Columbia, offer the possibility of increased domestic production over the long term.

Shale gas development is well established in the US and is growing quickly in Canada. Shale gas is providing a renewed optimism that North America now has an enormous and secure source of natural gas for decades to come. The burgeoning shale gas development comes on the heels of tremendous investments in Liquefied Natural Gas (LNG) import terminals.

Abundant shale gas, and abundant LNG import and regassification capacity, may act as a ceiling for natural gas prices and contribute to a lasting decoupling of oil and gas prices. Relatively low natural gas prices are fuelling efforts to expand natural gas’s market share, including in new applications such as transportation.

Natural Gas Paradigm Shift

For years industry spoke of the natural gas drilling and production treadmill, whereby more and more drilling was required to sustain production. During 2001-2006, North American natural gas production stagnated and prices spiked up and down as demand changed, leading us to describe this as a “supply limited market”. Unconventional production is changing the story. Nowhere is this more clear than in the US in 2009, when natural gas drilling collapsed (down 44%) and yet overall production grew by 3%. The strength in natural gas production is due to the shift towards horizontal wells targeting shale gas, which are typically much more productive than traditional vertical gas wells targeting conventional production. Similar trends could emerge in Canada as unconventional gas development grows in the future. Clearly the North American natural gas market is no longer supply limited, but is in a period of relative abundance.

Crude Oil

The shift towards unconventional production also holds on the oil side. New technology, successfully employed in shale gas developments (including horizontal drilling and multi-stage fracture stimulation) has successfully been employed in the Bakken oil formation in Saskatchewan, and more recently in the Pembina oil field in Alberta. In addition, it's now clear that Canada's mature oil fields could be revitalized, using unconventional production techniques.

Oil Sands

By early 2009, with the recession driving crude oil prices down, \$100 billion in oil sands projects were on hold. However, oil prices subsequently recovered following the recession, and oilsands investments and developments are now once again back on track for rapid growth. Within the last year, rising petroleum prices have prompted the re-start of a variety of oil sands mining and in-situ projects

including: Suncor Energy's Firebag expansion, Imperial Oil's Kearl project, Cenovus's Narrows Lake project, Devon Energy's Jackfish expansion, and ConocoPhillips and Total's Surmont project.

By 2030, oilsands production is expected to account for up to 90% of Canadian production. The shift towards unconventional production has long been anticipated as 97% of Canada's proved oil reserves are in the form of oil sands. New processes and improvements in efficiencies are also helping to curb the expected demand for natural gas per barrel of oilsands produced.

Refined Petroleum Products

Overall, demand for refined products in Canada slowed down in 2008 along with the worldwide economic slowdown, and continued to decline in 2009. In fact, demand in 2009 was 6% lower than in 2008 at 96.5 billion litres, the lowest since 2002.

In 2009 Canadians consumed 42.3 billion litres of gasoline, an increase of 0.6 billion litres over 2008, a year when gasoline consumption had dropped by 0.5 billion litres.

Domestic sales of diesel fuel in 2009 were 26.0 billion litres, 8% lower than the year before. In 2007 and 2008 diesel demand had increased, a reflection of the strong growth in the Canadian economy and a growing proportion of diesel-powered vehicles in the fleet.

Demand for heating oil, or light fuel oil, totalled 3.4 billion litres in 2009, 0.4 billion litres or 10% below 2008. This mainly reflects the loss of share to natural gas and electricity in the space heating markets of Ontario and Quebec.

Canadian refinery capacity has increased slightly over the last decade – despite the closure of the Petro-Canada refinery in Ontario 2005. The refinery utilization rates have been dropping steadily since 2004, declining more significantly in 2009 because of lower demand for oil products, poor refining economics stemming from the economic downturn, and unscheduled refinery shut-downs.

Canadian gasoline prices in 2009 and 2010 were less volatile than in 2008, averaging 95 cents a litre in 2009 and \$1.04 in 2010, down from the \$1.14 registered in 2008. Diesel fuel prices averaged 90 cents per litre in 2009 and \$1.01 in 2010, compared to \$1.25 per litre in 2008.

Resource Size and Adequacy

Unconventional resources are also helping to stem concerns about Canada's long term ability to satisfy its energy needs. Canada's proved oil reserves are now the third largest in the world at 174.2 billion barrels (Bbl). On account of Alberta's oil sands, Canada now has at least 175 years of remaining crude oil reserves, at current production rates.

New estimates for natural gas resources are being developed to account for shale gas. North America is now thought to have over 100 years of natural gas supply at current production rates, largely on account of shale gas. It's clear that Canada has abundant oil and natural gas for long-term energy needs.

Outlook to 2030

Crude Oil

The crude oil price outlook to 2030 (from expert consultants and energy forecasters) shows a tendency towards rising prices. However, there is no consensus, which is not surprising given the variety of factors which can influence the price of oil.

A survey of Canadian crude oil production forecasts shows considerable variability particularly in the long-run. However, all of the forecasts show a clear shift towards the oil sands and a decline in Canada's conventional oil production. All of the forecasters expect that the decline in conventional oil production will be more than offset by rising oil sands production.

Overall, Canada's oil sands production could more than triple by 2030. Canada has a large and growing net surplus of crude oil. The domestic market for oil sands production could grow with rising

production. Surplus Canadian crude oil production will help meet the demands for oil in the US market, and could possibly be exported to a new market in Asia.

Natural Gas

A survey of expert consultants and energy forecasters show that North American natural gas demand is widely anticipated to increase by about 1% per year through to 2030. Canadian natural gas production is expected to continue a slow decline or remain stagnant until 2013 or 2014, after which production begins to rise slowly, due to unconventional gas development. Combined with Canadian natural gas demand growth, this implies a continued drop in Canadian natural gas exports to the US. The expected impact will be continuing declining natural gas exports to the US.

Natural gas prices are inherently hard to predict, even more so at a time when enormous supplies are on the verge of hitting the market. However, according to the forecasters surveyed, natural gas prices will gradually increase over the Outlook period to 2030. Natural gas is expected to continue trading at a considerable discount to crude oil on an energy content basis throughout the forecast period. Forecasters expect crude oil and natural gas prices to remain decoupled on an energy-content basis and for the price differential to widen somewhat.

Introduction

Importance of the Oil and Gas Industry to the Canadian Economy

Oil and natural gas are vital sources of energy for the world and will likely remain so for many years to come. The International Energy Agency (IEA) projects that oil and natural gas will provide 50% of the world's energy mix in 2035.

Oil is a key product for the world's agriculture industry. "The energy in one barrel of oil," notes the New Scientist (June 28/08), "is equivalent to that of five labourers working non-stop for a year." Oil is truly a key fuel which has helped the world's civilization advance in the 20th and 21st century.

In North America, two-thirds of oil is used in the transportation sector. Canada is geographically vast and oil gives us gasoline, diesel, and jet fuel to get around. From oil we get thousands of key products, from petrochemicals to building materials to plastics. Oil and natural gas are both used for power generation and as a heat source.

Like oil, natural gas is a crucially important energy source for consumers and business. Natural gas is used in the production of fertilizers and so plays a key role in food production. In Canada, natural gas is also used to extract oil from the oil sands.

The oil and natural gas industries are major drivers of Canada's economy:

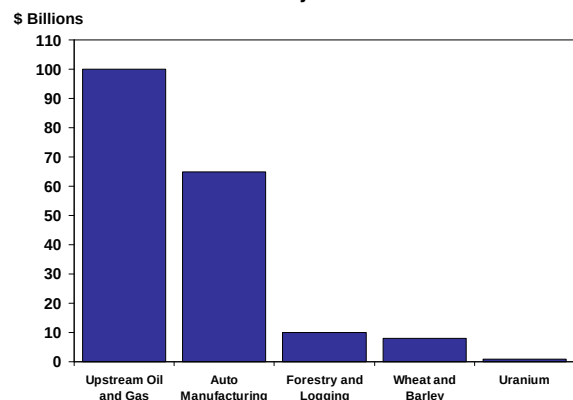
- An ARC Financial report estimates that upstream oil and gas accounts for \$100 billion of revenue annually in Canada, considerably more than the next largest product group (autos) at \$65 billion.
- Over the next 25 years, Canadian Energy Research Institute (CERI) expects the Canadian oil and gas industry to sustain almost 25 million person years of employment, or almost one million jobs each year², and have a \$3.6 trillion (\$2008) impact on the Canadian Economy.

² There are not 1 million people working directly in oil and gas in Canada. The figure includes indirect jobs such as services driven by oil and gas jobs.

- Petroleum companies make up 20 to 30% of the value of the Toronto Stock Exchange and directly account for about 5% of Canada's GDP.
- \$54 billion in Canadian oil and natural gas capital investment in 2008³.
- In 2009, Canada's petroleum exports (crude oil, petroleum products, and natural gas) accounted for 21% of all Canada's exports. Oil and natural gas exports are a key component of Canada's merchandise trade surplus with the outside world. This surplus benefits all Canadians⁴.
- Millions of Canadians are affected by the petroleum industry through employment, or ownership in shares of companies, Registered Retirement Savings Plans and mutual funds.
- The high value of the Canadian dollar is largely due to the value of oil and gas produced in Canada.

The oil and gas industry is a key source of revenue for federal and provincial governments. In 2008, the Canadian oil and gas industry paid \$26 billion in taxes and royalties to governments⁵. Over the next 25 years, the federal government could receive \$409 billion in tax revenue from the oil and gas industry, while provinces could take in an additional \$282 billion⁶.

Annual Revenue for Major Canadian Industries



Source: ARC Financial

³ CAPP Website

⁴ Statistics Canada (2008) CANSIM Table 228-0003

⁵ CAPP Website

⁶ CERI report on the Economic Impact of the Petroleum Industry in Canada, July 2009.

Review of 2009 – Crude Oil Market

Market Structure

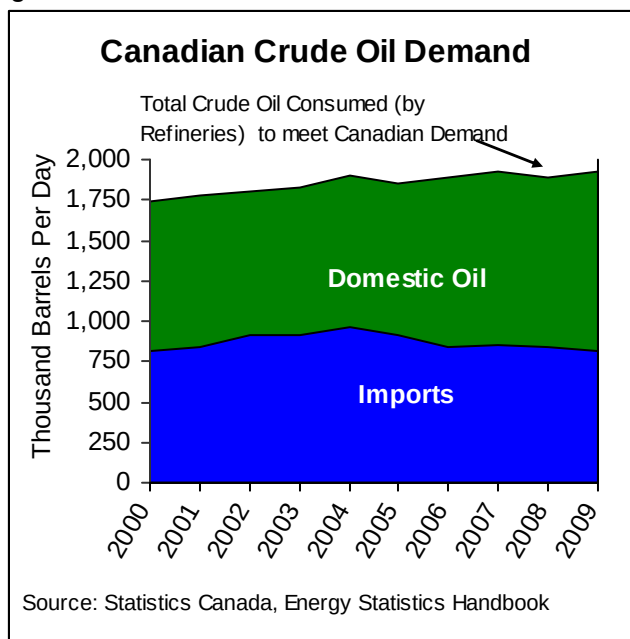
Canada is the 6th largest oil producer in the world, and a price taker in a global oil market. Canadian crude oil is sold both domestically and in the US market at the world price. Despite the fact that Canada is a major net exporter of crude oil, refineries in Atlantic Canada and central Canada continue to import crude from producers overseas. This occurs because of the low cost of moving crude oil by ship, and the relatively high cost of pipelining crude oil across Canada. Some of the crude imported is re-exported to the US in the form of refined petroleum products.

Crude Oil Demand

Refineries transform crude oil into refined products which are consumed by industry and the public. The figure below shows the total amount of crude oil consumed by refineries (both imports and domestic crude oil) to meet the demand for refined products in Canada.

As seen in the figure below, between 2000 and 2009, Canadian demand for crude oil ranged from 1.7 to 1.85 million barrels per day (mb/d). Canadian demand for crude oil peaked in 2007, at 1.85 mb/d.

In 2008 and 2009, Canadian demand for crude oil slowed down, reflecting the impact of the global economic slowdown. However, there are

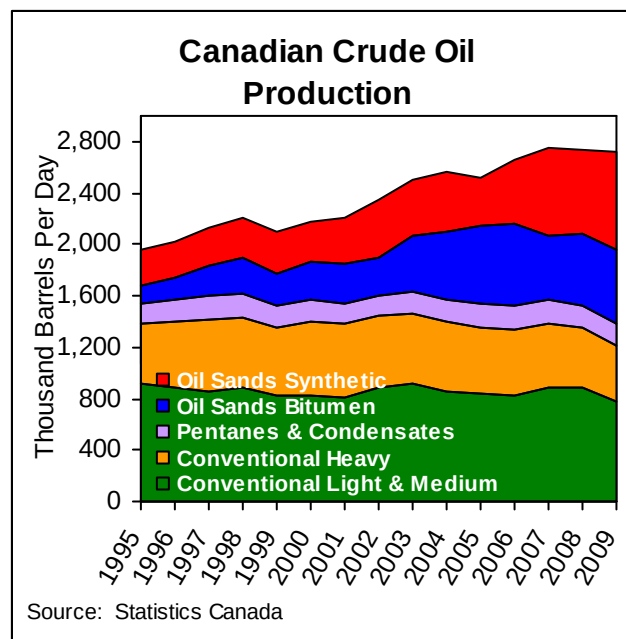


now some signs that the global economic recovery has begun. Like other countries, Canadian crude oil demand could recover somewhat with the global economic recovery.

Canada consumes far less crude oil than it produces, and this situation is likely to continue into the foreseeable future. In 2009, Canada recorded a huge net surplus of more than 840 thousand barrels per day (kb/d). Nearly all crude oil exported from Canada was to the US market.

Crude Oil Production

The figure below shows total Canadian crude oil production for the 1995 to 2009 period. Canadian oil production is growing quickly. Between 1995 and 2009 Canadian crude oil production grew from 1.97 mb/d to 2.72 mb/d. All of the increase in Canada's oil production came from the oil sands, where production rose from 430 kb/d in 1995 to 1.34 mb/d in 2009. For 2009, despite a significant drop in the price of crude, and a large drop in conventional oil drilling, Canadian crude oil production of 2.72 mb/d was very close to its output rate of 2008 (2.74 mb/d). In fact Canada's crude oil production fell by less than one percent. The growth in oil sands output offset almost all of the loss in conventional crude oil production.



Canadian Crude Production by Province and Territory (kb/d)														
Domestic Production	B.C.		Alberta		Sask.		Manitoba		East Coast		Rest of Canada		Canada	
	08	09	08	09	08	09	08	09	08	09	08	09	08	09
Heavy			156	145	309	289							465	434
Light/Medium	23	22	347	316	130	134	23	26	342	268	18	17	883	782
Condensates	4	4	15	14					11	8			31	27
Pentanes	6	7	141	132	1	1					2	2	149	142
Bitumen			549	575									549	575
Synthetic			653	764									653	764
Total Production	33	33	1,861	1,946	440	424	23	26	353	276	20	19	2,731	2,724
Percentage	1	1	68	71	16	16	1	1	13	10	1	1	100%	100%

Source: Statistics Canada, Energy Statistics Handbook. Figures are rounded.

The table above shows Canadian crude oil production by province and territory. Canadian crude oil production is spread out across Canada; however, most Canadian production is centred in the Western Canadian Sedimentary Basin. In 2009, Alberta dominated Canadian crude oil output with 71% of the nation's total. The Western Canadian provinces of Alberta, British Columbia, Saskatchewan and Manitoba accounted for 89% of production. Newfoundland and Labrador offshore production made up almost 10% of total Canadian output. Finally, Ontario, Nova Scotia and the Northwest Territories production make up the remaining 1% of production.

Within Canada, there is a fairly high degree of concentration of oil production within a small number of producers. In 2009, the top 10 Canadian oil producers controlled 65% of total Canadian oil production. The August 2009 merger between Suncor Energy and Petro-Canada created Canada's largest energy company, with crude oil production at 393 thousand barrels per day (kb/d) in 2009.

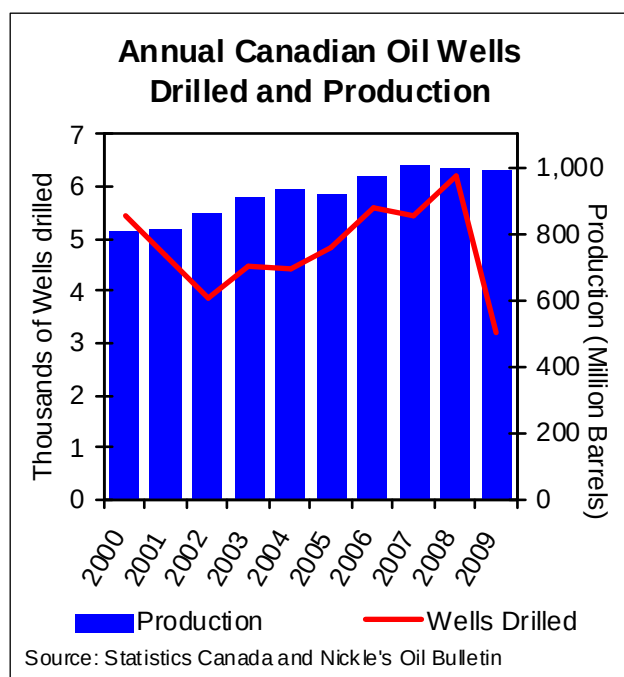
2009 Top 10 Canadian Oil Producers			
Rank	Company	kb/d	Percent
1	Suncor Energy*	393.5	14.4%
2	Canadian Natural*	284.8	10.5%
3	Imperial Oil*	244.0	9.0%
4	Husky Energy*	205.1	7.5%
5	Shell Canada	119.0	4.4%
6	Encana ¹	115.8	4.3%
7	Conoco Phillips	113.0	4.1%
8	Penn West*	104.0	3.8%
9	Canadian Oil Sands Trust*	103.1	3.8%
10	Devon Canada	94.6	3.5%
Total Canada production		2,724	100%

Source: Oilweek Magazine, July 2010. * denotes gross production
¹ Encana split into two energy companies on December 1, 2010.

Oil Wells Drilled

The total number of oil wells drilled in Canada in 2009 was lower than in previous years. In 2009, 3,197 oil wells were completed compared to 6,223 in 2008, which translates into a 49% drop. Note that wells drilled is an imperfect measure of unconventional oil development, as oil sands production is extracted through in situ processes (which requires drilling), but also by mining (which does not involve drilling). The graph below illustrates that in 2009, oil wells drilled were the lowest of the decade. Lower commodity prices throughout the first half of 2009 were a major factor contributing to the lower oil well count.

In 2009, despite the huge drop in conventional drilling, Canadian crude oil production remained virtually unchanged from its 2008 level because increased oil sands production made up for a loss of conventional production.



Canada's Oil Resources and Reserves

Oil sands are a naturally occurring mixture of sand or clay, water and bitumen⁷. Canada's oil sands are found in three main areas: Athabasca, Peace River and Cold Lake. Canada's oil sands are extracted using both mining and in situ drilling techniques. Around 20% of Canada's oil sands reserves are close enough to the surface (up to 75 metres) to be mined. The remaining oil sands reserves are too deep to be mined (more than 75 metres) and in-situ drilling techniques are required to extract the oil. In situ techniques use drilling technology to inject steam into a deposit to heat the oil sand thus lowering the viscosity of the bitumen. The hot bitumen migrates towards the wells, bringing the oil to the surface, while the sand is left in place.

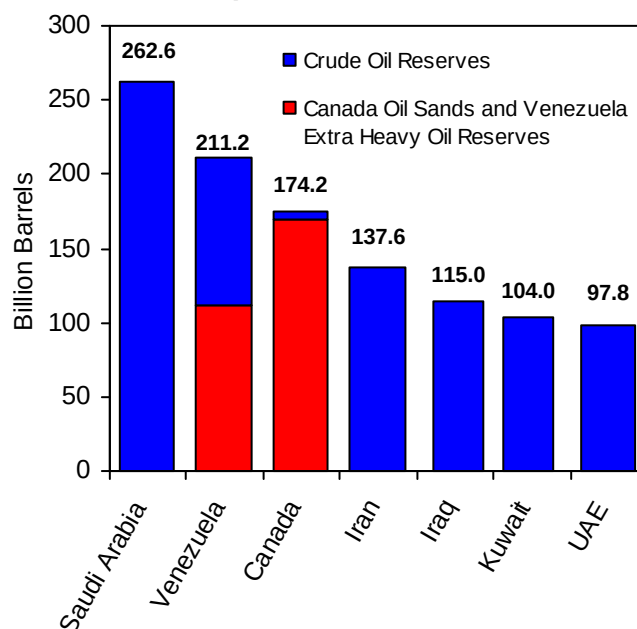
Canada's oil sands are still in their early stages of development. Since 1967, only seven billion barrels (bbl) of crude oil has been extracted from the oil sands. In 2009, 544 million barrels of bitumen were extracted from the oil sands (approximately 1.5 mb/d). In 2009, all crude bitumen produced from mining, as well as a small portion (about 12%) of in situ production was upgraded in Alberta, yielding 279 million barrels of synthetic oil.

In Canada, the amount of discovered in-place (not all in-place amounts are economically recoverable) bitumen resources (oil sands) is estimated at 1.8 trillion barrels. This resource is so vast it exceeds the total volume of world oil production to date. For comparison, the 150 year cumulative total of world oil production-to-date is approximately 1 trillion barrels.

Proved oil reserves are economically recoverable with a high degree of certainty using current technology. Ten percent of Canada's discovered bitumen resources are now considered to be proved. Canada's proved oil sands reserves are estimated at 169.9 bbl.

As shown in the figure above, Canada's proved oil reserves are the third largest in the world at 174.2 bbl. Only Saudi Arabia, with 262.6 bbl of oil, and Venezuela with 211.2 bbl have a larger volume of proved oil reserves. The seven countries shown collectively represent about 75% of the world's proved oil reserves. Six of

World's Top Proved Oil Reserves



Source: Oil and Gas Journal, December 6, 2010; CAPP

the countries are Organization of Petroleum Exporting Countries (OPEC) members (Canada is not). Today, OPEC controls 72% of the world's oil reserves, and produces about 40% of the world's oil production.

Canada accounts for about 12% of the world's proved oil reserves, and 97% of Canadian reserves are in the form of oil sands. Based on the current rate of production, Canada has at least 175 years of crude oil reserves.

In the future, with technological improvements, the volume of Canada's proved oil sands reserves could grow substantially. The province of Alberta estimates that proved oil sands reserves, currently estimated at 169.9 bbl, could grow to 315 bbl as technology improves. This does not include oil sands that could one day be extracted from Saskatchewan.

Unlike the oil sands, Canada's conventional oil reserves are spread across Canada's provinces and territories. Canada's conventional proved oil reserves are currently estimated at 4.3 bbl. The table on the next page shows the location of Canada's proved conventional oil reserves by province and territory. Alberta holds around 35% of Canada's conventional oil reserves and the Western Canadian provinces of Alberta, British Columbia, Saskatchewan and Manitoba collectively account for about 61% of Canada's conventional oil reserves.

⁷ The extremely viscous oil contained in oilsands deposits is commonly referred to as bitumen. It is a very heavy oil.

Canadian Conventional Crude Oil Reserves		
Location	Million barrels	Percent
British Columbia	113	2.6%
Alberta	1,495	34.6%
Saskatchewan	959	22.2%
Manitoba	53	1.2%
Ontario	10	0.2%
Mainland Territories	12	0.3%
Mackenzie Beaufort	339	7.8%
East Coast Offshore	1,344	31.1%
Total	4,325	100.0%

Source: Canadian Association of Petroleum Producers

The East Coast offshore areas represent about 31% of conventional oil reserves. Canada's remaining proved conventional oil reserves are located in Ontario, the Mackenzie/Beaufort Area and the Mainland Territories.

Crude Oil Inventories

Crude oil is mainly stored at refineries and near major pipelines. The graph at the top right shows the monthly Canadian crude oil inventory levels at the Canadian refineries over the January 2007 to December 2009 period.

Monthly Canadian crude oil inventories levels ranged from just under 18,518 thousand barrels to almost 23,827 thousand barrels. Seasonal variations in crude oil inventory levels are also visible. The winter months show spikes in inventories for refineries to produce heating oil. In the January 2007 to December 2009 period, crude oil inventories at refineries varied between 11 and 14 days of forward supplies.

Canadian refineries constantly replenish their supplies of crude oil through pipelines and crude oil tankers to ensure that adequate supplies are maintained for Canadians. Refineries in Atlantic Canada have the highest crude oil inventories in terms of forward supply levels as they rely on imported crude almost exclusively.

Crude Oil Prices

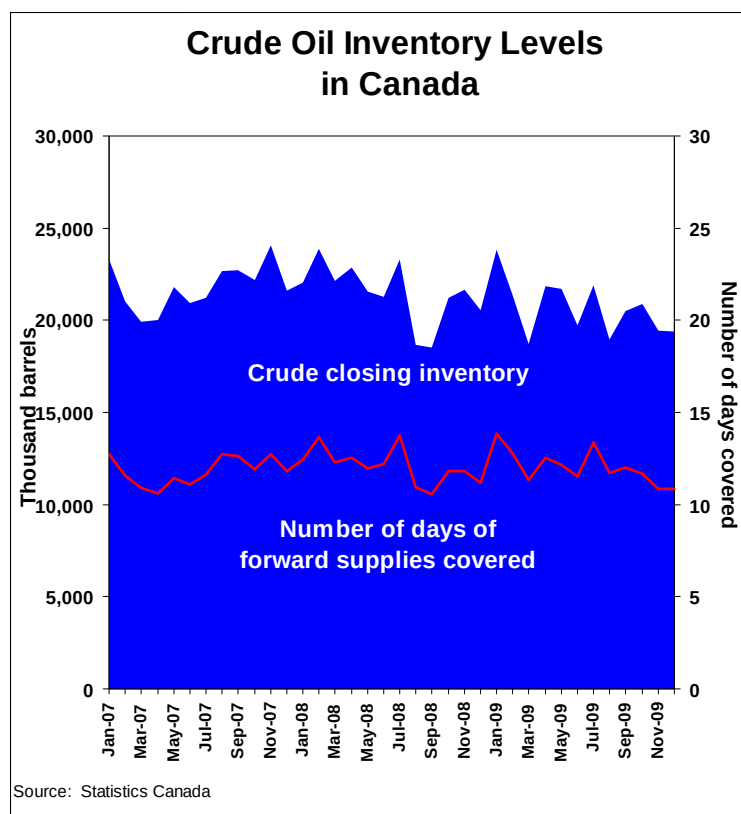
West Texas Intermediate Crude oil (WTI) is a benchmark crude oil for the North American market, and Edmonton Par and Western Canadian Select (WCS) are benchmarks crude oils for the Canadian market. Both Edmonton Par and WTI are high-quality low sulphur crude oils with API gravity levels of around 40°. In contrast, WCS is a heavy crude oil with an API gravity level of 20.5°.

Oil sands crude oil does not flow naturally in pipelines because it is too dense. A diluent is normally blended with the oil sands bitumen to allow it to flow in pipelines. For the purpose of meeting pipeline viscosity and density specifications, oil sands bitumen is blended with either synthetic crude oil (synbit) and/or condensate (dilbit).

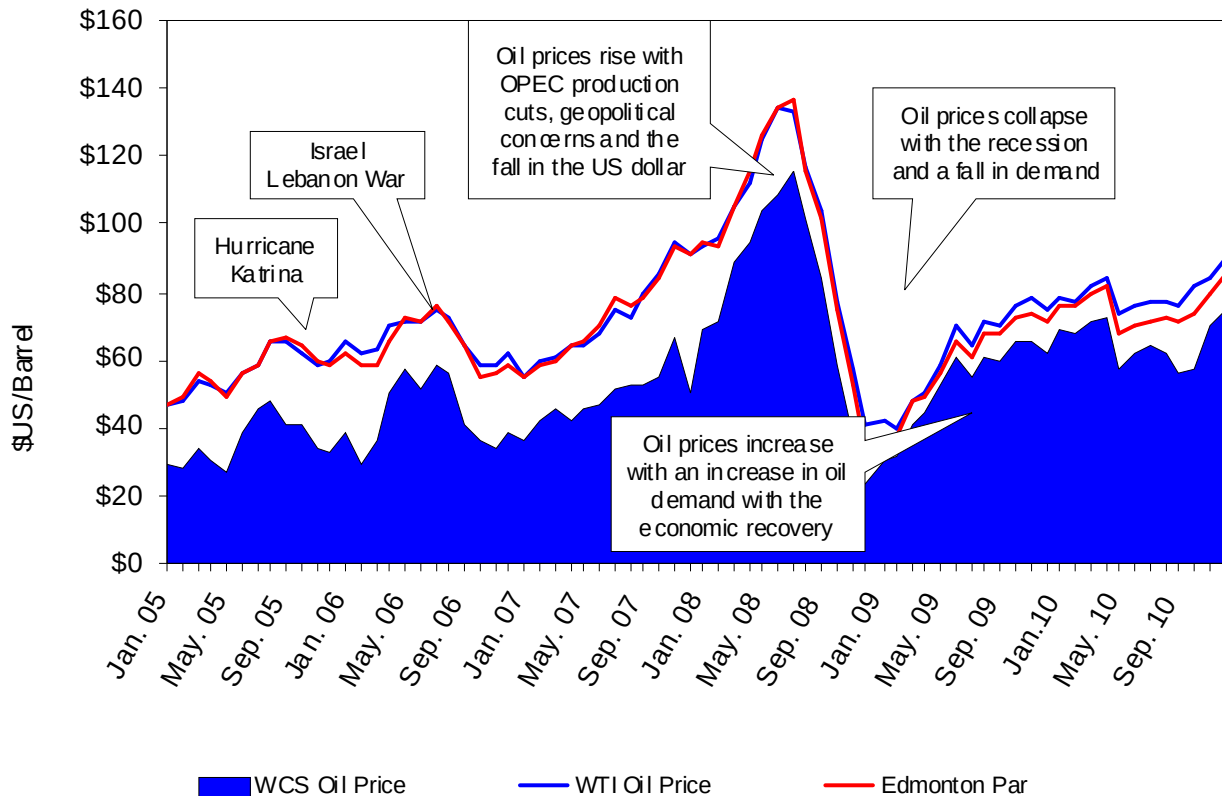
WCS is a dilsynbit (diluent – synthetic – bitumen) blend with an API gravity level of 20.5°. WCS has satisfied the criteria to become a benchmark with production volumes of around 250,000 barrels per day and may grow from this number, whereas WTI is declining from its current volume of 300,000 - 400,000 barrels per day.

The graph on the next page shows monthly WTI, Edmonton Par and WCS crude oil prices for the January 2005 to December 2010. WTI and Edmonton Par crude oils are sold at prices in close proximity to each other as these crude oils are of similar quality.

Since WCS is a heavy sour grade, it requires



Crude Oil Prices



Source: Energy Information Administration and NRCan

more time and energy to refine it. As a result, WCS is sold at a discount to WTI. Between 2006 and 2008, the average annual differential between WTI and WCS was between \$20 and \$24 per barrel. Since the fall of 2008, the price differential between WTI and WCS narrowed with growing demand for heavier Canadian crude oil from US refineries. By 2009, the price differential between WCS and WTI was only \$9.67 per barrel.

The higher price for heavier crude oils has improved the economics of developments such as the oil sands. By early 2009, with the recession driving crude oil prices down, \$100 billion in oil sands projects were on hold. However, with the recovery in oil prices, oilsands projects are now once again back on track for rapid growth. Within the last year, rising petroleum prices have prompted the re-start of a variety of oil sands mining and in-situ projects including: Suncor Energy's Firebag expansion, Imperial Oil's Kearl project, Cenovus' Narrows Lake project, Devon

Energy's Jackfish expansion, and ConocoPhillips and Total's Surmont project.

Volatile Crude Oil Prices

As seen in the graph, the January 2007 to September 2010 period was characterized by high oil price volatility (particularly in 07/08). WTI crude oil rose from a monthly average of \$US 54.50 per barrel in January 2007 to over \$US 133 per barrel by June of 2008.

A number of traditional factors contributed to the escalation in the price of crude oil such as:

- OPEC production cuts;
- High oil demand (particularly China);
- Reduced spare capacity and inventory levels;
- Oil price subsidies; and,
- Geopolitical concerns.

New emerging factors also had an effect:

- The declining value of the US dollar;
- The emergence of oil as a new investment class; and,

- Increased flows of money into the crude oil futures market (banks, hedge funds, and insurance companies).

The major drop in the price of oil that was experienced in the fall of 2008 was mainly a response to a drop in the demand for oil in the face of the recession and the financial crisis. The daily price of oil fell to a low of US\$30 per barrel in December 2008. Oil prices rebounded, in the summer and fall of 2009, with the expectation of higher crude oil demand with the economic recovery. By the end of 2009, oil prices were trading at around US\$75 per barrel, and through November 2010, have remained in the \$80 per barrel range. In 2009, the price of crude oil averaged 62% of the price in 2008.

The Oil and Gas Division prepared an in depth report on the factors causing high oil price volatility. The [crude oil issues report](#) can now be seen on Natural Resources Canada's reports and publications website⁸.

Crude Oil Imports, Exports and Trade Revenues

For geographic and economic reasons, oil is exported from the west and the Atlantic offshore and imported into eastern and central Canada. On balance, Canada is a large and growing net oil exporter. Domestic sources supply all of the crude oil used in Western Canada and close to three quarters of Ontario's crude oil demand. Most crude oil demand in Quebec (365 kb/d in 2009) and the Atlantic provinces (372 kb/d in 2009) is met with imports.

The table at the top right shows Canadian oil imports by source for 2008 and 2009. In 2008, Canada imported 846 kb/d of crude oil. With the recession, imports fell by 5% to 807 kb/d in 2009. In 2009, 360 kb/d or 45% of Canada's crude oil imports came from OPEC member countries. Twenty-seven percent of Canada's crude oil imports came from the North Sea, and other regions accounted for the remaining 28% of imports.

The table at right compares Canada's crude oil exports across different US Petroleum Administration for Defence Districts (PADD). Canada exported 1.86 mb/d of crude oil in

Canadian Crude Oil Imports by Country (kb/d)			
Rank	Country	2008	2009
1	Algeria	196	149
2	Norway	143	122
3	United Kingdom	120	93
4	Saudi Arabia	66	71
5	Angola	82	43
6	Nigeria	29	34
7	Venezuela	25	33
8	Iraq	60	26
9	Mexico	21	22
10	Russia	26	18
	All others	78	196
Total Canadian Imports		846	807

Source: Statistics Canada Energy Statistics Handbook

2008. In 2009, Canadian crude oil exports were slightly higher at 1.88 mb/d.

The table below also compares exports to the US with exports to other countries, showing that more than 99% of total Canadian crude oil exports are destined for the US market. More than three quarters of Canada's crude oil exports go to the US Mid-West region and US Rocky Mountain regions.

Canadian Crude Oil Exports by Destination (kb/d)		
Export Area	2008	2009
US East Coast	249	225
US Mid-West	1,118	1,158
US Gulf Coast	9	14
US Rocky Mountain Region	318	313
US West Coast	153	158
Total Exports to US	1,846	1,868
Exports to other Countries	8	14
Total Exports	1,856	1,882

Source: Statistics Canada Energy Statistics Handbook

In 2009, Canadian export revenues from crude oil of \$43 billion were 36% lower than its 2008 level (\$67 billion). However, unlike with natural gas, this reduction in export revenues was not coupled with a reduction in export volumes. In 2009, at 687 million barrels per year, crude oil export volumes were up 1% from its 2008 level (679 million barrels).

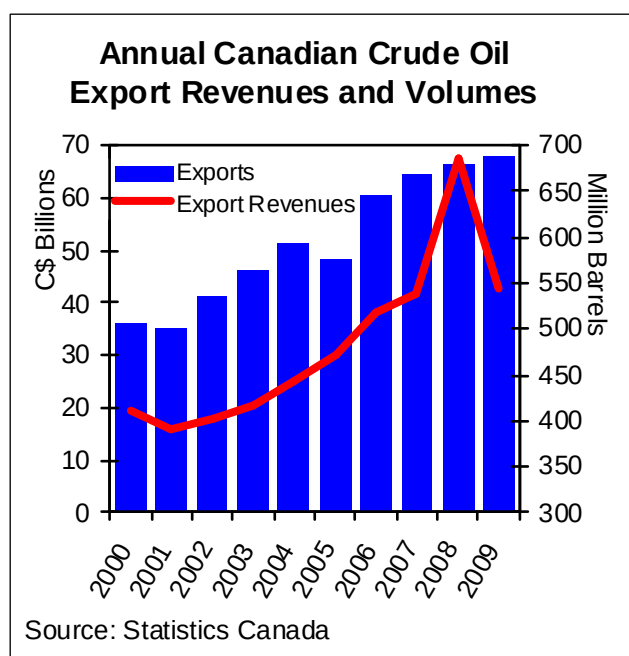
⁸ The report titled "Review of Issues Affecting the Price of Crude Oil" can be downloaded at:
<http://nrcan.gc.ca/eneene/sources/crubru/pcopdp/index-eng.php>

Crude Oil Exports and Imports			
	2008	2009	Change
Exports (Gross)			
Volume (million barrels)	679	687	+1%
Avg. Export Price (C\$/B)	\$99.25	\$66.35	-33%
Export Revenue (billion)	\$67.4	\$42.8	-36%
Imports (Gross)			
Volume (million barrels)	310	295	-5%
Avg. Import Price (C\$/B)	\$109.65	\$72.05	-34%
Import Expense (billion)	\$34.0	\$21.2	-38%
Net Exports			
Volume (million barrels)	369	392	+6%
Net Export Revenue (billion)	\$33.4	\$21.6	-35%

Source: Statistics Canada, Energy Statistics Handbook

The lower revenue figures are therefore not a reflection of less product being exported, but of the lower price of Canadian crude oil in 2009 compared with 2008. In 2009, the average Canadian crude oil export price, at \$66.35 Cdn/bl, was one third lower compared to the average of \$99.25 Cdn/bl in 2008. The lower price for Canada's commodity exports had a major impact on Canada's annual trade balance – In 2009, it fell into deficit, for the first time since 1975. Lower prices for commodities led to trade deficits in the 2nd and 3rd quarters of 2010.

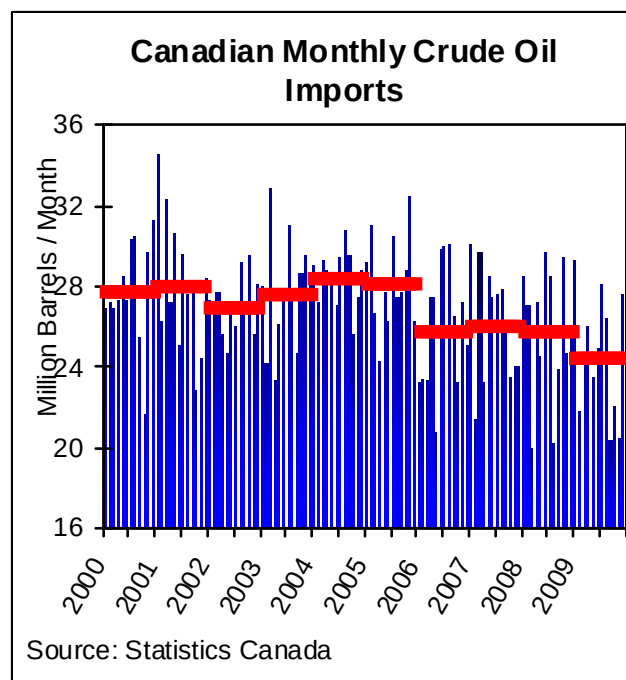
The drop in the value of crude oil also had a major impact on the Canadian dollar, which fell to 81 cents against the US dollar in December 2008. As crude oil prices recovered in 2009, the Canadian dollar approached par with the US



dollar. It is for this reason that the Canadian dollar is now commonly described as a “petro dollar”.

Canada's refineries import light sweet (low sulphur) crude oil which sells at a premium compared to the heavier crude oils which Canada exports to the United States. This explains the difference between the average import price for crude oil and the average export price for Canadian crude oil.

The figure above highlights both the monthly volatility of Canadian imports, as well as their seasonal pattern. Canadian crude oil imports typically increase to meet the peak demand for heating fuel during the winter months and gasoline demand during the peak summer driving season. In recent years, the overall demand for crude oil imports in Eastern Canada has been declining in response to increased use of domestic crude oil, the closure of the Petro-Canada refinery in Ontario, lower utilization rates and the effects of the 2008/2009 recession.



Review of 2009 – Natural Gas Market

Market Structure

The Canadian natural gas market is part of a continental market, and is affected by market conditions in both Canada and the US. In this market, natural gas flows seamlessly across borders via extensive pipeline networks connecting supply basins to demand centers. Regional prices, reflecting natural gas pipeline transportation costs, are established within this market. Unlike crude oil, there is no global price for natural gas.

Natural Gas Demand

Total North American demand for natural gas in 2009 was about 25.5 Tcf (trillion cubic feet) or about 70 Bcf/d (billion cubic feet per day). Canadian natural gas demand represents about 11% of the combined Canada-US demand. Core demand includes natural gas used for space heating in the residential and commercial sectors, while non-core demand includes the industrial and power generation sectors. The graph below shows the components of 2009 North American natural gas demand.

The table above summarizes North American natural gas demand for 2008 and 2009. US demand fell in 2009, by 2.1%, largely as a result of the economic downturn. Canadian demand was also down, albeit by less than 1%. Overall, total North American demand was down 2% in 2009.

North American Natural Gas Demand				
	2008		2009	
	Bcf	Y/Y Chg.	Bcf	Y/Y Chg.
US Residential	4,872	3.2%	4,739	-2.7%
US Commercial	3,136	4.1%	3,095	-1.3%
US Industrial	6,650	0.0%	6,090	-8.4%
US Electric	6,668	-2.5%	6,888	3.3%
US Other ⁽¹⁾	1,900	1.5%	1,928	1.5%
Total US Demand	23,227	0.6%	22,739	-2.1%
US LNG Exports	39	-19%	33	-15%
US Exports to Mexico	365	25%	338	-7%
Total US Disp'n	23,631	0.8%	23,111	-2.2%
Cda. Residential	627	1.5%	626	-0.2%
Cda. Commercial	457	2.5%	468	2.4%
Cda. Ind. & Power Gen.	1,549	1.8%	1,534	-1.0%
Cda. Other ⁽²⁾	136	-16.6%	115	-15.4%
Total Canadian Gas Sales	2,719	0.7%	2,743	-0.9%
Total N.A. Demand	25,996	0.6%	25,482	-2.0%
Total N.A. Disposition	26,400	0.8%	25,854	-2.1%

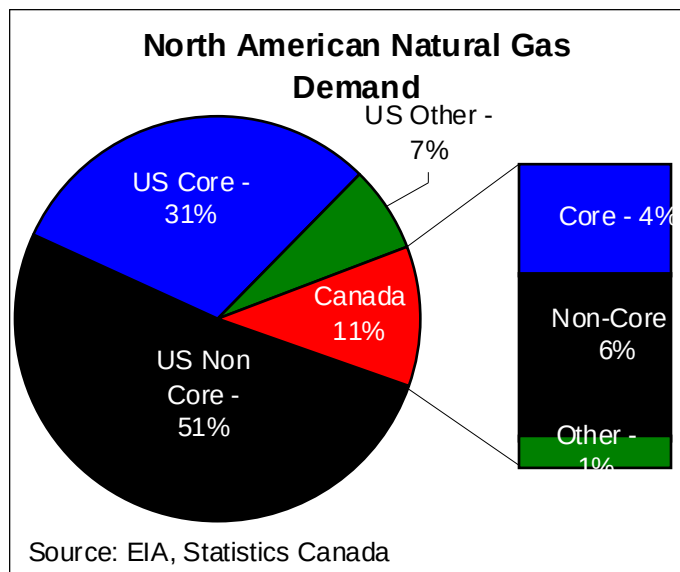
Sources: Statistics Canada, EIA

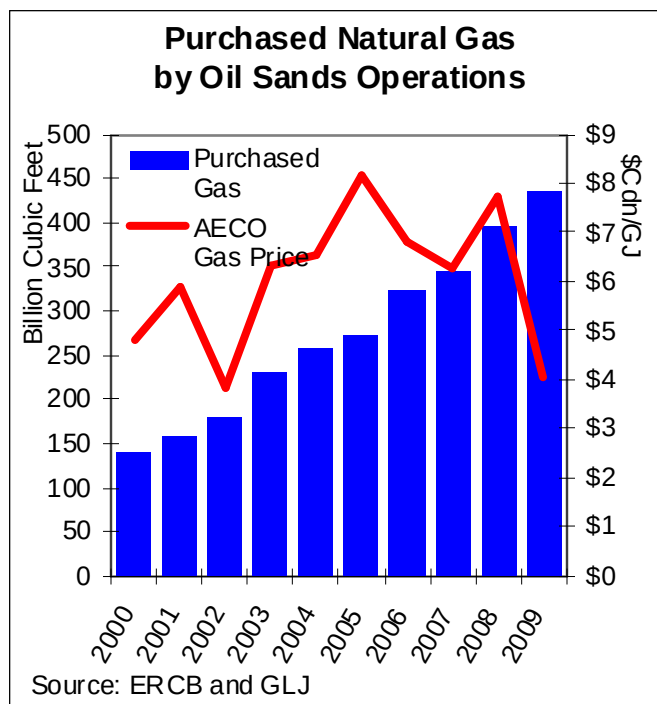
Notes: (1) US Other includes pipeline and distribution use, lease and plant fuel, and vehicle use. (2) Canadian other consists mainly of pipeline compressor fuel.

Demand for natural gas in the industrial sector is largely derived demand, e.g. demand that arises due to the demand for another good or service.

As illustrated in the figure on the following page, expanding oil sands operations continue to increase their demand for natural gas. Purchased gas by the oil sands is now 432 Bcf/year or 1 Bcf/d. Alberta's Energy Resources Conservation Board (ERCB) expects this demand to double again by 2020. Low natural gas prices continue to make natural gas an economical fuel to use in oil sands operations.

Oil sands operations consume more than just purchased gas. Oil sands upgrading operations also produce their own natural gas that is used on site. The in situ operations also produce solution gas from bitumen wells. Therefore, total gas consumed in this industry is the sum of purchased gas, process gas, and solution gas produced at bitumen wells. Total gas use





by the oil sands sector, including gas used by the electricity cogeneration units on site at the oil sands operations, was 681 Bcf in 2009.

Natural gas for power generation remains the primary driver of North American demand growth since 2000. US demand for natural gas to generate electricity increased 32% since 2000 and now accounts for 26% of total North American demand. Despite volatile natural gas prices, the power generation sector has shown an increasing appetite for natural gas as environmental and cost pressures make natural gas-fired generators an attractive option for power generation.

A contributing factor to natural gas demand growth in the power generation sector in recent years are warmer summers, particularly in the US, which drives increased summer air conditioning requirements, and thus, increases gas demand for power generation.

Natural Gas Supply

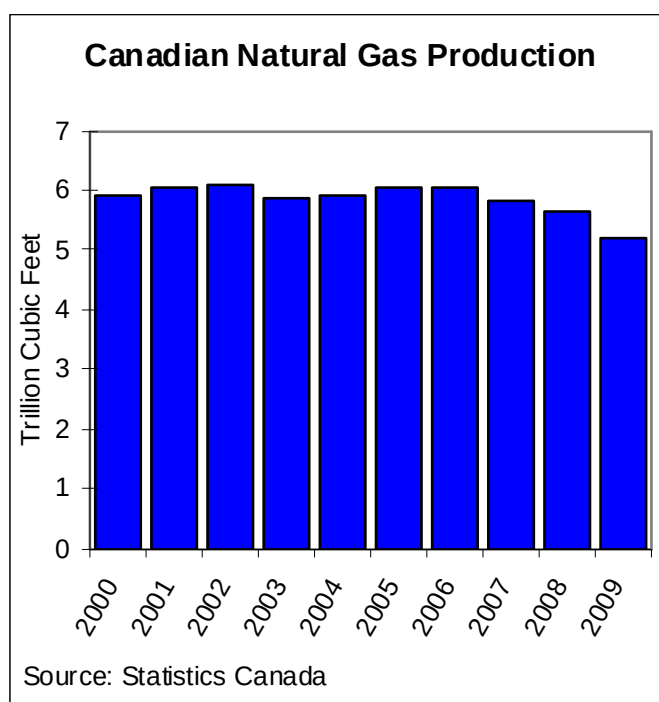
2008 was an interesting year for North American natural gas production. US production increased 5% largely on account of surging shale gas production. Meanwhile, Canadian production declined 4% owing to the maturing Western Canada Sedimentary Basin (WCSB). The trend continued in 2009 when US production increased 3% while Canadian production declined a further 7%. Refer to the table below for a split of each region.

North American Natural Gas Supply				
	2008	2009	09 vs. 08	
	Bcf	Bcf	Bcf	%
Alaska	398	397	-2	0%
Fed. Offshore GoM	2,327	2,433	106	5%
Louisiana	1,377	1,532	154	11%
New Mexico	1,446	1,404	-42	-3%
Oklahoma	1,913	1,858	-55	-3%
Texas	6,921	6,851	-70	-1%
Wyoming	2,275	2,359	84	4%
Other states	4,582	5,059	478	10%
Total US Prod'n	21,240	21,893	653	3%
Western Canada	5,459	5,082	-377	-7%
Scotian Shelf	161	124	-37	-23%
Canadian Prod'n	5,620	5,206	-414	-7%
Total N.A. Prod'n	26,860	27,099	239	1%
US LNG Imports	352	452	100	29%
US Mexican Imports	43	28	-15	-35%
Total N.A. Supply	27,255	27,579	324	1%

Source: EIA, Statistics Canada

In 2009, combined North American domestic natural gas production increased 239 Bcf (1%) to reach 27 Tcf. This is the fourth consecutive year of production increases and solidifies the trend of rising production.

The low price of natural gas is not impeding production of natural gas, as companies are actively pursuing shale gas production, which appears to still be economic. Canadian natural gas production peaked in 2002. Production fluctuated over the years, however recent years marked fairly significant declines.



As illustrated in the graph on the previous page, Canadian natural gas production was down nearly 6% in 2008 and a further 7% in 2009.

The Canadian supply picture stands in stark contrast to the US, which continues to record significant growth in gas production. Starting in 2006, the US had very strong year over year production growth including by 5% in 2008 and another 3% in 2009.

The surging production is primarily attributable to the improved economics and technology associated with unconventional gas, particularly shale gas.

2009 Top 10 Canadian Natural Gas Producers			
Rank	Company	Bcf/d	Percent
1	EnCana Corporation	1.99	13%
2	Canadian Natural Resources	1.29	8%
3	ConocoPhillips Canada	1.06	7%
4	Talisman Energy Inc.	0.72	5%
5	Devon Energy Corp.	0.67	4%
6	Husky Energy Inc.	0.54	4%
7	Shell Canada	0.53	3%
8	Penn West Energy Trust	0.44	3%
9	Suncor Energy	0.37	2%
10	Apache Canada	0.36	2%
Total Canadian Production		15.28	100%

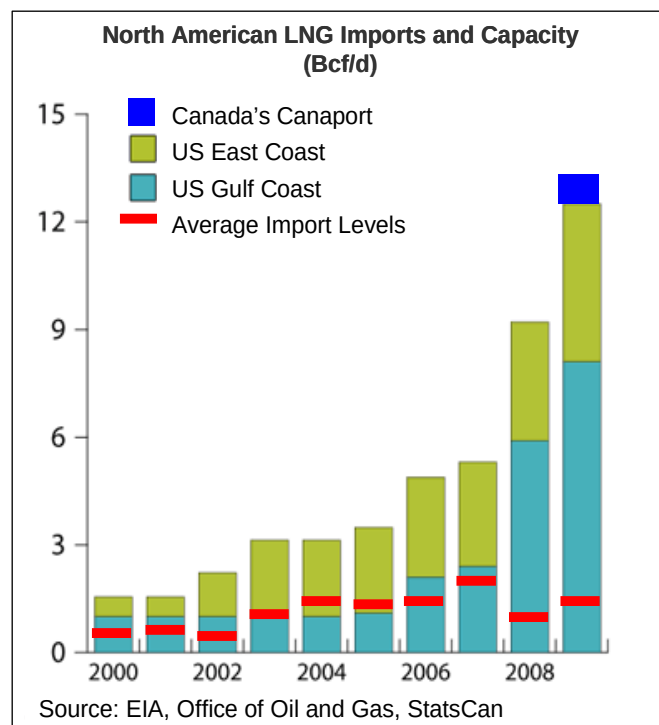
Source: Oilweek Magazine, July 2010.

The table above shows the top ten natural gas producers in Canada. While there are hundreds of natural gas producers in Canada, the top ten control 52% of production.

Liquefied Natural Gas (LNG)

For North America as a whole, one consequence of growing domestic natural gas production and falling prices is reduced Liquefied Natural Gas (LNG) imports. LNG imports were down over 50% in the US in 2008 and exhibited only a very modest recovery in 2009.

The US LNG imports and capacity graph highlights the huge excess of regassification capacity of LNG import facilities. There are also market participants who believe that Canadian shale gas production will eventually increase. These market participants are supporting a



Canadian LNG Export project (Kitimat LNG), which would export liquefied shale gas to Asia.

The Canaport LNG terminal is currently Canada's only operational LNG import facility with a capacity of 1.2 bcf/d. All other LNG import and export proposals have been cancelled or delayed on account of:

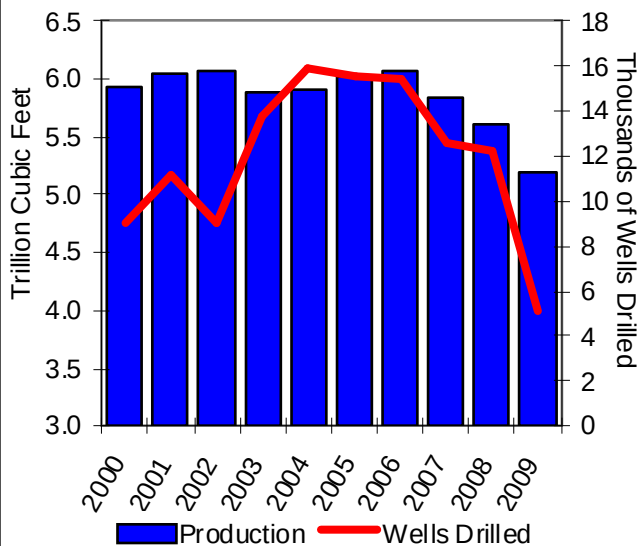
- 1) difficulties securing long term supply commitments;
- 2) concerns over existing excess regassification capacity in North America; and,
- 3) the prospects for domestic shale gas as a new long term source of natural gas.

Natural Gas Wells Drilled

Total gas well completions for Western Canada in 2009 collapsed in comparison to previous years. Total gas wells drilled for 2009 set a 10-year low at 5,082 compared to 12,361 the year before, as shown in the graph on the following page. This decline is largely due to the depressed price of natural gas.

For most of the past decade, in both Canada and the US, increased drilling was needed just to sustain production levels. For the US, this trend came to an end in 2009 when production increased despite a steep drop in the number of wells drilled (down 44% from 2008 levels). The graph on the following page clearly illustrates this reversal.

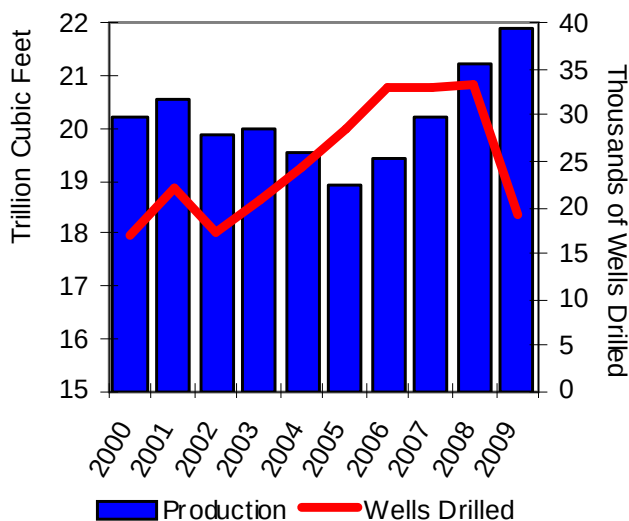
Canadian Natural Gas Production and Wells Drilled



Source: Statistics Canada

This counter-intuitive result is in part explained by the shift in production from conventional sources to unconventional sources, shale gas in particular. Shale gas drilling tends to be highly productive, especially in the first year, and uses horizontal drilling techniques which have a higher rate of production. In Canada, where shale gas development is still in a nascent stage, dramatic declines in drilling led to equally dramatic declines in production.

US Natural Gas Production and Wells Drilled



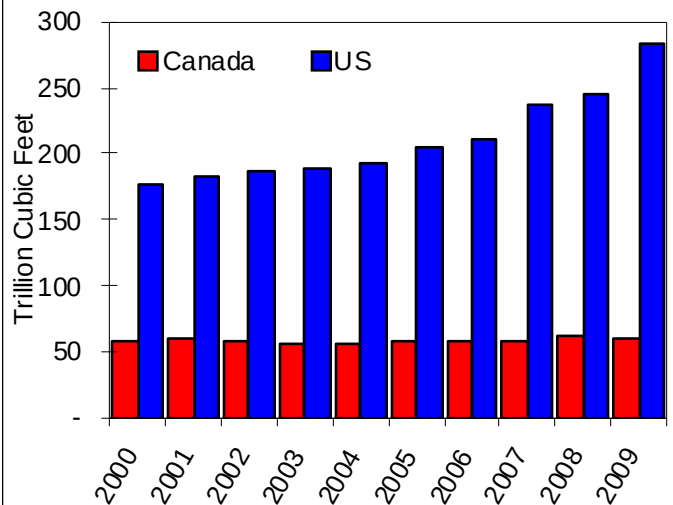
Source: EIA

Natural Gas Reserves

Proved reserves of natural gas are estimates of the quantities of gas remaining in known, drilled reservoirs, that are economic to produce, and are connected, or can easily be connected, to pipelines and markets. As of year-end 2009, Canadian and US combined reserves totalled nearly 345 Tcf, with 61 Tcf in Canada and 284 Tcf in the US. The graph below shows North American natural gas reserves since 2000. Since 1999, US reserves have increased each year, reversing the previous trend of decline.

Based on North American production of about 26 Tcf per year, the North American reserve-to-production ratio (R/P ratio) is over 13 years. In other words, if no new gas reservoirs are found, US and Canadian reserves would last about 13 years assuming current production rates.⁹

North American Proved Natural Gas Reserves



Source: CAPP, EIA

In 2008, Canada posted the largest net reserve addition in over 25 years. Canadian reserves for 2008 jumped 4.3 Tcf (or over 7%). Most of the net reserve additions were attributed to British Columbia and increased optimism surrounding shale plays. This is a concrete example of evidence to support the theory that Canadian gas production will begin to increase

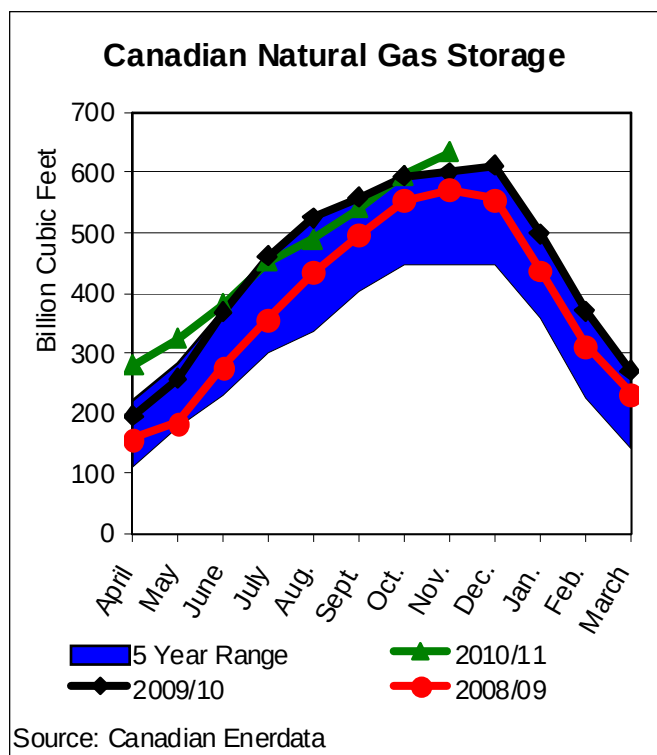
⁹ New reserves are found every year. Proved reserves change, according to the following formula: proved reserves at start of year + reserve additions (including revisions, whether positive or negative, to previous estimates) during the year - production during the year = proved reserves at end of year.

in the future. Canadian reserves declined about 1.5% in 2009, largely on account of very low prices.

US natural gas reserve growth is primarily due to unconventional natural gas. In the two years the EIA has collected data on shale gas reserves, shale gas reserves increased 50% and now account for 9% of total US reserve estimates.

Natural Gas Storage

Natural gas storage is used to help balance seasonal variations in demand with relatively constant supply. In the spring, summer and fall, when natural gas demand is low, gas is injected into storage. Storage volumes normally peak in the fall. In winter, volumes are drawn down, reaching a low point in the spring.



Local distribution companies (LDCs) inject gas into storage, and withdraw it in winter to meet peak winter demand loads in the residential and commercial sectors. Storage also allows LDCs to use contracted, long-haul pipeline capacity at relatively stable rates all year.

Producers use storage injections or withdrawals to balance fluctuating production levels with contractual supply obligations. Storage is also used by both buyers and sellers of natural gas

to capture price arbitrage opportunities (e.g. inject natural gas into storage when prices are low, and withdraw natural gas and sell it when the price is higher).

Depleted oil or natural gas reservoirs and salt caverns are commonly used to store natural gas. Natural gas storage capacity in Canada is spread across five provinces with the majority in Alberta and Ontario. Western Canadian storage is used primarily for managing supply while storage in eastern Canada is primarily for balancing Ontario's seasonal demand fluctuations.

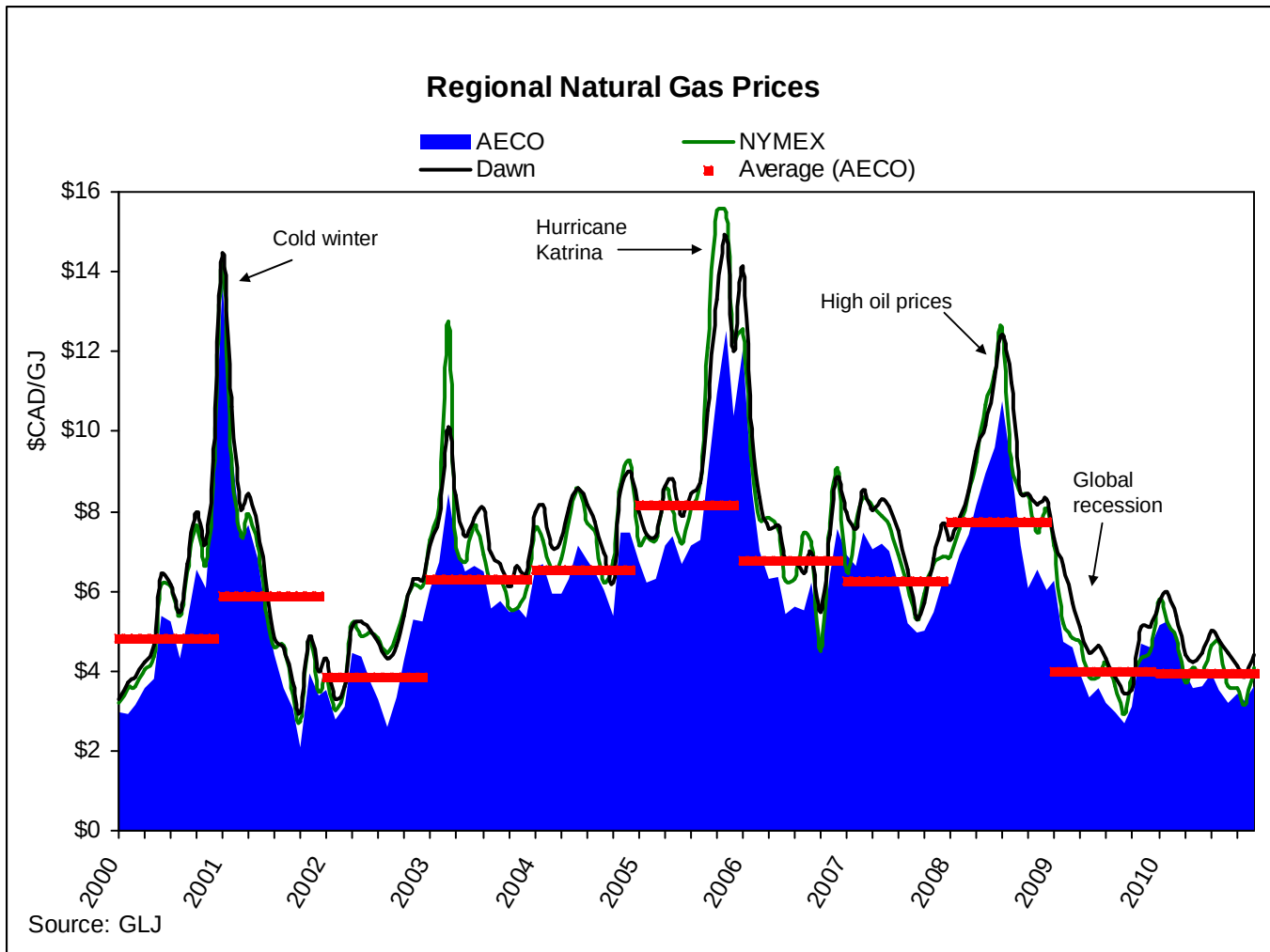
The illustration depicts the 2008/09, 2009/10 and the beginning of the 2010/11 storage seasons, as well as the 5 year maximum and minimum levels for Canada. The recent glut of natural gas on the market sent storage levels in Canada well above previous 5-year maximums. Ballooning storage volumes were attributable to low natural gas prices, reduced industrial demand, and surging US production.

Natural gas in storage strongly influences natural gas prices. Traditionally, there is an inverse relationship between natural gas storage levels and prices. High storage levels promote lower prices, and lower storage levels promote higher prices. It is no coincidence that the record low prices experienced in the last 24 months coincided with record high volumes of natural gas in storage.

Natural Gas Prices

Canadian natural gas prices are unregulated, and change according to buyer and seller perceptions of supply and demand fundamentals. These fundamental factors can be short-term in nature or longer-term (e.g. expected cost of finding new natural gas over the next five years).

As illustrated in the figure on the next page, natural gas prices tend to be very volatile and are prone to price spikes. Many factors are built into the market clearing price for natural gas, including expectations, supply and demand. In the short term, there are also major shocks that can cause natural gas prices to spike, such as cold winters, hurricane's disrupting supply (e.g. hurricane Katrina), exceptionally high oil prices (e.g. gas is a substitute), or most recently the global economic recession.



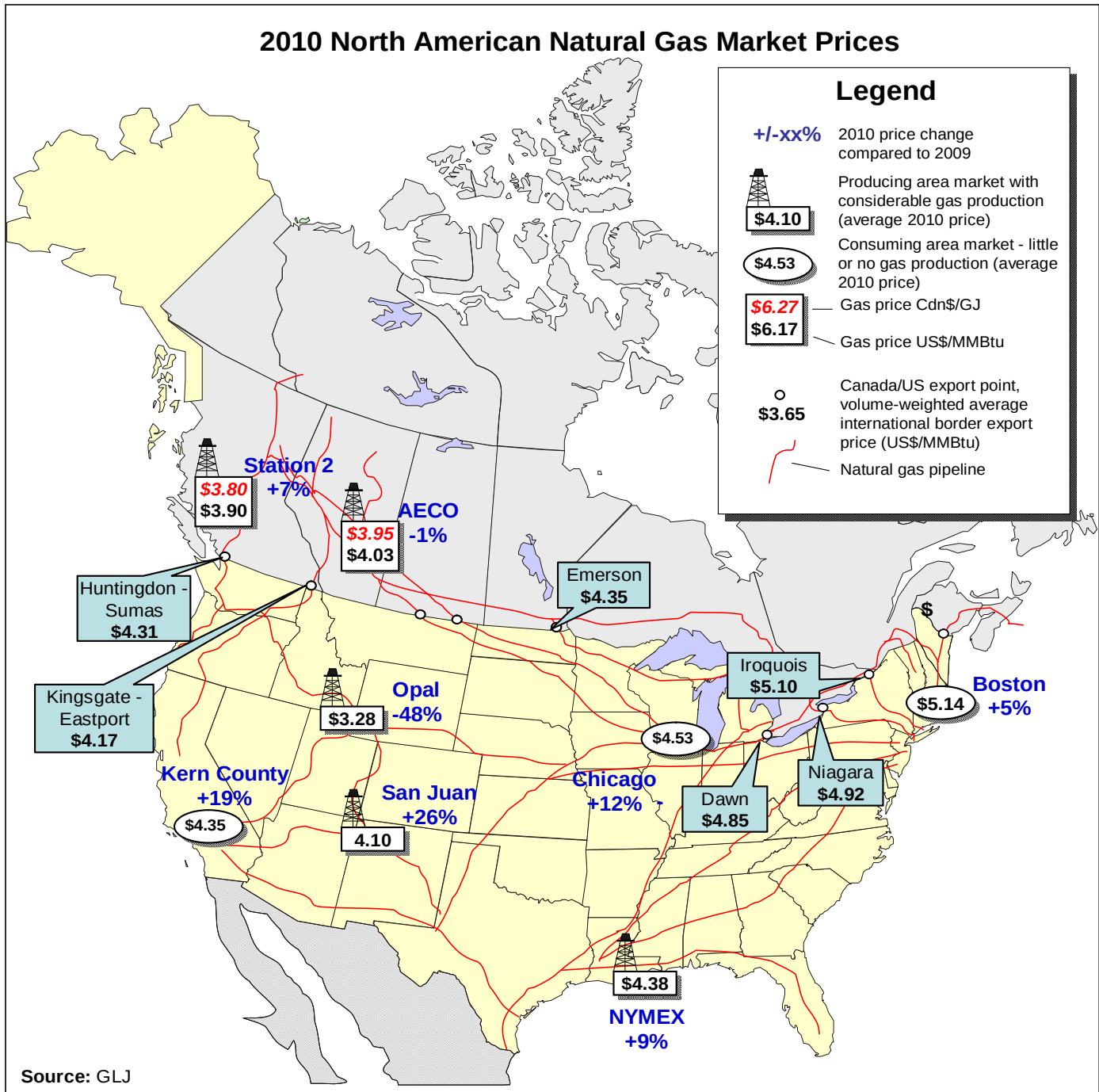
As a consequence of reduced natural gas demand (due to the economic recession), plummeting oil prices and surging shale gas production; natural gas prices collapsed in the summer of 2009. Natural gas prices plunged to record lows of CAD \$3/GJ in the fall of 2009, down considerably from the CAD\$11/GJ experienced during the summer 2008. Canadian natural gas prices in 2010 remained low and fluctuated in the \$3–\$6/GJ range. The graph also clearly shows how regional natural gas prices track each other, with differences in price primarily a reflection of transportation costs, and whether an area is a producing area which “exports” gas (low prices) or a non-producing area which must “import” gas from far away (high prices).

The map on the following page provides average annual natural gas prices at various producing basins, market hubs, consumption markets and export points in North America. Prices are simple 12-month averages. Average annual AECO natural gas prices were virtually

unchanged between 2009 and 2010, at about \$3.95/GJ.

Prices in 2009 and 2010 were low both in absolute terms, and also relative to crude oil prices. The low natural gas prices can be attributed to both the global economic downturn (lower demand) and also the lagged effect of last year’s drilling and production increases in the US (higher supply).

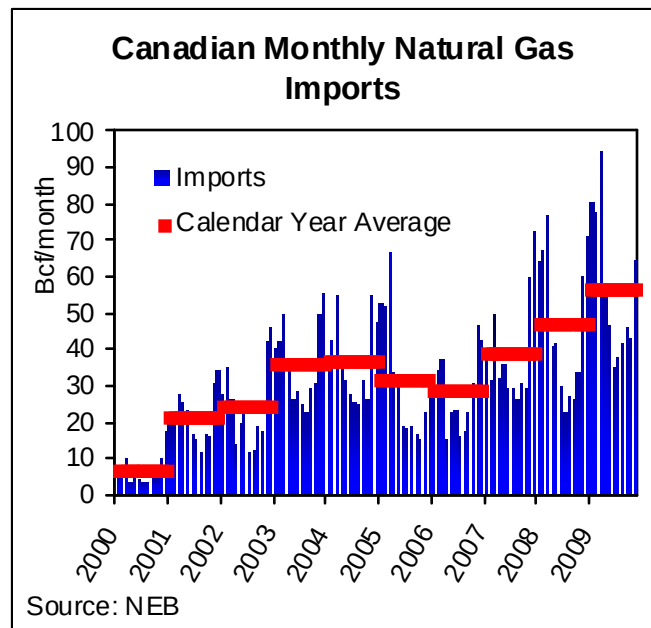
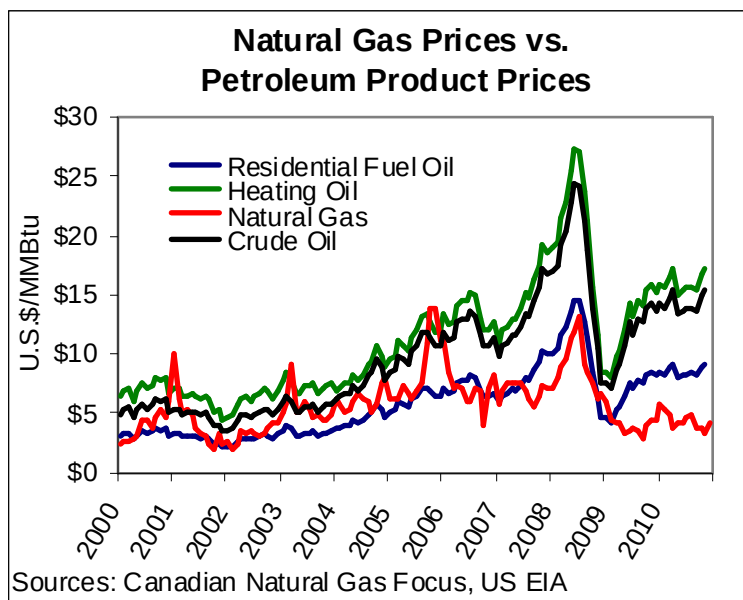
North American natural gas prices were historically strongly influenced by world crude oil prices and North American petroleum product prices. For years, North American natural gas prices (e.g., the NYMEX Henry Hub price) varied within a price band set on the low end by the price per MMBtu of residual fuel oil, and on the high end by the price per MMBtu of distillate. The relationship held on account of major industrial consumers being able to switch fuels on relatively short notice.



This price relationship was relatively robust through to about 2006. However, natural gas and oil have decoupled. Surging oil prices, combined with abundant North American natural gas supplies, and resultant low prices, have kept natural gas prices well below residual fuel oil prices in recent years. The decoupling of oil products and natural gas prices suggests that all industrial consumers who are able to switch to natural gas have

already done so. Furthermore, while oil products are priced on a global market, natural gas is still predominantly a continental commodity.

The expectation that oil and gas prices will remain decoupled is fuelling industry efforts to promote the use of natural gas as a cheaper and environmentally friendly alternative for transportation.



Natural Gas Imports, Exports and Revenues

Canada produces natural gas in excess of what is required for domestic consumption. Canada exports about 63% of its gas production, all of which goes to the US. In 2009, 87% of natural gas imported into the US came from Canada.

The table below summarizes Canadian natural gas imports and exports for 2008 and 2009. In 2009, Canadian gas export volumes declined by 11%. Export prices and revenues fell much harder, down 47% and 53% respectively. The decline in export volume was the direct result of falling Canadian natural gas production. As production falls, exports tend to fall, rather than domestic consumption of gas. The resulting drop in natural gas export revenues led to a major decline in Canada's trade balance, as is illustrated in the graph at right.

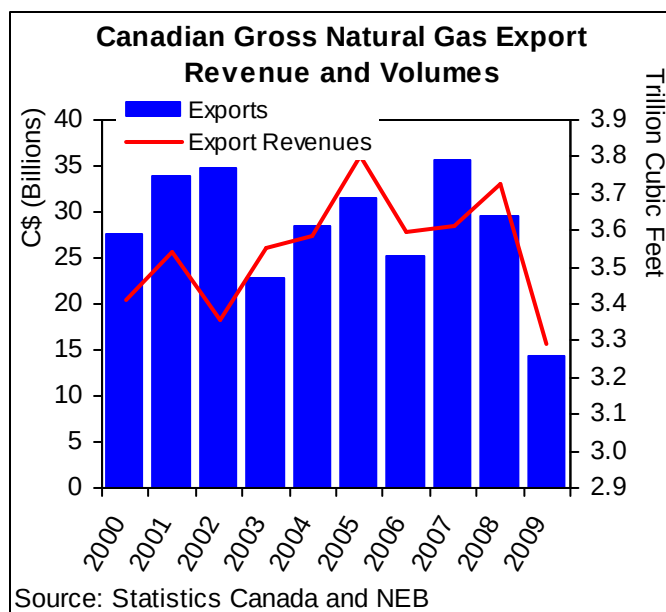
Natural Gas Exports and Imports			
	2008	2009	Change
Exports (Gross)			
Volume (Tcf)	3.6	3.3	-11%
Avg. Export Price (C\$/GJ)	\$8.41	\$4.42	-47%
Export Revenue (billion)	\$33.1	\$15.5	-53%
Imports (Gross)			
Volume (Bcf)	562	702	25%
Avg. Import Price (C\$/GJ)	\$8.59	\$4.85	-44%
Import Expense (billion)	\$5.17	\$3.63	-30%
Net Exports			
Volume (Bcf)	3,083	2,554	-17%
Net Export Revenue (billion)	\$27.9	\$11.9	-57%

Source: NEB, Statistics Canada

The majority of natural gas imports are from the US. However, in June 2009, Canada received its first LNG cargo at the Canaport terminal in Saint John, New Brunswick.

Imports in 2009 were at a record level of 702 Bcf, a 25% increase over 2008 levels. Some of the gas exported from Canada is re-imported. Natural gas imports have been increasing over time as purchasers in Southern Ontario find it cheaper to access gas from the US.

The graph above highlights both the volatility of imports and their seasonal pattern. Natural gas imports typically double during the colder months to meet peak Ontario and Quebec heating demands. The graph also illustrates Canada's increasing reliance on US imports.



Review of 2009 – Petroleum Products Market

Market Structure

Canadian petroleum product prices are essentially set in a global market. For example, Canadian wholesale gasoline prices are driven by US benchmark prices, such as the New York Harbour price. These US benchmark prices reflect the international crude oil price and such factors as seasonal demand and inventory levels. Canadian wholesale prices must remain competitive with these US benchmark prices. This is because if Canadian refiners' prices (for products) are lower, products will flow out of the country. If refiners' prices are higher, marketers will import lower priced products. The price of crude generally drives the prices of refined petroleum products. Despite this, crude oil and petroleum product prices can, at times, move in opposite directions.

Petroleum Product Demand

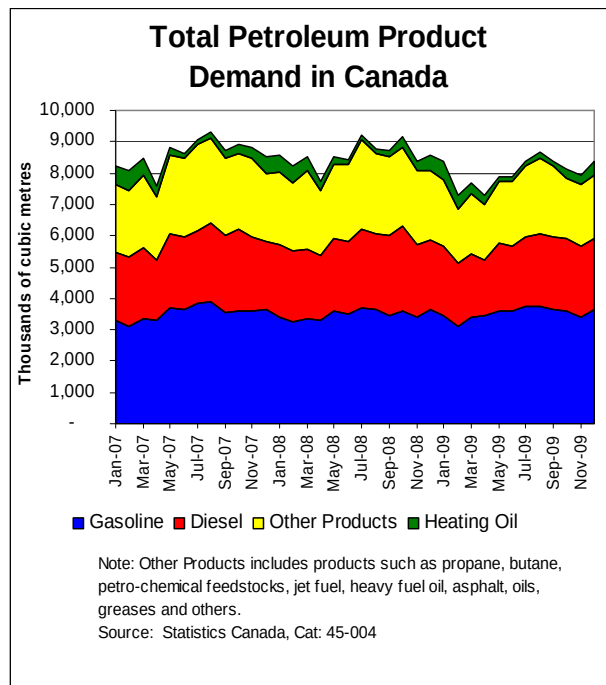
The demand for refined petroleum products (gasoline, diesel, furnace oil, and other products) in Canada fluctuates along with seasonal demand (e.g. increased demand for gasoline during the summer, more heating oil used in winter).

Demand for refined products in Canada fell in 2008 and in 2009, with the worldwide economic slowdown. In 2009, total sales declined by 6.5 billion litres (40.6 million barrels) from the previous year, to 96.6 billion litres (607.2 million barrels).

Gasoline

In 2009, Canadians consumed 42.3 billion litres (266 million barrels) of gasoline, an increase of 0.6 billion litres (3.5 million barrels) from 2008. In 2008, gasoline consumption had dropped by more than 0.5 billion litres.

Demand for gasoline dropped in the latter part of 2008 and during the first quarter of 2009 as a result of the economic slowdown. Demand gradually shifted upward, with the traditional increase in demand for gasoline during the summer driving season. By year-end, gasoline

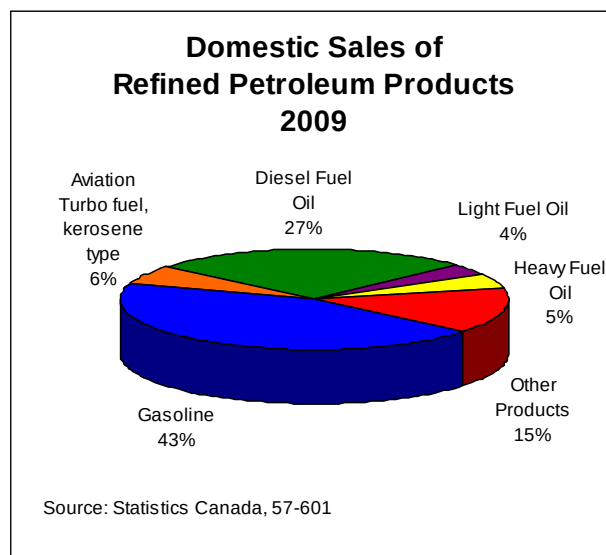


annual sales had increased back to the pre-2008 levels.

The Ontario market accounts for 39% of motor gasoline sales in Canada, followed by Québec (21%), Alberta (13%), British Columbia (11%), and Atlantic Canada (7%).

Diesel

Domestic sales of diesel fuel in 2009 were 26.0 billion litres (163.5 million barrels), 8% lower than the year before. Increased diesel demand in 2007 and 2008 reflected strong



growth in the Canadian economy and a growing proportion of diesel-powered vehicles in the fleet. Most of the growth was attributed to increased diesel use in the agricultural, mining and energy sectors of Western Canada. However, in 2009 the 7-year upward trend in diesel consumption ended, as a result of the recession.

In 2009, about 49% of the diesel sales occurred in Western provinces and territories, followed by Ontario (25%), Quebec (18%) and Atlantic Canada (8%).

Light Fuel Oil

Light fuel oil, also called heating oil or furnace oil, represents less than 4% of total petroleum product demand in Canada. Demand for light fuel oil, totalled 3.4 billion litres in 2009, 0.4 billion litres or 10% below 2008. This mainly reflects the loss of share to natural gas and electricity in the space heating markets of Ontario and Quebec. Since 2003, demand for light fuel oil has dropped by more than 35%.

Approximately 10% of Canadian homes use light fuel oil for heat. Heating oil sales are concentrated in Eastern Canada, with Atlantic Canada accounting for about 39% of domestic sales, Quebec at 32%, Ontario at 24% and the rest of Canada at 5% in 2008.

Atlantic Canada has the greatest dependence on oil for heating, with just over half of all homes using fuel oil to meet at least a portion of their heating needs. Prince Edward Island is by far the most dependent, with close to 85% of all households using heating oil. Despite the small percentage of households in Quebec and Ontario using heating oil to meet their space heating needs, heating oil sales in these two provinces represents more than half of Canada's fuel oil consumption, due to the size of the markets.

In Western Canada, natural gas is the dominant fuel for home heating. Only minimal volumes of light fuel oil are consumed in the prairies, and it accounts for only about 3% of the home heating market in British Columbia.

Other Refined Petroleum Products

Other refined petroleum products include heavy fuel oils (HFO), jet fuel, asphalt, petrochemical

feedstocks, coke, liquid petroleum gases (LPGs), lube oil and greases. In 2009, these accounted for about 36% of domestic petroleum product sales in Canada.

HFO demand in 2009 dropped by 23% (1.5 billion litres) to 4.9 billion litres. This represents 6% of total Canadian petroleum product demand. HFO is used by the industrial sector, for marine transportation, and for electricity generation.

In 2009, Quebec accounted for 41% of HFO demand and the Atlantic provinces 27%. Only about 32% of HFO demand comes from Ontario and Western Canada, as industries in these regions have more extensive pipeline access to Western Canadian natural gas supply.

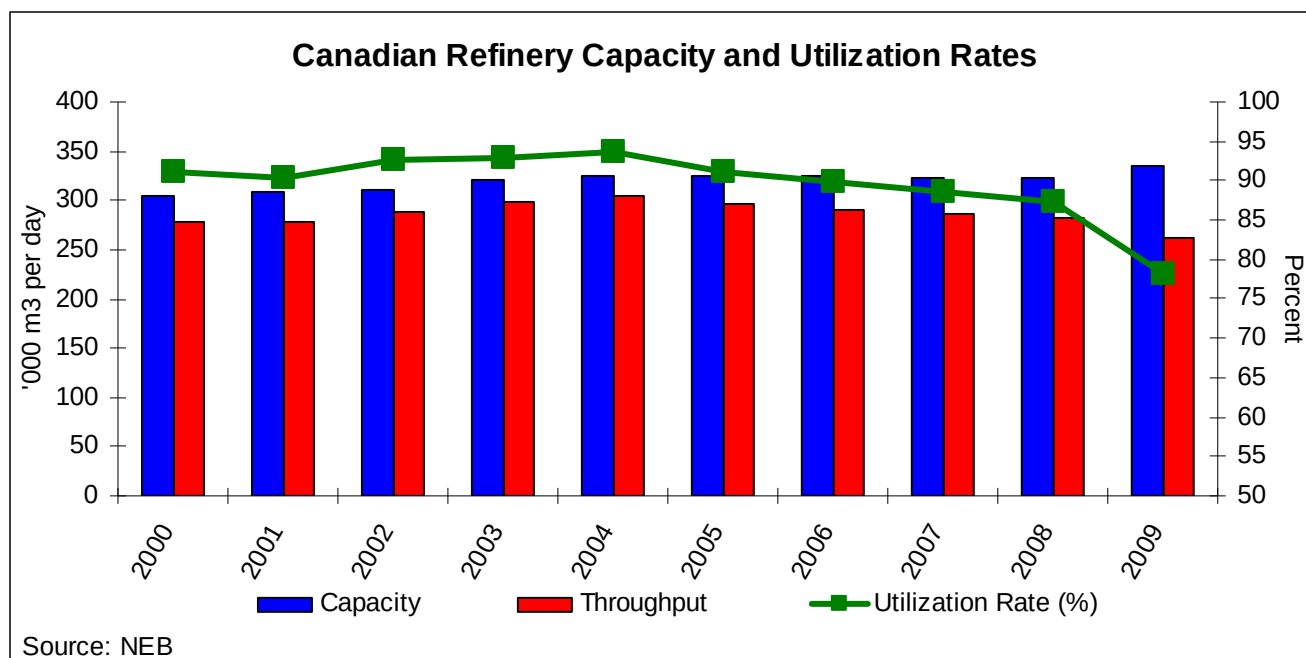
As the other refined products are usually relatively low volume specialty products with few substitutes, their demand is somewhat insensitive to the price of crude oil. However, consumption is not immune to the state of the economy, and demand for these products fell during this past recession.

Supply Overview

Petroleum products are produced by refining crude oil. In 2009, 11 companies operated refineries in Canada. Only Imperial Oil, Shell and Suncor Energy (Suncor and Petro-Canada merged in 2009) operate more than one refinery and market products nationwide. Other refiners generally operate a single refinery and market products in a particular region.

Regional refiners include Irving Oil (New Brunswick), North Atlantic Refining (Newfoundland and Labrador) and Ultramar (Quebec) in the east and Federated Co-op (Saskatchewan), Husky and Chevron (British Columbia) in the West.

Of the 19 refineries in Canada, 16 manufacture the full range of petroleum products. Husky's facility in Lloydminster, Alberta, and the Moose Jaw Asphalt plant in Moose Jaw, Saskatchewan, are primarily asphalt plants with limited production of other products. The Nova Chemicals facility in Sarnia, Ontario, is a petrochemical plant that also produces some distillate products.



There are three main refining centres in Canada (Edmonton, Sarnia and Montreal) but most provinces have at least one refinery. The exceptions are Manitoba and Prince Edward Island. Also, none of the three territories have refining capacity.

It is important to examine refining capacity and refinery utilization rates, as this data provides insight on the economics of building new refineries, and the state of petroleum product competition. Overall, while Canadian refinery capacity has increased slightly over the last decade – despite the closure of the Petro-Canada refinery in Ontario 2005 – the utilization rates has been dropping steadily since 2004. Utilization rates declined more significantly in 2009 because of lower demand for oil products, poor refining economics stemming from the economic downturn, and unscheduled shut-downs.

Regional Refinery Utilization Rates

The figure above shows Canadian refinery capacity and utilization rates. Based on weekly crude oil runs as reported to the National Energy Board, the Canadian refining industry typically operates at approximately 90% of capacity. However, in 2008 the industry operated at an average of 87% capacity. This decreased again in 2009 to 78% – the lowest refinery utilization rate in a decade. Essentially, low petroleum product demand due to the

economic downturn and poor refinery economics resulted in lower utilization.

In 2009, Atlantic Canada's utilization rates remained above the Canada average, in part due to continued exports to the US and to other Canadian provinces. However, refinery utilization rates in Western Canada dipped below 65% in 2Q09. This was the result of a number of refinery outages due to planned maintenance and unplanned shut-downs as well as upgrader problems, which interrupted crude supply to oil refineries.

With increasingly complex refineries, unplanned shutdowns have become more common than in the past few years – particularly in Western Canada. A single refinery outage can lead to a significant decrease in local petroleum product supply due to the geographically diverse nature of the country and the limited number of refineries in some regions.

Petroleum Product Inventory Levels

Over the past decades refiners have been rationalizing their operations in order to reduce costs and improve rates of return. A key element of this process has been the reduction of inventory levels to the minimum required to maintain normal operations.

To ensure secure supplies and distribution of petroleum products, refiners and marketers maintain inventories of the various products in strategic locations throughout the distribution

chain. If supplies of imported or domestic crude oil are interrupted for any reason, or if the product distribution system fails, companies can rely on commercial inventories to meet short-term needs while alternate arrangements are being made.

Inventory levels for some products, such as gasoline and light fuel oil, fluctuate significantly over the year. Demand for these products is very seasonal and at its peak can exceed the production capacity of refineries. Therefore, refiners anticipate peak consumption periods and build inventories in advance. Gasoline inventories increase during the first quarter of the year and are drawn down during the summer months to supplement refinery production. Light fuel oil stocks grow during the fall and are drawn during the coldest months of winter when demand is at its highest level.

Refiners also build up inventories of all products in advance of scheduled refinery maintenance (called turnarounds). Turnarounds can vary in frequency from annually to once every few years, and sometimes require the refinery to be completely shut down for a period of several weeks. Refiners prepare by building up product stocks that can be used during the turnaround. Canadian refiners typically maintain 21 to 26 days of gasoline and diesel supplies.

Petroleum Product Trade

Canadian production of gasoline, diesel, and other petroleum products, as well as domestic sales of those products, fluctuates with the seasons. Canadian production has historically been substantially higher than consumption. However at times, refinery down-time and high demand require imports, particularly gasoline.

Canadian Petroleum Product Regions

Canada has four distinct supply/demand regions for petroleum products:

- 1) Atlantic Canada,
- 2) Quebec,
- 3) Ontario and
- 4) Western Canada.

At times, product imports, exports and inter-regional transfers play a significant role in balancing supply and demand in each of these regions.

Regional Imports and Exports (Thousands of cubic metres)		
2009	Gasoline	Distillates*
Western Canada		
Net Production	12,580	13,196
Domestic Sales	14,141	12,862
Net Imports	1,185	- 587**
Net Inter-Regional Transfers	- 57**	- 316**
Ontario		
Net Production	10,182	5,666
Domestic Sales	16,354	7,343
Net Imports	478	- 564**
Net Inter-Regional Transfers	4,987	2,097
Eastern Canada		
Net Production	20,618	17,009
Domestic Sales	11,824	9,220
Net Imports	- 4,244**	- 5,908**
Net Inter-Regional Transfers	- 4,929**	- 1,782**
Canada		
Net Production	43,379	35,871
Domestic Sales	42,319	29,425
Net Imports	- 2,582**	- 7,059**

Notes: * Includes diesel and light fuel oil

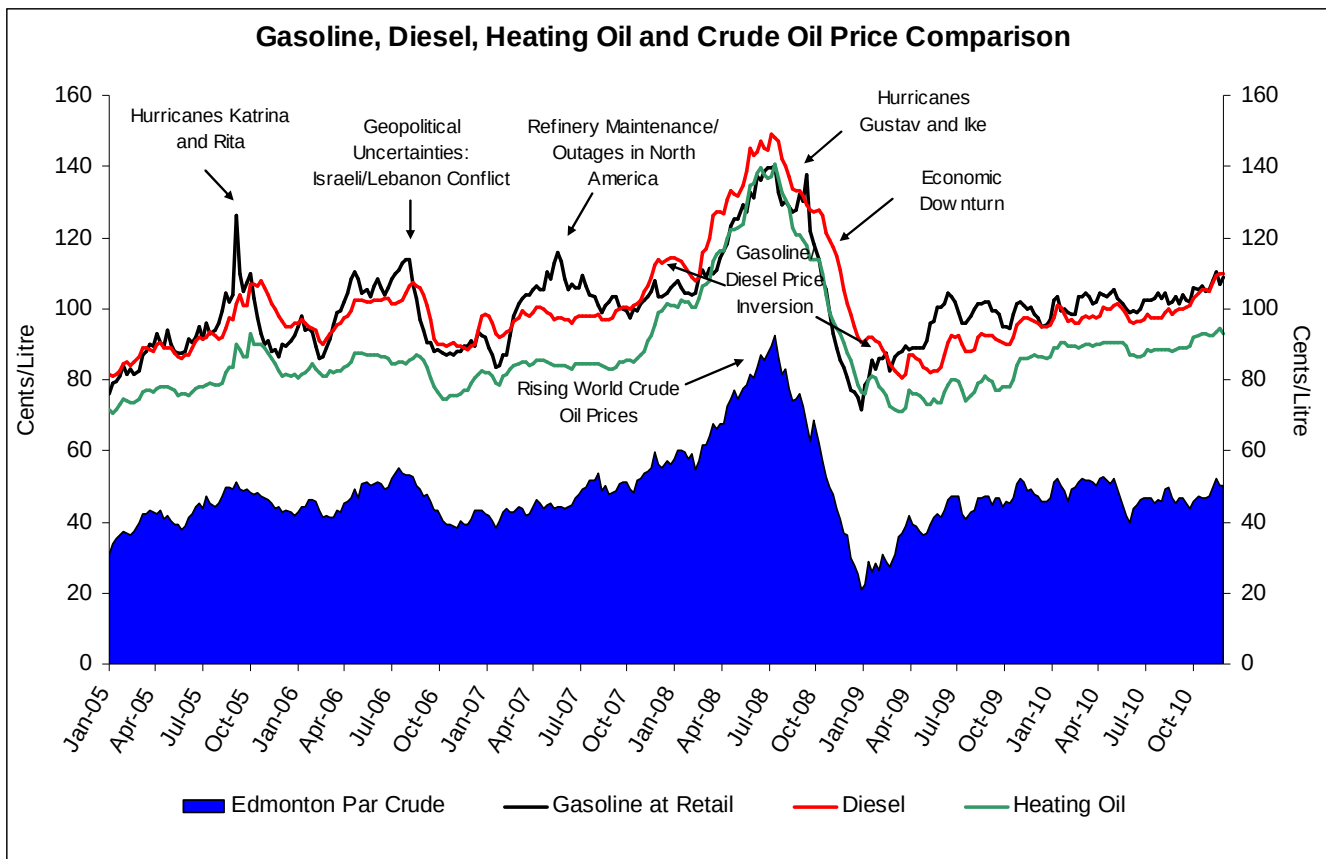
**These numbers indicate the movement of petroleum products leaving the province/region.

Source: Statistics Canada

Canada both imports and exports petroleum products. Although production has historically been substantially higher than consumption, rising domestic demand now means that imports are more often required in order to balance domestic markets.

Atlantic Canada

Canada exports significant volumes of gasoline, primarily to the US eastern seaboard, from refineries in Atlantic Canada. In fact, in 2008, 65% of the products manufactured in Atlantic Canada were exported, accounting for over 77% of Canada's total exports of refined petroleum products. Atlantic Canadian refiners have been very successful in marketing their ultra-low sulphur products into the US. In 2008, Irving Oil announced plans for a new petroleum refinery, the Eider Rock project, that could process up to 300,000 barrels of crude oil per day. However, in July 2009, Irving Oil and its partner BP announced that the proposed new refinery would be postponed.



In addition to being a large exporter of petroleum products to the US, Atlantic Canada also has good access to petroleum product imports. Domestic refiners must thus compete with supplies from the Northeastern US and Europe.

Quebec/Ontario Region

The Quebec and Ontario markets are becoming increasingly integrated with significant Quebec refined product being transported to Toronto via the Trans-Northern pipeline. Quebec also serves as a gateway to Ontario for imported products.

Western Canada

In Western Canada the supply and demand balance for petroleum products has become increasingly tight because much of Western Canada is landlocked, there is limited access to supplies from other regions. Refineries had been operating at near full capacity for several years. However, supply constraints from planned turnarounds and unplanned refinery maintenance and closures resulted in the region becoming a net importer of gasoline and distillates in 2007 and 2008 and of gasoline in 2009.

Petroleum Product Prices

Canadian gasoline prices in 2009 were less volatile than in 2008, averaging 95 cents a litre. This was 19 cents below 2008, when prices averaged \$1.14 per litre, due to strong gasoline demand and record high crude prices. These factors resulted in retail prices hitting a record high of \$1.40 in mid-July 2008. However, this was soon followed by a sharp downswing as crude prices dropped and by the end of 2008, gasoline prices had bottomed to 72 cents a litre.

Diesel fuel prices averaged \$1.25 per litre in 2008, an increase of 25 cents per litre compared to 2007. As with gasoline, diesel prices rose significantly to reach an all-time high of \$1.49 per litre in mid-July, and then dropped steadily until the end of the year. In 2009, after starting the year in a downswing, diesel prices averaged 90 cents per litre. Atypically, from September 2007 to February 2009, diesel prices had risen above gasoline prices due to strong world demand growth for diesel vis-à-vis other petroleum products. However, this situation was later reversed with the decline in economic activity and the resulting effect in the construction, agricultural and transportation sectors. Diesel prices

dropped and stayed below gasoline prices for the remainder of 2009.

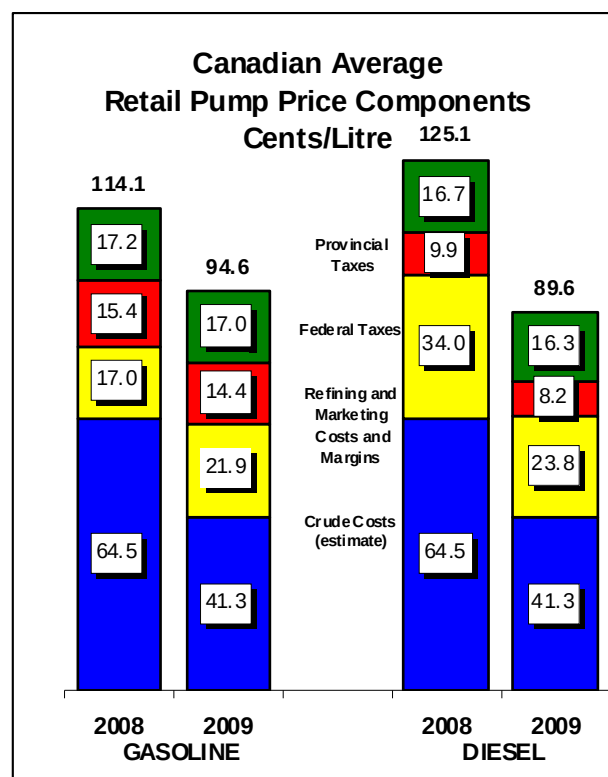
Current and historical prices for gasoline and diesel are available on NRCan's FuelFocus Web site at www.fuelfocus.nrcan.gc.ca.

Consumption Taxes on Petroleum Products

An important element of the gasoline and diesel retail pump prices is the tax component. Depending on the location, federal, provincial and, in some cases, municipal and carbon taxes apply on these products.

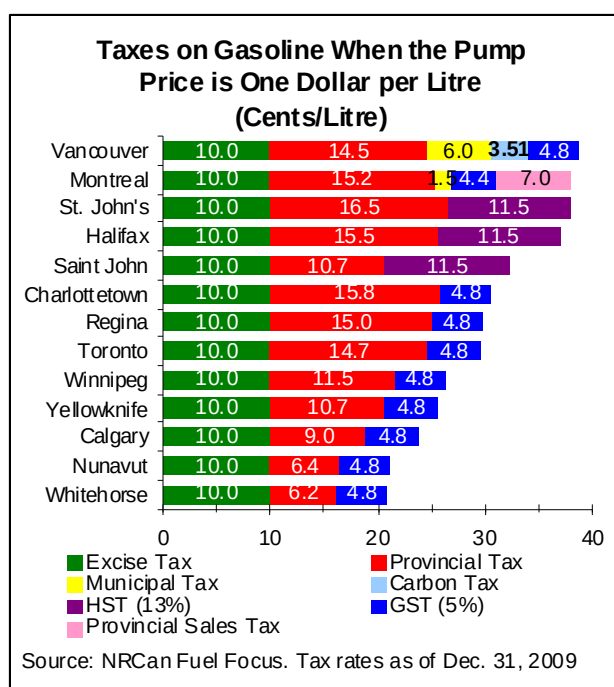
There were some significant changes in petroleum product consumption taxes in 2008 and 2009. Federal excise taxes on gasoline and diesel remained unchanged at 10 cents and 4 cents a litre, respectively. The other component of the federal tax, the Goods and Service Tax (GST) and, by extension the Harmonized Sales Tax (HST)¹⁰, was reduced on January 1, 2008, by 1% to 5% and 13%, respectively. (The federal portion of the HST is the same for all provinces.)

On July 1, 2008, British Columbia introduced a carbon tax applicable on all petroleum products used to produce energy and heat. B.C. is the first province to have a carbon tax, which is a consumer tax, payable at time of purchase. The



carbon tax rate was initially set on a carbon dioxide equivalent value of \$10 per tonne and will increase by increments of \$5 every July 1 until it reaches \$30 on July 1, 2012. On July 1, 2008, the carbon tax was 2.34 cents a litre for gasoline and 2.69 cents a litre on diesel and heating oil and on July 1, 2009, increased to 3.51 cents and 4.04 cents a litre, respectively.

The figure to the left provides an overview of the tax component breakdown on a litre of gasoline by centres across Canada based on December 1, 2009 tax rates. A table with all applicable federal, provincial and municipal taxes on petroleum products, including diesel and heating oil, is available in Appendix A.



¹⁰ The GST and the provincial sales tax are harmonized in Newfoundland/Labrador, Nova Scotia and New Brunswick.

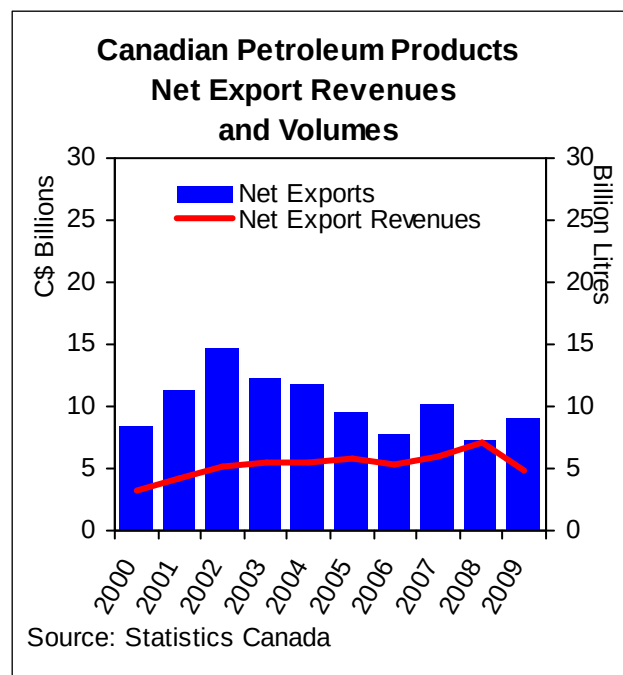
Petroleum Product Imports, Exports, and Revenues

In 2009, Canadian export revenues from finished products were \$12 billion, down 33% from 2008, a year when product prices were at record high levels. Import costs totalled about \$7 billion, down 33%, for net export revenues of roughly \$5 billion. In 2009, exports of finished products dropped by 3% to 24.9 billion litres while imports of finished products into Canada dropped 13% to 15.9 billion litres. In total, net exports of finished products in 2009 were 9.1 billion litres, up from the 7.3 billion litres in 2008.

Petroleum Products Exports and Imports			
	2008	2009	Change
Exports (Gross)			
Volume (billion litres)	25.6	24.9	-3%
Export Revenue (billion)	\$18.0	\$12.1	-33%
Imports (Gross)			
Volume (billion litres)	18.3	15.9	-13%
Import Expense (billion)	\$10.9	\$7.4	-33%
Net Exports			
Volume (billion litres)	7.3	9.1	+25%
Net Export Revenue (billion)	\$7.1	\$4.8	-32%

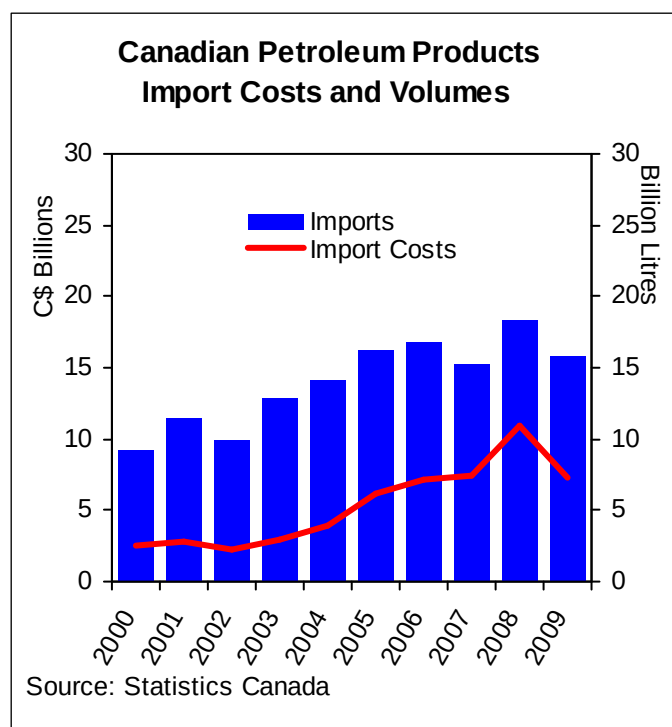
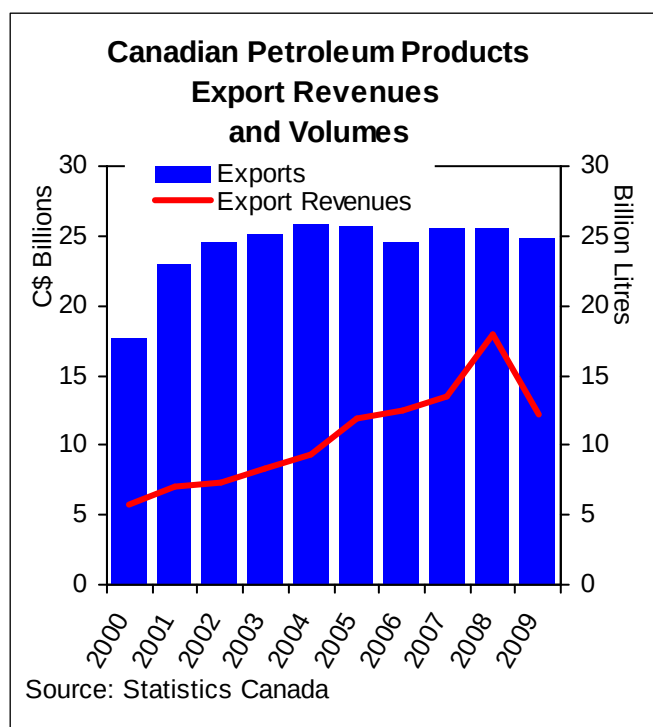
Source: Statistics Canada

While export revenues have been trending upwards in the past 10 years – with the exception of 2008 and 2009 which saw significant product price swings – exports volumes have typically been in the range of 23 to 26 billion litres per year since 2000. Most of these exports originated in eastern Canada where two refineries produce a significant volume of products destined for Northeastern US markets. However, during the same period, there has been increased reliance on product imports to satisfy demand in Quebec and Ontario. Refinery closures, short term disruptions, new product specifications and



increased demand are some of the contributors to this trend.

Net exports of refined petroleum products were 9.1 billion litres in 2009. However, as both imports and exports have increased over the last decade, net exports remain relatively unchanged when compared to 2000.

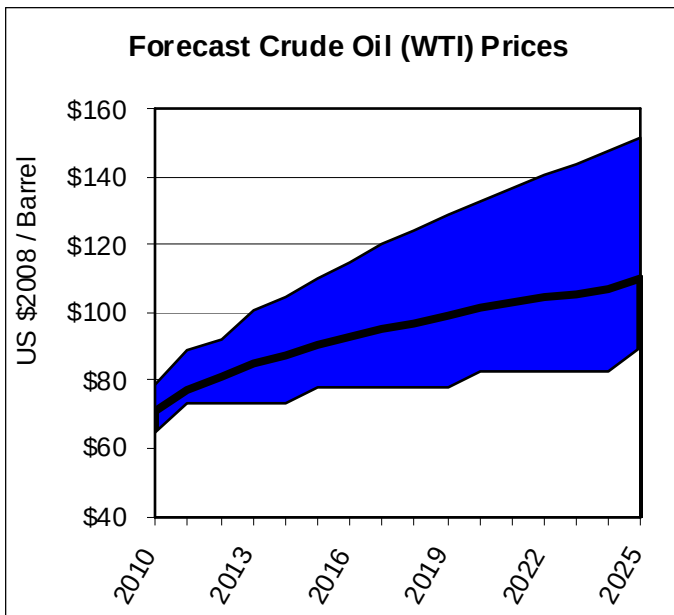


Outlook to 2030

Energy forecasts are useful to help inform policy development. NRCan's Petroleum Resources Branch does not generate its own forecasts; instead, PRB canvasses both publicly available and private industry forecasts, including Ziff Energy Group. However, within NRCan, the Energy Policy Branch does produce an oil and natural gas price outlook as part of its Energy Outlook. Plotted together, these forecasts provide a good sense of market expectations. The graphs depict the range of minimum and maximum forecasts, as well as the average of all forecasts, for crude oil and natural gas prices, production and demand.

Crude Oil Forecasts

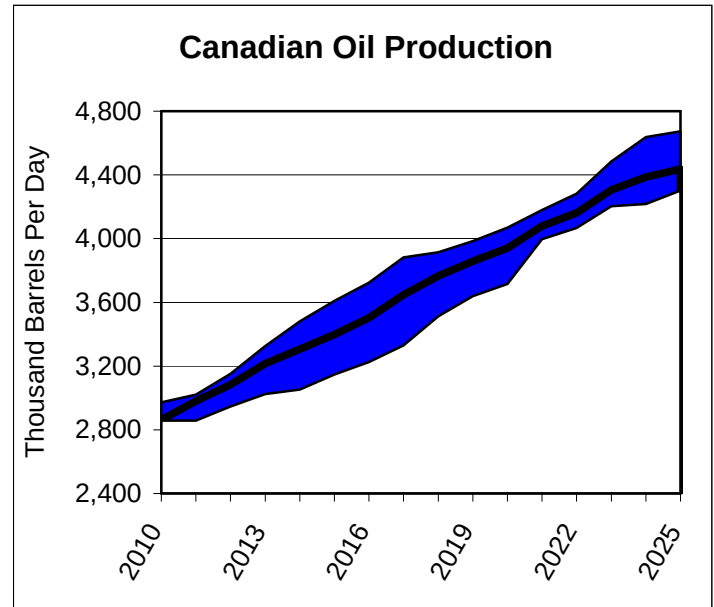
Crude oil prices are widely anticipated to increase over the coming decades. Noteworthy is the fact that crude oil forecasts normally take into account current market conditions and prices are subsequently extrapolated into the future. Given the difficulty of predicting all of the factors which can influence the price of oil, there is no clear consensus on future oil prices.



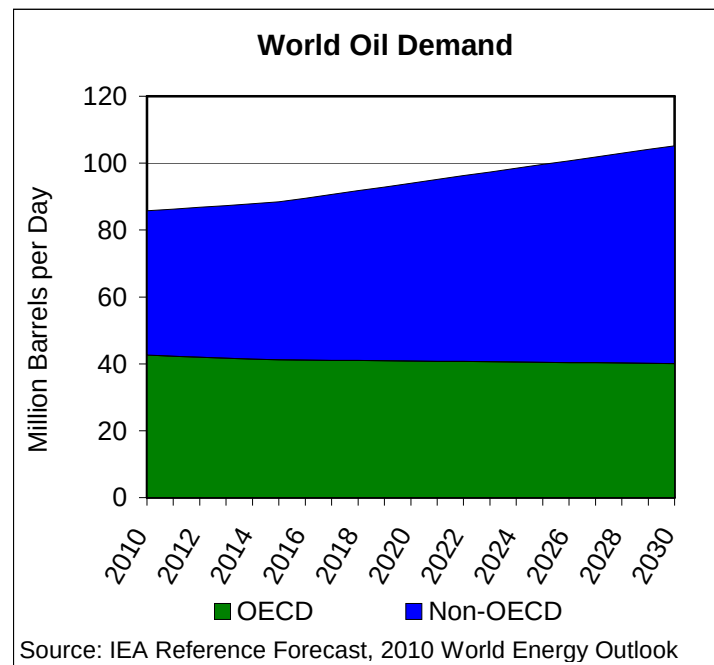
The range of long-term crude price forecasts is shown. These forecasts, the majority of which only go out as far as 2025, reflect a recent view as to the direction of oil prices.

The range of Canadian crude oil production forecasts shows considerable variability. All of

the forecasts anticipate that Canada's conventional crude oil production will decline over time, and oil sands production will progressively make up a larger share of production.



Overall, the forecasts point towards rising Canadian crude oil production in the coming years driven by the oil sands.



Source: IEA Reference Forecast, 2010 World Energy Outlook

Of note is the fact that Canada is the only OECD member country with rising crude oil production. The major source of variability in all of the forecasts is the extent to which oil sands production will come online over the coming decades.

Overall, the forecasters expect that Canadian oil sands production could more than double to around 3 mb/d by 2020. By 2025, total Canadian crude oil production could exceed 4.5 mb/d with most production coming from the oil sands.

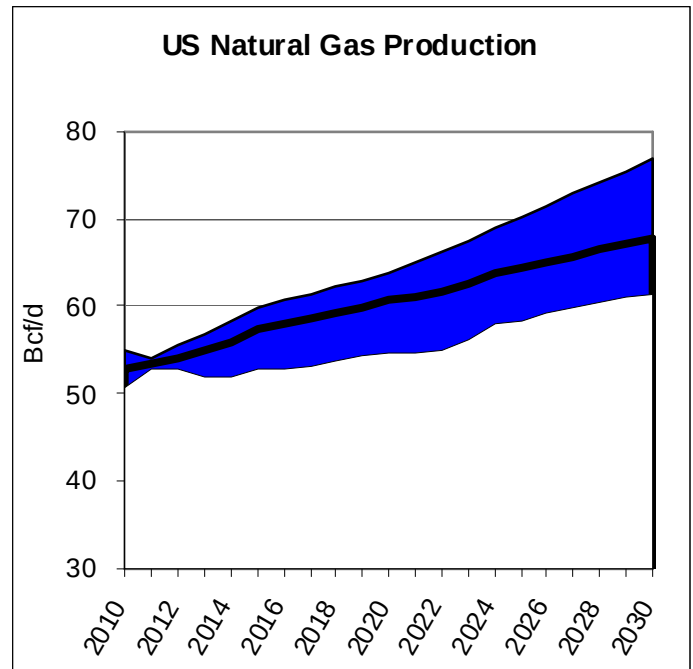
Canada has a large and growing net surplus of crude oil. The domestic market for oil sands production will grow with increased production. Rising surplus Canadian crude oil production will help meet the demands for oil in the US market, and could be exported to new markets in Asia.

Between 2009 and 2030, the reference forecast shows world oil demand growing by 1% per year, due entirely to demand from Non-OECD countries particularly from Asia. In fact, China and India alone are projected to account for close to two-thirds of the increase in demand.

Oil demand from Non-OECD countries, including those in North America, is expected to decline.

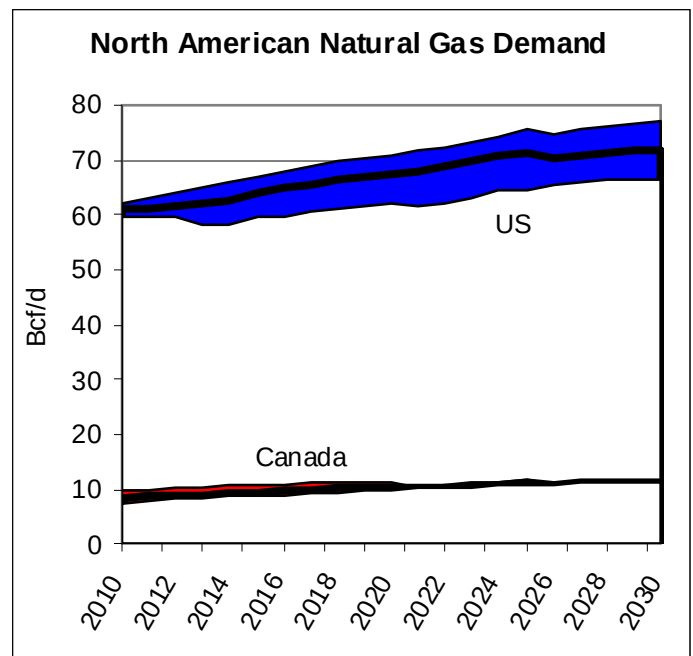
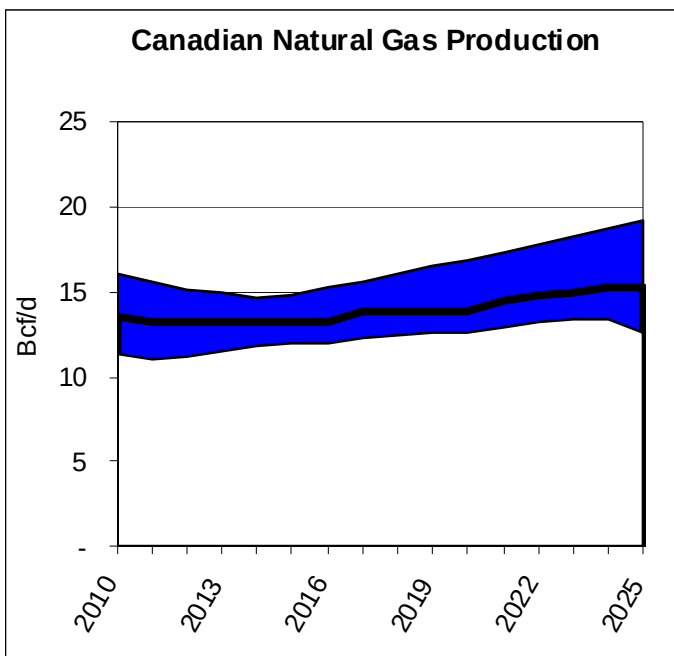
Natural Gas Forecasts

A survey of Canadian natural gas production forecasts, the majority of which only go out as far as 2025, shows considerable variability,



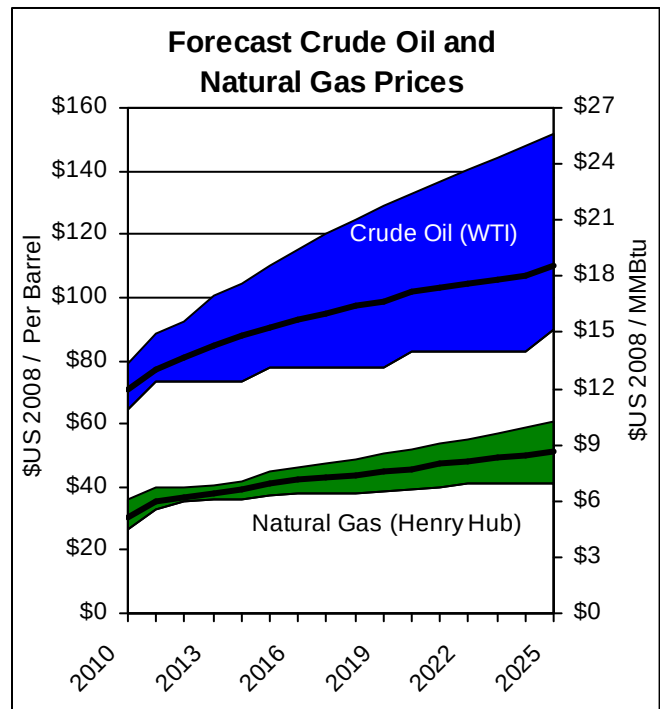
particularly in the long run. All forecasts point to declining production in the coming years. With the exception of the NEB's Low Price scenario, most forecasts anticipate Canadian production recovering over the long term. The major source of variability in all forecasts is the extent to which Canadian shale gas production will come online over the coming decades.

Production expectations are more bullish for the US where all surveyed forecasts point to considerably higher production over the long term. Expectations concerning a growing supply reflect increased optimism surrounding shale gas development in the US.



Demand for natural gas is expected to increase over the long term. This reflects a continuing trend that is decades old. Natural gas demand typically increases by about 1 percent per year.

Despite optimism surrounding unconventional gas production, natural gas prices are anticipated to increase over the coming decades. Noteworthy is that prices are also expected to continue trading at a significant discount to oil prices (on an energy content basis). The decoupling of crude oil and natural gas prices that has taken place recently, largely on account of surging shale gas production, is expected to stay for the long term.



Appendix A – Taxes on Petroleum Products

Taxes on Petroleum Products – December 31, 2009 (Cents/Litre)

	Gasoline	Diesel	Propane (motor vehicle)	Furnace Oil/ Natural Gas (for heating)
Excise Tax	10.0	4.0		
Goods and Services Tax	5%	5%	5%	5%
OR : Harmonized Sales Taxes (which applies in NF, NS, NB) ⁽¹⁾	13%	13%	13%	13%
Newfoundland and Labrador	16.5	16.5	7.0	
Prince Edward Island ⁽²⁾	15.8	19.6		
Nova Scotia	15.5	15.4	7.0	⁽³⁾
New Brunswick	10.7	16.9	6.7	
Québec ⁽⁴⁾	15.2	16.2		
Quebec Sales Tax	7.5%	7.5%	7.5%	7.5%
Ontario	14.7	14.3	4.3	
Manitoba	11.5	11.5	3.0	
Saskatchewan	15.0	15.0	9.0	
Alberta	9.0	9.0	6.5	
British Columbia ⁽⁵⁾	14.5	15.0	2.7	
Additional Carbon Tax	3.51	4.04	2.31	4.04/2.85
Yukon	6.2	7.2		
Northwest Territories ⁽⁶⁾	10.7/6.4	9.1		
Nunavut ⁽⁶⁾	10.7/6.4	9.1		
Additional Transportation Taxes in Specific Markets (in addition to above-mentioned taxes)				
Montreal ⁽⁴⁾	1.5			
Vancouver ⁽⁵⁾	6.0	6.0		
Victoria ⁽⁵⁾	2.5	2.5		

Notes:

1. In Newfoundland and Labrador, New Brunswick and Nova Scotia, the Goods and Services Tax (GST) and the provincial retail sales taxes are replaced by a single, harmonized value-added tax, the Harmonized Sales Tax (HST), applicable on all petroleum products.
2. Since April 2005, gasoline and diesel taxes in Prince Edward Island are revised on the first day of the month.
3. Nova Scotia has a point of sale tax rebate of the provincial portion of the GST on furnace oil.
4. In Quebec, gasoline, diesel and propane taxes are reduced by varying amounts in certain remote areas and within 20 kilometres of the provincial and US borders. The Quebec provincial retail sales tax (QST) applies to all petroleum products. In Montreal and surrounding municipalities there is an additional urban tax of 1.5 cents per litre on gasoline.
5. On July 1, 2008, British Columbia (BC) introduced a carbon tax on fuels used to produce energy or heat. In the Greater Vancouver and Victoria areas, there are additional transportation taxes of 6 and 2.5 cents per litre, respectively, on gasoline and diesel. For more information on all fuel taxes in BC, visit the Ministry of Finance Web site:
http://www.sbr.gov.bc.ca/business/Consumer_Taxes/consumer_taxes.htm.
6. In the Northwest Territories and Nunavut gasoline is taxed at 6.4 cents per litre in communities not served by a highway system.

Acronyms

kb/d = Thousand Barrels Per Day

mb/d = Million Barrels Per Day

bbl = Billion Barrels

$10^3\text{m}^3/\text{d}$ = Thousand Cubic Metres Per Day

$10^6\text{m}^3/\text{d}$ = Million Cubic Metres Per Day

MMcf/d = Million Cubic Feet Per Day

Bcf = Billion Cubic Feet

Tcf = Trillion Cubic Feet

EIA = Energy Information Administration

IEA = International Energy Agency

NEB = National Energy Board

NRCan = Natural Resources Canada

OECD = Organization for Economic Cooperation and Development

OPEC = Organization of Petroleum Exporting Countries

Major Data Sources

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Canada's Emissions Trends 2012

Environment Canada

August 2012

Canada

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Executive Summary

Overview

When Canada signed the Copenhagen Accord in December 2009, it committed to reduce its greenhouse gas (GHG) emissions to 17% below 2005 levels by 2020, establishing a target of 607 Megatonnes (Mt). This mirrors the reduction target set by the United States.

According to the International Energy Agency, Canada's CO₂ emissions from fuel combustion in 2009 accounted for approximately 2% of global emissions. Canada's share of total global emissions, like that of other developed countries, is expected to continue to decline in the face of rapid emissions growth from developing countries.

The Government of Canada's initial focus in tackling GHG emissions has been directed at the largest source of Canadian emissions through regulation of the transportation sector, as well as actions to reduce emissions from electricity generation. The Government is now turning its focus to work with partners in other key economic sectors, in particular, working with our partners in the oil and gas sector to make further progress on meeting our target.

The future path of greenhouse gas emissions in Canada will depend on a number of factors including: economic activity, population, development of energy markets and their influence on prices, technological change, consumer behaviour, and government actions.

Last year, Canada's GHG emissions were projected to be 785 Mt in 2020. Since that time, there have been several key developments and GHG emissions are now projected to be 65 Mt lower at 720 Mt in 2020. This is despite the fact that Gross Domestic Product (GDP) is projected to be slightly higher in 2020 in this year's projection. The decline in projected emissions, when compared to last year, is influenced by four main factors:

- Emissions are increasingly becoming decoupled from economic growth. Changes in behaviour by consumers and businesses, in part due to federal, provincial and territorial actions, are leading to a decline in emissions intensity.
- Projected sectoral shifts in the economy are also contributing to this improvement in emissions intensity. Compared to last year's report, projected growth for the emissions-intensive sectors is now lower, while it is now higher for the less emissions-intensive sectors. This reduces projected emissions in 2020, even though total GDP is projected to be slightly higher.
- For the first time, the contribution of the land use, land-use change and forestry (LULUCF) sector to achieving Canada's target is included in our projections.

- This year's projections also have a new, lower starting point as the most recent data show emissions were significantly lower in 2010 than previously estimated. Last year, emissions were estimated to be 710 Mt and since that time, preliminary data collected by Statistics Canada and assessed for the National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada (NIR) put Canada's actual emissions in 2010 at 692 Mt.

Canada's Greenhouse Gas Inventory shows a decoupling of GHG emissions from economic growth

Canada's total greenhouse gas emissions in 2010 were 692 Mt, essentially unchanged from 2009 levels (a 0.25% increase). This means that between 2009 and 2010, Canada's emissions remained steady despite economic growth of 3.2%.

Over the last two decades, technological and structural changes, along with increases in efficiency, have acted to create this decoupling of emissions and economic growth. The Canadian economy has experienced a substantial decline in energy intensity as industrial processes have become more efficient and lower-emissions and service-based industries have grown. As well, emissions from energy generation have declined, primarily due to changes to the generation mix and closure of coal-fired generating units. As a result, economic activity and the level of greenhouse gas emissions are becoming increasingly independent. Between 2005 and 2010, the economy grew by 6.3% whereas Canadian greenhouse gas emissions decreased by 6.5%.

Per capita emissions in 2010 fell to 20.3 tonnes of carbon dioxide equivalent per person, their lowest level since tracking began in 1990. In comparison to the 2005 level (22.9 t CO₂ eq/capita), per capita emissions in 2010 are 2.6 tonnes of carbon dioxide equivalent lower. Canada is making steady progress towards its commitment to reduce GHG emissions. Of note, since 2005, annual greenhouse gas emissions have dropped by 48 megatonnes and emissions have declined in almost all sectors, including oil and gas and electricity generation.

Emissions intensity continues to improve through 2020 with help from federal, provincial, and territorial actions

In this year's report, Gross Domestic Product (GDP) is projected to be slightly higher in 2020 than in the previous report (by 0.8%), while GHG emissions are lower (by 5.3%). The projected decline in GHG emissions is thus associated with a reduction in intensity, implying greater de-coupling between GDP and GHGs. The improvements in emission intensity are in part due to: i) increased contribution of the services sector, which typically emits less emissions per dollar of GDP; and ii) actual emissions in 2010 were lower than projected, while actual GDP was higher. The decline in emissions

intensity was also due to the fact that consumers and businesses are making more progress in reducing emissions. Government programs are contributing to this by helping to accelerate the adoption of energy efficient technologies and cleaner fuels.

Canada is moving forward to regulate GHGs on a sector-by-sector basis, aligning with the U.S where appropriate. The Government of Canada has started with the transportation and electricity sectors – two of the largest sources of Canadian emissions – and plans to move forward with regulations in partnership with other key economic sectors, including oil and gas. Last year's report included emissions regulations for light-duty vehicles for the model years 2011-2016 as well as an electricity performance standard to phase-out coal-fired electricity, Alberta's Specified Gas Emitters Regulation, British Columbia's carbon tax and Quebec's carbon levy. Provincial policies such as Ontario's phase-out of coal-fired electricity also made important contributions. Projected emissions levels in the 2012 version of the report have further declined, in part through the inclusion of further federal actions on additional emissions regulations for light-duty vehicles for the 2017-2025 period as well as heavy duty vehicle regulations. Recent provincial actions (e.g., Quebec's cap-and-trade, Nova Scotia's emissions cap for electric utilities, increased stringency of building energy codes, equipment standards and requirements for capturing methane from landfill gas) are also included. Total emissions in 2020 are projected to decrease to 720 Mt.

The future trajectory of Canadian GHG emissions can, and will, be influenced by further government actions, technological change, economic conditions, and developments in energy markets. Recognising this, Environment Canada has developed scenarios for projected emissions based on different assumptions regarding future economic and energy market developments.

For the first time, there is recognition of the contribution of the Land Use, Land-Use-Change and Forestry sector

The Land Use, Land-Use-Change and Forestry sector (LULUCF) has been internationally recognised as an important consideration in global accounting frameworks for emissions reductions. Improvements in greenhouse gas related activities within Canada's LULUCF sector can make an important contribution towards reducing national emissions levels, given Canada's large supply of forest and cropland.

This 2012 Emissions Trends Report represents a key milestone for Canada in moving towards the inclusion of the LULUCF sector in accounting of GHG emissions. New projections allow the inclusion of the LULUCF sector in emission projections for the first time. Current estimates suggest a net contribution of 25 Mt of GHG emissions towards the 2020 target. While these estimates are preliminary in nature and will change as a result of ongoing efforts to improve data and methodologies as well as the consideration of alternative accounting approaches, they provide a solid first step toward recognizing the important contribution from LULUCF.

This important step will encourage advancement in policies and measures to make further progress towards Canada's GHG reduction goals.

The report projects that Canada is one half of the way toward meeting its Copenhagen Commitment

Overall, this report demonstrates that Canada is making significant progress towards meeting its 2020 target for GHG emissions. Beyond federal initiatives, provincial and territorial governments are contributing with significant action of their own under their respective jurisdictional targets. Taken together, the measures of the federal and provincial governments, combined with the efforts of consumers and businesses, are projected to have a significant impact on emissions over the coming years.

Table ES 1 - Canadian GHG Emissions and Government Measures (Mt CO₂e)

	2005	2010	2015	2020
Emissions – Assuming No Government Measures (2011)	740	718	784	850
Emissions – with Existing Government measures (2012 update)*	740	692	700	720

* Includes the contribution of LULUCF in 2015 and 2020.

Last year, Canada's GHG emissions were projected to be 850 Mt in 2020 under a scenario assuming no government measures to reduce emissions. Taking into account existing measures of federal, provincial and territorial governments, it was projected that emissions would be 785 Mt in 2020. This reduction of 65 Mt represented one quarter of the reductions needed to meet Canada's target of 607 Mt. This year, GHG emissions are now projected to be 720 Mt in 2020, as a result of all the developments outlined in this report. The gap between the initial projected business-as-usual GHG emissions in 2020 (850 Mt) and the 607 Mt target now has been closed by 130 Mt – one half of the way to meeting Canada's target. Upcoming federal policies, in particular oil and gas regulations, along with further provincial measures, will further contribute to the additional 113 Mt required for Canada to meet its commitments under the Copenhagen Accord.

Figure ES 1 - Scenarios of Canadian Emissions to 2020 (MtCO₂e)

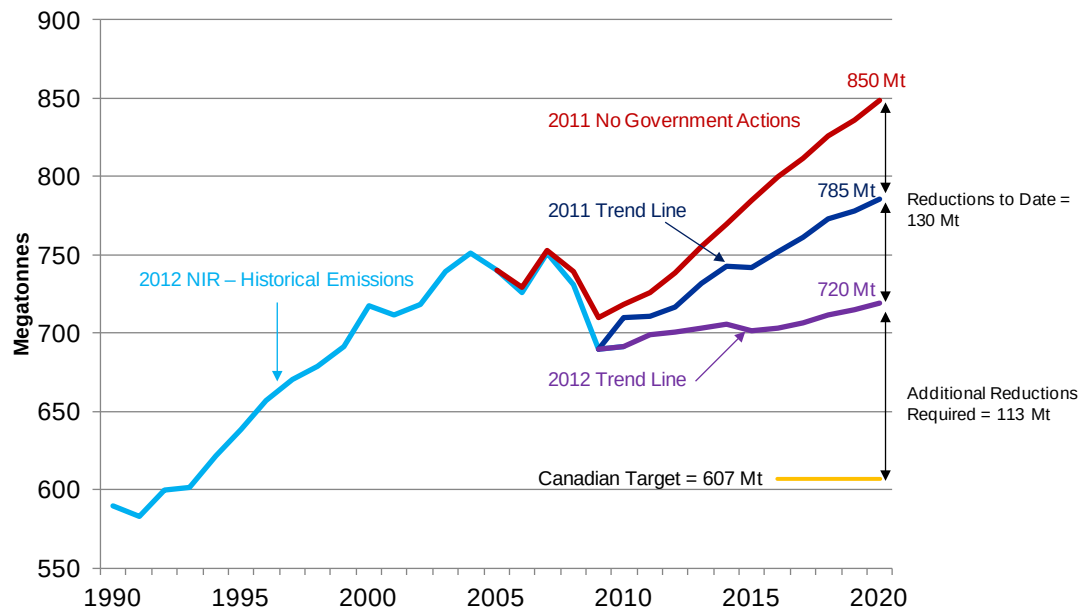


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Preface

Consistent with its goal of becoming a “World Class Regulator”, and ensuring greater transparency, Environment Canada has committed to publish emissions projections annually. This is the second annual report, building on last year’s publication, *Canada’s Emissions Trends 2011*.

The analysis presented in this report incorporates the most up-to-date statistics on GHG emissions and energy available at the time that the technical modeling was completed¹, and is based on scenarios of emissions projections using a detailed, proven Energy, Emissions and Economy Model for Canada.

Last year, projected emissions were 710 Mt in 2010. Since that time, data collected by Statistics Canada for 2010 has been assessed for the National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada (NIR) in accordance with standards set by the Intergovernmental Panel on Climate Change – a United Nations body. Estimates published in the 2012 NIR show that Canada’s emissions in 2010 were actually 2.6% lower at 692 Mt. Subsequently, emissions projections in this paper have been revised down compared to the 2011 Report to reflect these changes as well as factors such as slower than expected economic growth for certain emissions-intensive subsectors.

Provincial and federal government departments were consulted during the model’s development and were invited to provide their input and suggestions for improvement. Environment Canada also consulted industry experts to improve the model and core technical assumptions.

The majority of data and advice received from sector experts and authorities for the modelled emissions scenarios have been subjected to rigorous consultations. For example, the National Energy Board has extensive consultation processes in place to ensure their assumptions of energy demand and supply growth are robust; the input they provided to Environment Canada reflects those consultations.

In addition, the methodology used to create the projections underwent a peer review by a panel of experts in 2010/2011. In the peer review, the experts assessed the modeling methodology on its reasonableness and robustness, reviewed the sources for the key macroeconomic and energy-related assumptions, and made suggestions on how to continue improving the methodology in future rounds. While we are working with a highly detailed and sophisticated model, as with all projections, the estimates in this paper should be seen as representative of possible outcomes that will, in the end, depend on economic, social and other factors, including future government policy.

Questions and requests for further information on the analysis underlying this report should be directed to: AMD_EAD@ec.gc.ca

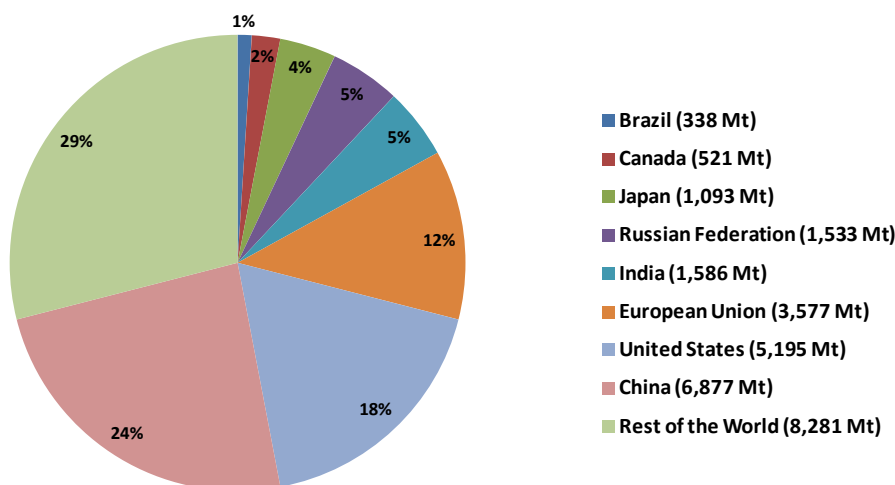
¹ Emissions inventory data used for this analysis is derived from National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada.

Canada's GHG Emissions in a Global Context

It is important to put Canada's situation into context by comparing to other countries. According to the International Energy Agency, Canada's CO₂ emissions from fuel combustion in 2009 accounted for approximately 2% of global emissions².

Global emissions of CO₂ have increased by 38% between 1990 and 2009. Over the same period, Canadian CO₂ emissions have increased by less than 19%. Canada's share of total global emissions, like that of other developed countries, will continue to decline in the face of rapid emissions growth from developing countries, particularly China and India. By 2005, China had overtaken the U.S. as the world's largest overall greenhouse gas emitter, and by 2020 China's greenhouse gas emissions are expected to account for 27% of global emissions, up from about 20% in 2005.

Figure 1 - Distribution of world carbon dioxide emissions from fuel combustion, 2009



Source: www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=54C061B5-1

The Copenhagen Accord is a critical instrument for addressing such dramatic escalation in global emissions because it is signed by 140 nations, representing 85% of the world's GHG emissions. For example, the Accord was signed by China, the U.S., Brazil and India, which together account for over 40% of global emissions. In contrast,

² As the most recent total greenhouse gas emissions by countries are for 2005, CO₂ emissions are being used as they are more recent.

none of these major emitters had commitments under the Kyoto Protocol, an agreement that involved commitments of only 40 nations representing 27% of global emissions.

When Canada signed the Copenhagen Accord in December 2009, it committed to reducing its GHG emissions to 17% below 2005 levels by 2020. This mirrors the reduction target set by the United States, which is also following a sector-by-sector approach. Canada is moving in alignment with the U.S. given the importance of our economic relationship. Every day, \$1.8 billion in goods and services crosses the border, and fully 85% of Canada's trade is with the United States. Comparatively, Canada has relatively less trade with other large partners. This makes the United States Canada's primary link into global value chains – which is the transformation process of a product from raw materials to finished good, or the process of developing tradable services. The GHG regulations for light duty and heavy duty vehicles are examples of an aligned approach. With aligned regulations, light duty vehicle and heavy duty vehicle manufacturers face the same rules in each country, providing greater investment certainty and a level playing field. Furthermore, all Canadians benefit from the efficiency of having a single set of regulations in the integrated North American auto sector.

GHG Emissions by Sector

Emissions by Activity and Economic Sector

There are several methods to categorise the sources of greenhouse gas emissions that arise across Canada. In Canada's National Inventory Report (NIR)³, as specified by the United Nations Framework Convention on Climate Change definitions, greenhouse gas emissions are primarily categorized by emitting activity: e.g., emissions from energy use, fugitive emissions, transportation emissions, and emissions from industrial processes. However, for the purposes of analyzing trends and policies, it is useful to allocate emissions to the economic sector from which they originate. As such, both this report and the 2012 NIR present emissions by economic activity.

Historical Emissions

Historical emissions estimates within this report are taken from the *NIR* which is submitted to and reviewed by the United Nations Framework Convention on Climate Change (UNFCCC). Every year the estimates are updated to reflect the availability of data as well as improvements and refinements to data sources and methodological techniques. For this reason, the historical emissions reported here will differ from those reported in *Canada's Emissions Trends 2011*.

From 1990 to 2005, total emissions grew from 589 Mt to 740 Mt. The majority of this increase occurred in the transportation sector, the oil and gas sector and the electricity sector. In the transportation sector, changes in subsectors including light-duty and heavy-duty vehicles caused an increase in emissions of 42 Mt over this period. Expansion and adoption of new extraction technologies resulted in an increase in emissions of 60 Mt in the oil and gas sector. The electricity sector accounted for a further 29 Mt of the increase in total emissions.

Greenhouse gas emissions have decreased in almost every sector of Canada between 2005 and 2010. This is a result of factors such as the global economic downturn, changes to energy efficiency technology, changes in energy prices, and a decrease in the energy intensity of the economy. Moreover, federal and provincial government actions to reduce emissions had a significant impact on emissions over this time period.

Table 1 shows historical emission levels for selected years up to 2010 (the last available year of historical emissions numbers under the NIR for 2012) for each of the major economic sectors generating emissions.

³ Canada submits an annual National Inventory Report on Greenhouse Gases Sources and Sinks to the United Nations Framework Convention on Climate Change per the reporting methodology requirements of the International Panel on Climate Change.

Table 1 - GHG emissions by economic sector (Mt CO₂e)

Mt CO₂ equivalent	1990	2000	2005	2006	2007	2008	2009	2010
Oil and Gas	100	150	160	161	165	160	161	154
Electricity	92	128	121	115	124	112	96	99
Transportation	128	155	170	169	172	172	162	166
Emissions Intensive & Trade Exposed Industries	96	88	90	89	90	87	74	75
Buildings	70	81	85	80	85	85	82	79
Agriculture	54	65	67	66	68	68	67	69
Waste and Others	49	50	48	46	48	47	47	50
NATIONAL GHG TOTAL	589	718	740⁴	726	751	731	690	692

Transportation

Emissions from transportation (including passenger, freight, and off-road emissions) are the largest contributor to Canada's greenhouse gas emissions, representing 24% of overall greenhouse gases in 2010.

Between 1990 and 2005, emissions in the transportation sector increased 33% from 128 Mt in 1990 to 170 Mt in 2005. This was largely driven by a strong period of economic growth as well as a shift from cars to light-duty trucks.

Since 2005, transportation emissions have decreased 4 Mt. Light-duty vehicles have become increasingly more fuel efficient. For example, between 2005 and 2010, the sales-weighted on-road fuel economy for new cars has improved from 8.5 litres per 100 km to 6.8 litres per 100 km, while the sales-weighted on-road fuel economy for new light trucks has improved from 12.7 litres per 100 km to 8.5 litres per 100 km. Offsetting factors include an increase in number of vehicles on the road and kilometres driven.

⁴ Canada's target of 607 Mt is based on the 731 Mt for 2005 that was included in the 2011 NIR. Using 2012 data (740 Mt), and the same 17% reduction, would have increased the target to 614 Mt.

Electricity

Historically over the 1990 to 2005 period, emissions from the electricity sector increased in parallel with rising demand for electricity both domestically and to satisfy export demand from the United States. Additionally, fossil fuel power generation became more prominent in the overall generating portfolio between.

Electricity-related emissions (including heat generation) have generally declined since 2005 due to factors such as a return to service of a number of nuclear units and fuel switching to natural gas, as well as a decline in coal-fired electricity generation in Ontario. These factors coupled with the economic downturn have seen emissions from the electricity sector decrease by 22 Mt between 2005 and 2010.

Oil and Gas

Conventional oil and gas production and petroleum refining emissions are related primarily to the production, transmission, processing, refining and distribution of all oil and gas products. In 2010, the Oil and Gas economic sector produced the second largest share of greenhouse gas emissions in Canada (22%).

Emissions from this sector increased by 60 Mt over the 1990 to 2005 time period as the sector expanded and adopted new extraction processes. However, GHG emissions from the Oil and Gas sector have fallen by 6 Mt between 2005 and 2010. This more recent decrease in the emissions from the oil and gas sector is the result of a number of factors including a lower global demand for petroleum products during the economic downturn, as well as the gradual exhaustion of conventional natural gas and oil resources in Canada.

Emissions-Intensive and Trade-Exposed Industries (EITE)

Emissions from the Emissions-Intensive Trade-Exposed Industry sector⁵ were responsible for 16% of total Canadian emissions in 1990 falling to 12% in 2005. In more recent years, emissions have fallen further as a result of the economic downturn and the continued evolution of Canadian production towards other sectors and services, representing an additional decrease of 15 Mt between 2005 and 2010 (11% of total emissions).

The decline in emissions was also due to the contribution of several factors such as the installation of nitrous oxide abatement technology in Canada's only adipic acid manufacturing plant and the improved emission control technologies for perfluorocarbons within the aluminum industry. Energy efficiency measures, replacement of raw materials with recycled materials, and use of unconventional fuels such as biomass and waste in the production processes, were also responsible for the reductions.

⁵ The Emissions-Intensive Trade-Exposed Industry sector represents emissions from mining activities, smelting and refining, and the production and processing of industrial goods such as chemicals, fertilizers, paper or cement.

Buildings

Emissions in Canada's service industry and residential buildings increased by 15 Mt overall between 1990 and 2005. However, more recently, between 2005 and 2010, emissions decreased by 6 Mt. This was driven by a 5 Mt decrease in commercial buildings, mainly due to improved energy standards and the adoption of higher-efficiency furnaces and other improved appliances.

Agriculture

Canada's agricultural emissions consist mainly of methane and nitrous oxide from animal and crop production systems. Emissions have remained relatively stable over the 2005 to 2010 time period increasing by only 2 Mt or 3%, following an increase of 13 Mt from 1990 to 2005. Increasing emissions from on-farm fuel use and crop production have been partially offset by decreasing emissions from animal production since 2005.

Waste and Others

Emissions from the Waste and Others sector have remained relatively stable over the period. GHG emissions from landfills increased only slightly over the time period, as provincial government measures aimed at capturing landfill gas from solid waste helped to slow growth. In contrast, emissions from coal production have nearly doubled over the 2005 to 2010 time period increasing by nearly 3 Mt.

Emissions Trends

Emissions Scenarios and Key Drivers

Greenhouse gas emissions in Canada are driven by a number of economic drivers (e.g., energy demand and supply mix, economic growth, among others). Looking ahead, projections of future emissions are greatly influenced by the underlying assumptions about the expected development of these economic drivers over time⁶. Changing assumptions about any of these factors will alter the future path of emissions.

The approach adopted for development of the emissions scenarios presented here relies on a baseline set of assumptions. In this respect, the economic projections are calibrated to those used by Finance Canada in Budget 2012. The longer-term projections incorporate productivity growth projections and Statistics Canada's population growth projections. Similarly, forecasts of major energy supply projects from the National Energy Board were incorporated for key variables and assumptions in the model (e.g., oil sands production, large hydro capacity expansions, nuclear refurbishment and additions). Supply forecasts are based on consultation with industry experts and reflect the Government's most recent views regarding the evolution of Canada's energy supply sector. The projections also incorporate data from the National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada (NIR), Natural Resources Canada, and the U.S. Energy Information Administration. For a more detailed summary of key economic data and assumptions see Annex 1.

It is impossible to predict Canada's greenhouse gas emissions with certainty, given the importance of the economic drivers and the intrinsic uncertainty related to the evolution of these drivers (e.g. GDP, energy prices) in the future. Government policy also has a significant impact on emissions, (including expected future policies) along with changes in behaviour as individuals place more importance on environmentally-friendly products and businesses adopt more environmentally-friendly processes. While the modeling explicitly recognizes technological progress (e.g., known advanced energy efficient technologies will become more cost-effective over time), it is virtually impossible to predict what new technologies will be developed and commercialized in the future. In this respect, future emissions will be shaped by existing government measures, as well as future measures that will be implemented as part of Canada's plan to reduce emissions to the target established in the Copenhagen Accord.

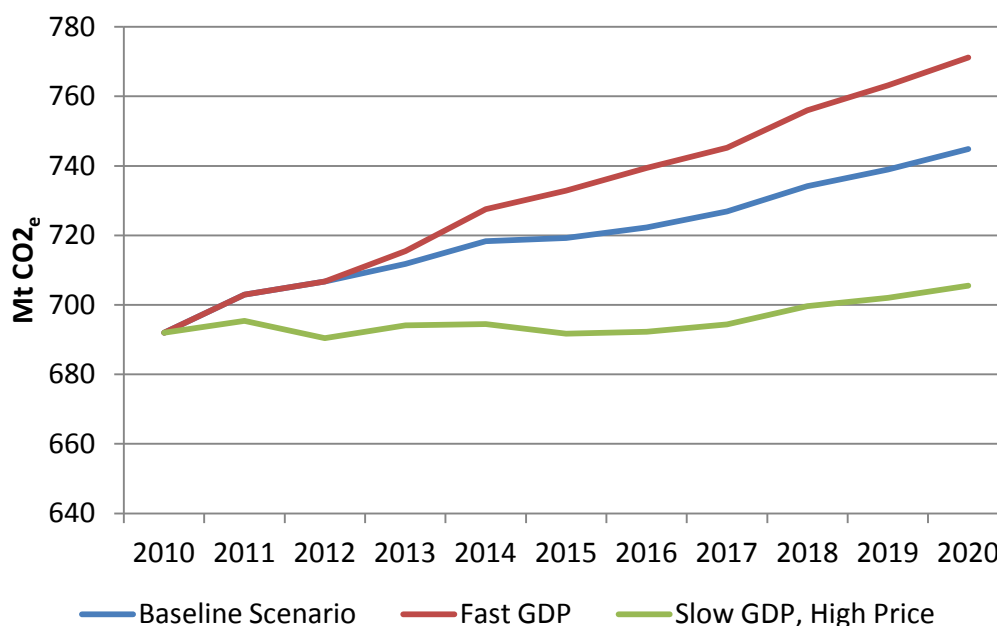
Taking into account the economic drivers described above, with no major technology changes and factoring in current government measures and land use, land-use change and forestry (LULUCF), results in a baseline scenario whereby emissions reach 720 Mt by 2020 (or 20Mt below 2005 levels).

⁶ For detailed information about individual key drivers, assumptions and key response dynamics, see Annex 1.

Given the uncertainty regarding the economic drivers, this scenario should be seen as one estimate within a set of possible emissions outcomes in 2020, depending on economic developments and underlying assumptions. To get a sense of the sensitivity of emissions to economic developments, emissions were calculated under a series of alternative assumptions involving relatively minor variations in assumed economic growth rates for Canada and world oil prices⁷.

For example, under a scenario of high GDP growth, reference world oil prices and no further government action, Canadian emissions, before accounting for contributions from LULUCF, could reach almost 771 Mt by 2020. Alternatively, with low GDP growth and high world oil, 2020 emissions, before accounting for contributions from LULUCF, could be as low as 705 Mt. Figure 1 illustrates these alternative emissions pathways. For a more detailed explanation of this sensitivity analysis, see Annex 2.

Figure 2 - Projected GHG emissions under alternative economic assumptions (excluding LULUCF)



These sensitivities illustrate that Canada's emissions projections should not be interpreted as a precise prediction or forecast of our emissions since, as outlined above, actual emissions will be determined by a range of as yet unknown developments in key drivers. Rather, the projections should be viewed as one plausible outcome for future emissions that provides a reference point for evaluating

⁷ Since sensitivity analyses have been performed around variables that affect energy and industrial production and consumption, LULUCF emissions are not included in these estimates. The inclusion of LULUCF contributions will reduce overall emissions levels.

the impact of economic and technological developments, as well as assessing the impact of existing and future government measures.

It is important to note that the projection of emissions in this report is based on existing government measures as of the spring of 2012 only, and does not reflect the impact of further federal measures that are under development as part of the government's plan to reduce GHG emissions to 607 Mt by 2020, nor new provincial measures that could be undertaken in the future. The impact of government measures on emissions is described in more detail in a later section.

Table 2 - Sensitivity of emissions to changes in GDP and world oil price (excluding LULUCF)

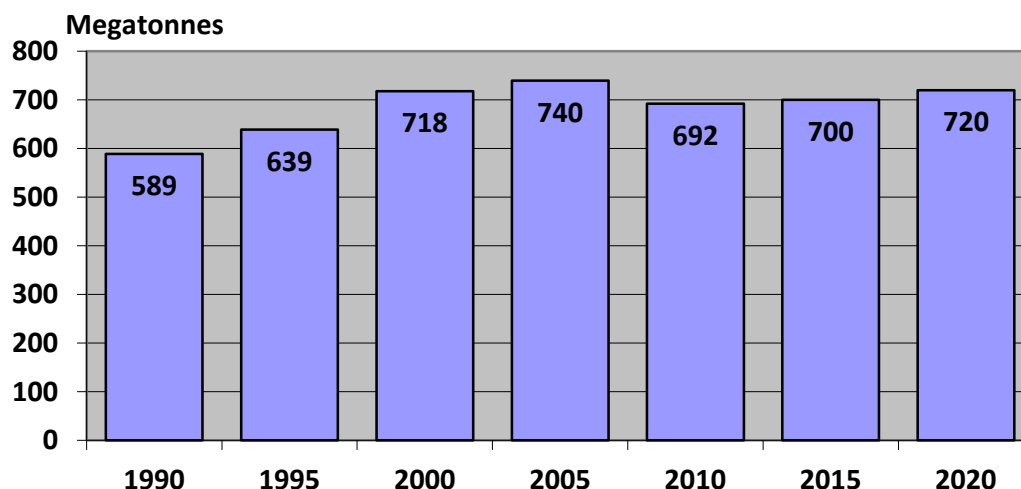
Cases	Impact on GHG emissions relative to the reference scenario (Mt CO ₂ e)		
	2005	2020	Change, 2005 to 2020
Slow GDP – High World Oil Prices	740	705	-35
Fast GDP – Reference World Oil Prices	740	771	31
Baseline Scenario	740	745	5
Sensitivity Range (including all scenarios examined – see Annex 2)	740	705 to 771	-35 to 31

Baseline Scenario Trends

National Emissions Projections

Figure 3 depicts the total projected Canadian greenhouse gas emissions⁸ in the absence of further government actions for selected years from 1990 to 2020. The projection suggests that Canadian emissions peaked in 2005. By 2020, emissions, including the contribution of LULUCF, are projected to be 720 Mt. This is comparable to the emissions level in 2000.

Figure 3 - Total Canadian GHG emissions and projections (with no further government actions): 1990 to 2020 (Mt CO₂e - incl. LULUCF)



Emissions Projections by Sector

Over the last two decades, the Canadian economy has become significantly less energy intensive and there continues to be an accelerated decoupling between economic growth and greenhouse gas emissions levels. Canada's total greenhouse gas emissions in 2010 were 692 Mt, and were essentially unchanged from 2009 levels with only a 0.25% increase. This means that between 2009 and 2010, Canada's emissions remained steady despite economic growth of 3.2%.

However, since a strong connection still remains between economic growth and greenhouse gas emissions, emissions are projected to rise over the period, but at a rate lower than economic growth. As the economy grows beyond 2010, total emissions

⁸ The projection period, 2011 to 2020, includes the contribution of land use, land-use change and forestry.

are expected to begin to increase. Absent further government action, by 2020 emissions are projected to reach 720 Mt, a decrease of 20 Mt from 2005.

Table 3 illustrates how the trends in each economic sector vary based on how economic drivers and government policies shape emissions in that sector. Electricity generation is the one major economic sector that is projected to reduce emissions significantly, in large part due to the combined impact of government measures to create a cleaner electricity system. Electricity emissions are projected to decline by 41 Mt (34%) between 2005 and 2020. On the other hand, increased production in the oil sands is expected to result in overall oil and gas emissions increasing by 44 Mt (28%) between 2005 and 2020.

The following pages provide more detail on expected emissions trends by economic sector.

Table 3 - Change in GHG emissions by economic sector (Mt CO₂e)

	2005	2020	Change, 2005 to 2020
Transportation	170	171	1
Electricity	121	80	-41
Oil and Gas	160	204	44
Emissions-Intensive Trade-Exposed Industries	90	83	-7
Buildings	85	91	6
Agriculture	67	65	-2
Waste and Others	48	51	3
Sub-Total	740	745	5
Expected LULUCF Contribution	N/A	-25	-25
Total	740	720	-20

Transportation

Total transportation emissions are projected to increase by about 1 Mt – from 170 Mt in 2005 to 171 Mt by 2020 – a marked deceleration of growth from the historical long-term trend. This deceleration is expected to occur as a result of higher gasoline and

refined petroleum prices, and greater fuel efficiency in vehicles being accelerated by federal vehicle emissions regulations⁹.

As depicted in Table 4, the transportation sector is comprised of several distinct subsectors – passenger, freight, and air and others (e.g., rail and marine)¹⁰. Each sector exhibits different trends and responds to a very different mix of technological options. For example, emissions from passenger transportation are projected to decrease by 11 Mt between 2005 and 2020, while those for ground freight and off-road are projected to grow by 11 Mt.

Under both phases of light duty vehicle regulations, spanning model years 2011 to 2025, the fuel efficiency of passenger vehicles will increase by some 35%. The sales-weighted fuel economy of new passenger vehicles is projected to improve from 7.9 L/100km in 2010 to 6.0 L/100km in 2020 and to 5.0 L/100km by 2025.

Likewise, emissions from freight are expected to decrease as a result of various federal, provincial and territorial programs. The recently announced Heavy Duty vehicle regulations will improve the average fuel efficiency of trucks from 2.5 litres/100 tonne-km to 2.1 litres/100 tonne-km by 2020.

Table 4 - Transportation: emissions (Mt CO₂e)

	2005	2010	2020
<i>Passenger Transport</i>	97	96	86
Cars, Trucks and Motorcycles	87	88	74
Bus, Rail and Domestic Aviation	9	8	12
<i>Freight Transport</i>	56	60	67
Heavy-Duty Trucks, Rail	49	52	58
Domestic Aviation and Marine	8	8	9
<i>Other: Recreational, Commercial and Residential</i>	17	10	18
Total Emissions (Mt)	170	166	171

⁹ See a description of federal Light-Duty Vehicle and Heavy-Duty vehicle regulations in the following section; as well as the “Drilldown” text box describing trends in light-duty vehicles.

¹⁰ There are many alternative approaches for treating and grouping the transportation activities. For example, passenger transportation could be included in the residential sectors. Likewise, moving of industrial freight could be included with each industry.

“DRILLDOWN” - Light-Duty Vehicle Emissions and Regulations

Transportation is a significant source of GHG emissions in Canada. In 2010, transportation sources accounted for 24% of total Canadian GHG emissions, of which 55% were emissions arising from the light-duty vehicle sub-sector (i.e. cars; small trucks). This has led the Government of Canada to target light-duty vehicles as a high priority for regulations.

In recognition of the integrated North American economies and transportation industry, the governments of Canada and the U.S. have established aligned policies for national regulations to reduce emissions from the transportation sector.

In October 2010, the Government of Canada released the final *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations (LVD1)*, which prescribes progressively more stringent annual emission standards for new vehicles of model years 2011 to 2016. The Government also published a *Notice of Intent* for “phase 2” of the regulations to develop more stringent GHG emissions standards for light-duty vehicles of model years 2017 to 2025 (LVD2).

These regulations will achieve significant and sustained GHG reductions and fuel saving benefits. By 2020, preliminary estimates suggest that Canadian regulations for model years 2011 to 2016 will lead to annual reductions of between 9 and 10 Mt in Canada. Preliminary estimates also suggest that the proposed regulations for model years 2017 to 2025 will contribute to achieving the Copenhagen 2020 target by reducing GHG emissions by an additional 2 to 3 Mt in 2020. Greenhouse gas emissions are expected to be reduced further beyond 2020, as the 2021 to 2025 reductions come into effect.

Under the first phase of the regulations, the average fuel efficiency of new vehicles is projected to increase by 15% between 2010 and 2016. The regulations continue to establish progressively stringent annual fleet average emission standards. Under the second phase of the regulations, average fuel efficiency of new vehicles is projected to increase by 37% between 2016 and 2025. Overall, the cumulative improvement from LDV1 and LDV2 is projected to increase the average fuel efficiency of new vehicles by 57% over the period from 2010 to 2025.

Unconventional vehicles (those that use diesel, alternative fuels, and/or hybrid electric systems) are projected to play a significant role in meeting more stringent fuel economy standards. This means that companies will continue to offer a full range of vehicle types to meet the transportation needs of Canadians, but that consumers can expect to see a greater choice of alternative vehicles available for sale. As a result, it is anticipated that the market penetration of existing advanced technology vehicles, such as hybrid-electric vehicles (e.g. Toyota Prius), plug-in hybrid-electric vehicles (e.g. Chevrolet Volt) and fully-electric vehicles (e.g. Nissan Leaf), will increase in Canada.

These vehicles have the potential to allow driving habits to change significantly, but, at the same time, reduce CO₂ emissions significantly. Moreover, electric vehicles offer zero tail pipe emissions since electricity is generated at centralized utilities which would significantly reduce localized smog and other air pollutant emissions.

Consumers that purchase a vehicle would be expected to recover any higher upfront costs through fuel savings between 5 to 8 years for passenger cars, and a period of only 2 to 4 years for light trucks. In fact, the lifetime fuel savings for a vehicle is projected to be 2 to 3 times the estimated increase in vehicle cost or approximately \$1,950 in 2025. Thus, the performance standard represents an economically efficient and low cost approach to emissions reductions. Under these regulations, greenhouse gas emissions from light-duty vehicles are projected to decrease by 16% between 2005 and 2020. Moreover, these regulations will have a significant impact on total transportation emissions. Canadian average annual Transport greenhouse gas emissions increased at 1.9% per year over 1990 to 2000 while they are projected to increase by only 0.4% on average over 2010 to 2020. As the second phase of the regulations take hold, and regulations for Heavy Duty Trucks increasingly impact other transport subsectors, average annual transport GHG emissions decrease by 4% from 2020 to 2030.

It is projected that there will be almost 26 million vehicles on the road by 2025. The emissions reduction of 15% due to the full phase in of LDV1 and LDV2 over the period from 2010 to 2025 would be equivalent to removing approximately 3.7 million vehicles from the road.

Oil and Gas

This projection does not include the impact of future oil and gas regulations. While work is currently underway, we have not yet reached a point where the effects can be reliably quantified. It is anticipated that these regulations will be included in Canada's Emission Trends in the future, and this inclusion will result in significant additional reductions by 2020 relative to the projections herein.

Upstream Oil and Gas Production

Absent further government action, emissions from upstream oil and gas production, including pipelines but excluding refining and upgrading¹¹, are estimated to grow from 125 Mt in 2005 to 160 Mt in 2020. This increase is primarily driven by the growth in bitumen production, where emissions are expected to increase from 19 Mt in 2005 to about 80 Mt by 2020. Specifically, emissions from oil sands mining are projected to double while emissions from in situ production are expected to increase more than five times from 10 Mt in 2005 to 55 Mt in 2020.

Over this same period, emissions from conventional crude oil production are expected to fall from 33 Mt in 2005 to 27 Mt in 2020, while those from natural gas production and processing are expected to fall from about 57 Mt in 2005 to 44 Mt by 2020.

Emissions from the pipeline transport of oil and natural gas are expected to fall from about 16 Mt in 2005 to 9 Mt by 2020. The emissions associated with the upgrading of

¹¹ Includes natural gas, conventional light and heavy crude oil, and in situ bitumen from oil sands.

oil-sands bitumen¹² are expected to rise from 14 Mt in 2005 to 23 Mt by 2020. Further details on emissions from oil-sands upgrading are reported in the section below dealing with the refining industry.

Table 5 - Oil and gas sector: emissions by production type (Mt CO₂e)

	2005	2010	2020	Absolute Change 2005 to 2020
Natural Gas Production and Processing	57	46	44	-13
Conventional Oil Production	33	29	27	-6
Conventional Light Oil Production	10	9	9	-1
Conventional Heavy Oil Production	21	18	15	-6
Frontier Oil Production	2	2	2	0
Oil Sands	32	48	104	73
Bitumen In situ	10	18	55	45
Bitumen Mining	9	13	25	16
Bitumen Upgrading	14	17	23	9
Oil and Natural Gas Transmission	16	11	9	-7
Downstream Oil and Gas	22	20	20	-2
Petroleum Products	20	18	18	-2
Natural Gas Distribution	2	2	2	0
Total	160	154	204	44

¹² By UNFCCC convention, emissions from the production of synthetic crude oil are linked to the petroleum refining industry.

Table 6 - Upstream oil and natural gas production: emissions and drivers

	2005	2010	2020
<i>Conventional Oil Production</i>			
Emissions (Mt CO ₂ e)	33	29	27
Production (1,000 barrels/day)	1361	1228	1112
<i>Natural Gas Production¹³ and Processing (including Pipelines)</i>			
Emissions (Mt CO ₂ e)	57	46	44
Production (billion cubic foot (BCF)) ¹⁴	6951	5868	4711
<i>Bitumen Production</i>			
Emissions (Mt CO ₂ e)	19	31	80
Production (1,000 barrels/day)	1064	1614	3263

Petroleum Refining and Upgrading

Table 7 displays emissions associated with petroleum refining and upgrading. As noted above, the greenhouse gas emissions from upgrading bitumen into synthetic crude oil are included in the petroleum refining industry category. From 2005 to 2020, emissions from bitumen upgrading are projected to increase by 9 Mt, while emissions from petroleum refining are projected to decline by 2 Mt.

¹³ Due to the increased prospects of shale gas in the United States and Canada (mostly British Columbia), the in-production date of natural gas from the Mackenzie Valley has been deferred until 2025.

¹⁴ For the most part, the oil and natural gas production projections reflect the views of the National Energy Board outlook for projects in these provinces. However, some adjustments have been made to reflect more recent market conditions. For example, the growth in shale gas production in British Columbia has been reduced.

Table 7 - Petroleum refining and upgrading sector: emissions and drivers

	2005	2010	2020
<i>Traditional Refineries</i>			
Emissions (Mt CO ₂ e)	20	18	18
Refined Petroleum Processed (1,000 barrels/day)	2165	2144	2359
<i>Upgraders</i>			
Emissions (Mt CO ₂ e)	14	17	23
Upgraded Products (1,000 barrels/day)	611	865	1359

Electricity Generation

Emissions from electricity generation and distribution have historically increased over time as a result of the need to increase generating output to supply a growing economy. However, emissions from this sector are now declining, and that trend is expected to continue over the next decade. Between 2005 and 2020, electricity generation emissions are expected to decrease by 41 Mt, from 121 Mt in 2005 to 80 Mt in 2020, as a result of the federal Emissions Performance Standard for coal-fired electricity generation as well as provincial measures to shift away from coal as a fuel source and measures to encourage the development of renewables.

Table 8 - Electricity sector: emissions and drivers

	2005	2010	2020
Emissions (Mt CO ₂ e)	121	99	80
Generation (TWh)	557	529	598

Against a backdrop of decreasing coal power usage, fossil fuel generation is expected to vary with the availability of electricity from hydro, nuclear and renewable power sources such as wind. Hydro power generation is expected to increase throughout Canada, although the growing demand for electricity in Alberta is expected to continue being met primarily through increased generation from coal and natural-gas-

fuelled power plants¹⁵. On a national level, electricity generation from natural gas, a relatively cleaner form of energy than coal, is expected to double between 2005 and 2020.

Table 9 - Electricity generation: emissions by fuel type (Mt CO₂e)

	2005	2010	2020	Absolute Change 2005 to 2020
Coal	98	80	57	-41
Refined Petroleum Products	9	2	3	-6
Natural Gas	13	16	19	6
Non-combustion	0	0	0	0
Total	121	99	80	-41

The proportion of utility electricity generation coming from wind power and other renewable sources (other than hydro and nuclear) increases in the 2005 to 2020 period, starting at only about 0.3% in 2005 and reaching 6% of total generation by 2020. These forms of electricity generation are assumed to be emissions free.

Emissions-Intensive and Trade-Exposed Industries

As shown in Tables 10 and 11, emissions in the emissions-intensive trade-exposed (EITE) industries (which include, among others, chemicals, pulp and paper, cement and iron and steel) are expected to experience modest growth as the economy recovers in 2010 and onwards. By 2020 emissions are projected to be 7 Mt lower than 2005 levels, at 83 Mt.

¹⁵ Note that four new coal fired plants are assumed to be constructed or refurbished with carbon capture capabilities in Saskatchewan.

Table 10 - Emissions-intensive and trade-exposed industries: emissions and drivers

	2005	2010	2020
Emissions (Mt CO ₂ e)	90	75	83
Gross Output of EITE sectors (1997 \$billions)	139	121	134

Emissions remain stable over the 2005 to 2020 projection period in most of the EITE subsectors, owing to modest growth and continued improvements in emission intensities. Emissions are expected to decrease in the pulp and paper and base metal smelting subsectors while mining is increasing.

Table 11 - Emissions-intensive and trade-exposed industries: emissions by subsector (Mt CO₂e)

	2005	2010	2020	Absolute Change 2005 to 2020
Mining	6	8	8	2
Smelting and Refining (Non-ferrous metals)	13	10	11	-2
Pulp and Paper	9	7	6	-3
Iron and Steel	20	14	19	-1
Cement	12	10	12	0
Lime & Gypsum	3	3	3	0
Chemicals and Fertilizers	26	24	24	-2
Total	90	75	82	-8

Buildings

Residential

As shown in Table 12, greenhouse gas emissions from the residential sector (e.g., houses, apartments and other dwellings) are expected to remain stable between 2005 and 2020.

The number of households, which is a key driver of growth in residential sector emissions, is expected to increase by 2.8 million from 2005 to 2020 but residential emissions are almost flat throughout this period. This is largely due to federal and provincial measures aimed at increasing the energy efficiency of residential buildings (e.g., building code regulations and incentives/rebates for energy efficiency improvements).

Table 12 - Residential sector: emissions and drivers

	2005	2010	2020
Emissions (Mt CO ₂ e)	42	41	43
Households (Millions)	12.1	13.0	14.74

Service Industry

Greenhouse gas emissions from Canada's service industry are expected to increase by 5 Mt from 2005 to 2020 to 48 Mt (Table 13), mainly as a result of expansion of commercial floor space. As in the residential sector, emissions growth in the commercial sector is significantly dampened by federal and provincial measures incorporated into this analysis, such as building code regulations, energy efficiency standards, and other programs.

Table 13 - Commercial sector: emissions and drivers

	2005	2010	2020
Emissions (Mt CO ₂ e)	43	38	48
Floor space (Millions m ²)	1106	1248	1552

Agriculture

The agriculture sector produces emissions of three greenhouse gases: carbon dioxide, methane and nitrous oxide. Carbon dioxide emissions are released from fossil fuel combustion in farm machinery; methane emissions arise from livestock manure and ruminant animals; and nitrous oxide emissions arise from fertilizer usage, crops and manure and crop residue burning. Emissions from the agriculture sector are projected to decrease by 4 Mt from 69 Mt in 2010 to 65 Mt in 2020.

Table 14 - Agriculture sector: emissions (Mt CO₂e)

	2005	2010	2020
Agriculture¹⁶			
On-Farm Fuel Use	9	13	10
Crop Production	19	22	22
Animal Production	39	33	33
Total	67	69	65

Waste and Others

This sector includes emissions from waste management as well as from non-emissions-intensive industrial sectors. Emissions from this sector are projected to grow moderately, leading to emissions growth of 3 Mt between 2005 and 2020.

Emissions from waste management arise from three sources: emissions from the decomposition of solid waste in landfill sites, emissions from wastewater treatment and incineration of waste. These emissions represent 6% of total GHG emissions in 2010. For these emissions, population and households are the main drivers. Provincial measures aimed at recycling and emissions capture from landfill sites are projected to help keep emissions growth below the growth in population and household formation. Emissions from waste are projected to remain stable.

Emissions from other industrial sectors represent a wide variety of operations and include construction, forestry as well as light-manufacturing facilities (e.g. food and beverage, and electronics) and coal production. These industries are projected to grow moderately, leading to emissions growth of 2 Mt between 2005 and 2020.

¹⁶ Includes emissions not related to energy use such as methane from livestock manure and ruminant animals and nitrous oxide from fertilizer usage, crops and manure.

Table 15 - Waste and Others: emissions (Mt CO₂e)

	2005	2010	2020
Waste & Others			
Waste	22	22	23
Coal Production	2	5	3
Light Manufacturing, Construction & Forest Resources	23	23	25
Total Waste and Others	48	50	51

Emissions by Province

Emissions vary significantly by province, driven by diversity in population size, economic activities, and resource base among other factors. For example, provinces where the economy is oriented more toward resource extraction have more uncertainty around the timing of large projects and will tend to have higher emission levels whereas more manufacturing or service-based economies tend to have lower emissions levels. Electricity generation sources also vary, with provinces that rely on fossil fuels for their electricity generation having higher emissions than provinces that rely more on hydroelectricity. Table 16 shows the provincial/territorial distribution of emissions in absolute terms as well as their per capita emissions.

The provinces oriented toward resources extraction and/or are highly reliant on fossil fuels for their electricity generation (i.e., Alberta, Saskatchewan, New Brunswick, and Nova Scotia) have per capita emissions above the national average. The provinces oriented toward manufacturing or services or are highly reliant on hydroelectricity or less emission intensive sources for their electricity generation (i.e., Quebec, British Columbia, Ontario, Newfoundland and Labrador and Manitoba) have per capita emissions below the national average.

Table 16 - Provincial and territorial GHG and per capita emissions: 2005 to 2010

	GHG Emissions (Mt CO ₂ e)		Per Capita Emissions (t/capita)	
	2005	2010	2005	2010
British Columbia	63	56	15.0	12.4
Alberta	232	236	69.8	63.4
Saskatchewan	71	73	71.1	69.8
Manitoba	21	20	17.9	16.3
Ontario	206	172	16.4	13.0
Quebec	86	82	11.4	10.4
New Brunswick	22	18	29.8	24.5
Nova Scotia	24	20	25.3	21.7
Newfoundland	10	9	19.8	16.9
Prince Edward Island	2	2	16.2	13.8
Territories	2	2	21.9	18.8
Canada	740	692	22.9	20.3

Table 17 displays projected provincial and territorial greenhouse gas emissions from 2005 to 2020. The projected emissions reflect a diversity of economic factors and government measures to reduce GHG emissions. These include public education

campaigns, energy efficiency and renewable electricity programs, greening government operations carbon taxes or levies (i.e., British Columbia, Alberta and Quebec), regulatory measures, and legislated renewable electricity targets.¹⁷

It should be noted that the increase in emissions in British Columbia and Alberta are driven by large natural resource projects; oil sands in the case of Alberta and natural gas in the case of British Columbia. For the most part, the oil and natural gas production projections reflect the views of the National Energy Board outlook for projects in these provinces, but there is an intrinsic level of uncertainty as to the timing of them that affects the projected GHG emissions¹⁸. The decline in emissions from 2005 to 2020 in Saskatchewan, Ontario, New Brunswick and Nova Scotia are due in large part to government measures related to coal-fired electricity.

Table 17 - Provincial and territorial GHG emissions: 2005 to 2020 (Mt CO₂e)

	2005	2010	2020	Change 2005 to 2020
British Columbia	63	56	72	9
Alberta	231	237	285	53
Saskatchewan	71	73	64	-7
Manitoba	21	20	21	0
Ontario	206	172	167	-39
Quebec	86	82	85	-1
New Brunswick	23	19	17	-5
Nova Scotia	24	20	17	-7
Prince Edward Island	2	2	2	0
Newfoundland	10	9	10	0
Territories	2	2	3	1
LULUCF			-25	
Canada	740	692	720	-20

¹⁷ While provincial and territorial have announced a diverse range of measures, only measures which could be readily modeled or have an announced regulatory or budgetary dimension were modeled. Aspirational goals and targets that were not supported by measureable, real and verifiable actions were not included.

¹⁸ The growth in shale gas production in British Columbia has been reduced to reflect more recent market conditions.

Table 18 displays projected provincial and territorial per capita greenhouse gas emissions in 2020 and compares them to actual emissions in 2005 and 2010. Per capita emissions are projected to fall in all provinces in 2020, except for British Columbia and Alberta. British Columbia's per capita emissions are projected to increase due to the pace of natural gas development. Despite this increase, British Columbia's per capita emissions are projected to remain below the national average.

Table 18 - Provincial and territorial per capita emissions: 2005 to 2020

	2005	2010	2020
British Columbia	15.0	12.4	14.3
Alberta	69.8	63.4	63.6
Saskatchewan	71.1	69.8	54.7
Manitoba	17.9	16.3	15.1
Ontario	16.4	13.0	11.7
Quebec	11.4	10.4	10.0
New Brunswick	29.8	24.5	21.8
Nova Scotia	25.3	21.7	18.1
Prince Edward Island	16.2	13.8	12.3
Newfoundland	19.8	16.9	20.3
Territories	21.9	18.8	26.8
Canada	22.9	20.3	19.2

The Land Use, Land-Use Change and Forestry Sector

Importance of the LULUCF Sector

The United Nations Framework Convention on Climate Change (UNFCCC) has recognized the important role of the “land use, land-use change and forestry” (LULUCF) sector in addressing climate change. The LULUCF sector involves greenhouse gas (GHG) fluxes between the atmosphere and Canada’s managed lands, as well as those associated with land-use change. Globally, land-use change was responsible for estimated net carbon flux to the atmosphere of about 1.47 GtC in 2005. In comparison, global carbon dioxide (CO₂) emissions from fossil-fuel burning and cement manufacture emitted about 8.09 GtC in 2005.¹⁹

Land management activities can either act as a carbon dioxide sink (i.e., remove CO₂ from the atmosphere) or a GHG source (emit CO₂ and other GHGs to the atmosphere). For example, afforestation, or planting trees on non-forest land, removes carbon from the atmosphere as the trees grow; but deforestation, or conversion of forest land to other land uses, will increase CO₂ emissions due to decomposition or burning of the biomass.

LULUCF is a particularly important sector for Canada given that 10% of the world’s forests are in Canada and our managed forest covers 229 million hectares, more than the managed forest of the entire European Union. Canada also has 47 million hectares of cropland.

Over the last two decades, important changes have occurred in land management practices in Canada that have reduced CO₂ emissions or enhanced their removals from the atmosphere. For example, farmers have increasingly adopted no-till practices and reduced summer fallow practices, thereby increasing the rate of soil carbon sequestration. Best practices have also been adopted by the forestry sector, primarily as a result of provincial policies and/or regulations in their areas of jurisdiction.

Although these policies and regulations are aimed broadly at improving sustainability in the sector, they also reduce carbon emissions and increase sequestration. They include: relatively more reliance on tree planting as opposed to natural regeneration; more use of improved seed stock for tree planting; more and faster rehabilitation of harvest roads and landings; and adjustment in management practices to reduce soil compaction. Recently, economic factors have had a large impact on the forest sector which experienced a 43% decline in harvest levels between the peak year of 2004 and 2009, resulting in the lowest harvest since 1975²⁰.

¹⁹ Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tenn., U.S.A.
<http://cdiac.ornl.gov/trends/landuse/houghton/houghton.html>

²⁰ National Forestry Database Program, www.nfdp.ccfm.org.

Accounting for the LULUCF Sector

While GHG emissions from the LULUCF sector are included in Canada's annual National Inventory Report, the sector was left out of Canada's first national Emissions Trends report published in 2011, primarily as a result of technical challenges in forecasting emissions and removals from LULUCF and because accounting approaches for the sector had not yet been determined.

A unique challenge in forecasting LULUCF emissions resides in addressing the effects of natural disturbances (e.g. wildfires, insect infestations such as the mountain pine beetle), which can result in significant variations in the annual emission and removal estimates but are very difficult to project. The impact of natural disturbances also makes it difficult to discern the effects of improved management practices.

Environment Canada's National Inventory Report, which is used to measure current Canadian GHG emissions, currently includes estimates of emissions and removals with natural disturbances. The National Inventory Report is submitted to the United Nations Framework Convention on Climate Change (UNFCCC) on an annual basis.

The difficulties related to accounting for LULUCF emissions and removals are widely-recognized in the international community. In particular, challenges related to natural disturbances have been the subject of considerable technical work over the past several years. Acknowledging that natural disturbances are out of human control, it was finally agreed at the 2011 UNFCCC Climate Conference in Durban, South Africa, that the impacts of natural disturbances can be removed in accounting for forest management in 2013 and thereafter.

The UNFCCC guidelines for GHG inventory reporting were also updated in Durban to allow reporting estimates that better represent the direct effect of human activities, taking into account national circumstances. These new guidelines will come into effect for the 2015 National Inventory Report submission. Going forward, and on the basis of these new decisions, Canada will continue to explore options for revised reporting that provides a more accurate representation of emissions arising from human activities.

In a spring 2012 submission to the UNFCCC, Canada, along with a number of other countries, stated its intent to include the LULUCF sector in its accounting of GHG emissions towards its 2020 target, noting that emissions and related removals resulting from natural disturbances would be excluded from the accounting.

This 2012 Emissions Trends Report represents a key milestone for Canada in moving towards the inclusion of the LULUCF sector in projecting GHG emissions. While the estimates presented are preliminary in nature and will change as a result of ongoing efforts to improve data and methodology, as well as continued analysis of various approaches to accounting for LULUCF, they provide a solid first step toward understanding the underlying trends of LULUCF that will enable a policy discussion and the implementation of new measures to make further progress towards Canada's GHG reduction goals.

Subsector Analysis

Environment Canada, in partnership with Natural Resources Canada and Agriculture and Agri-Food Canada, has undertaken research and analysis over the past year to develop preliminary projections of LULUCF emissions and removals. Projected business-as-usual emissions and removals (i.e. in the absence of new policies that contribute to mitigation) have been estimated to 2020 for each of the following subsectors: forest management, cropland management, deforestation and afforestation²¹. Table 19 below shows preliminary results for each of the subsectors assessed.

Table 19 - Projected emissions (+) or removals (-) from the LULUCF sector in 2020

(In Mt of GHG emissions/removals)	2020 Projected Emissions/Removals	2005 Estimate/Reference Level	Expected Contribution to 2020 Emissions
Forest Management	-148.7	-122.6*	-26.1
Cropland Management	-9.8	-10.0	+0.2
Deforestation	+13.8	+14.2	-0.4
Afforestation	-1.3	-0.6	-0.7
Totals	-146	-119	≈-25**

* For forest management, a 2020 reference level is used for comparison (explained in further detail below).

** As a conservative estimate, the total is rounded down to 25 Mt, given that estimates are preliminary and will be revised as modeling methodology, accounting approaches and data are further refined.

Each subsector's contribution to Canada's 2020 emissions reduction target is estimated using an accounting approach that compares projected business-as-usual 2020 emissions/removals to 2005 emissions/removals, with the exception of forest management, where 2020 projected emissions/removals are compared to a 2020 reference level.

The rules agreed in Durban for LULUCF included a reference level for forest management, proposed by Canada, for the 2013 to 2020 period²². Canada's reference level is consistent with data in the National Inventory Report and was derived by

²¹ Cropland management projections have been modeled by Agriculture and Agri-Food Canada; Forest Management and Afforestation projections have been modeled by Natural Resources Canada, and Environment Canada developed projections for Deforestation based on analysis provided by Natural Resources Canada.

²² Canada's submission on its reference level for 2013-2020 is described in a submission to the UNFCCC at <http://unfccc.int/bodies/awg-kp/items/5896.php>.

assuming that future harvests in 2013 to 2020 would be the same as the average historical level between 1990 and 2009. As well, the reference level excluded all natural disturbance impacts after 2009, except a low background level expected to occur every year. As Canada's target is focused on the single year of 2020, the 2020 value used in constructing the reference level is used here. The reference level approach factors out highly variable natural disturbance impacts.

In Durban, parties agreed to LULUCF accounting rules for the Kyoto Protocol's second commitment period. Parties to the UNFCCC that will not take a second commitment period may follow these rules but are not bound to do so. The U.S., for example, in a submission to the UNFCCC in 2012, indicated it will include LULUCF when accounting for its 2020 target and that it will use a net-net approach for the LULUCF sector with a 2005 base-year. Canada's submission stated that LULUCF will be accounted for using either a 2005 base-year or a reference level.

Given this context, Canada's work to analyze alternative accounting approaches is ongoing, and adjustments to the accounting approach may be made in future Emissions Trends reports. In particular, alternative accounting approaches may need to be considered given that accounting approaches for LULUCF continue to vary internationally and there remains uncertainty with respect to future approaches under a proposed new climate change agreement beyond 2020.

Subsector Emission Trends and Methodologies

Further detail on Canadian emission trends and methodologies used are provided for each of the subsectors below:

- **Forest Management²³**. As per Table 19, the Forest Management subsector dominates the expected LULUCF contribution in 2020, as a result of declining harvest rates. Harvesting is the human activity with the most impact on emissions in the managed forest. Harvest levels declined by 43% between the peak harvest year of 2004 and a 35-year low in 2009 before recovering somewhat in 2010. Current projections suggest that harvests will remain below the recent average historical level used in estimating the reference level. The projected value for the forest management sink in 2020 is derived by using projected harvests to 2020 and assuming no natural disturbances from 2010 onward except a low background level expected to occur every year, compared with the reference level.
- **Cropland Management²⁴**. Due largely to the uptake of new farming practices (e.g. the increased adoption of no-till), soil carbon sequestration in Canada has increased over time from a rate of 1.5 Mt per year in 1990 to 1.3 Mt per year in 2010 (NIR, 2012). Currently, most of the land where no-till makes economic sense is already using this practice, so there is limited scope for increased uptake. Furthermore, the potential for land that has been in no-till for a long

²³ The category of "forest management" includes only the area of forest managed for timber and non-timber resources (including parks) or subject to fire protection.

²⁴ Cropland management applies to land that is used for crop production as well as land temporarily not being used for crops.

time (i.e. in excess of 20 years) to sequester more carbon decreases over time. Therefore, while soils will continue to sequester carbon (at a projected rate of 9.8 Mt in 2020), they will do so at a lower annual rate than in 2005 (when the rate was 10 Mt). Because accounting for emissions/removals for cropland management is on a net basis relative to 2005, this results in a small reduction in the overall LULUCF contribution in 2020. However, this does not indicate that a reversal of the stock of carbon in the soil has occurred.

- **Deforestation/Afforestation²⁵**. Current deforestation rates in Canada are estimated at 44,000 hectares per year, down from 65,000 hectares per year in 1990. Part of the emissions due to deforestation occurs immediately upon the deforestation event, while the remaining emissions take place over subsequent years and decades. Deforestation emissions are projected to decline slightly to 2020 relative to 2005, whereas afforestation removals are expected to increase as a result of a slow increase in the area planted since 1990 and growth of the trees. The circumstances surrounding deforestation activities in Canada are extremely varied and involve a wide range of economic sectors (agriculture, urban expansion, resource extraction). As such, projections presented in this report will be adjusted as a result of revised projections of economic growth and conditions for each of these sectors.

Work is currently underway to also develop estimates for Peatland Management that will be added to next year's LULUCF estimates.

Contribution of the LULUCF Sector to 2020 Projected Emissions

On the basis of preliminary estimates, the projected contribution of the LULUCF sector to achieving the 2020 target is approximately 25 Mt. This estimated contribution, while illustrative of the potential, may change as subsector projections are refined over time as a result of further analysis, new data, updated projections, or adjusted accounting approaches.

As the Government of Canada works towards achieving its climate change objectives, it will consider, along with its provincial and territorial partners, policy actions to achieve further mitigation results from the LULUCF sector. Key LULUCF activities in Canada with potential for increasing mitigation benefits through reducing emissions or increasing removals include changing forest management practices, increasing afforestation, decreasing deforestation, enhancing agricultural practices that sequester carbon and possibly restoring managed peatlands. In addition to climate change mitigation, such efforts could positively impact other environmental or economic objectives. For example:

²⁵ The categories of deforestation and afforestation refer to a permanent change in the way that land is used. Deforestation is the permanent conversion of forest land to other land uses such as agricultural land, transportation infrastructure, mines or urban areas. Forest clearing due to harvesting is expected to be temporary and is not included in this category – it is included in forest management. Conversely, afforestation is the permanent conversion of non-forest land (usually agricultural land in Canada) to forest.

- Deforesting one hectare of forest emits on average approximately 300 tonnes of CO₂e; policies aimed at reducing deforestation would have climate change benefits and could also address other environmental issues, such as biodiversity conservation.
- Increased adoption of farming practices such as no-till will also provide long-term benefits to farmers by improving soil quality and reducing erosion while increasing soil carbon sequestration.
- Mitigation practices such as increasing afforestation, reducing deforestation or restoring abandoned peatlands can also lead to creation and protection of wildlife refuges.

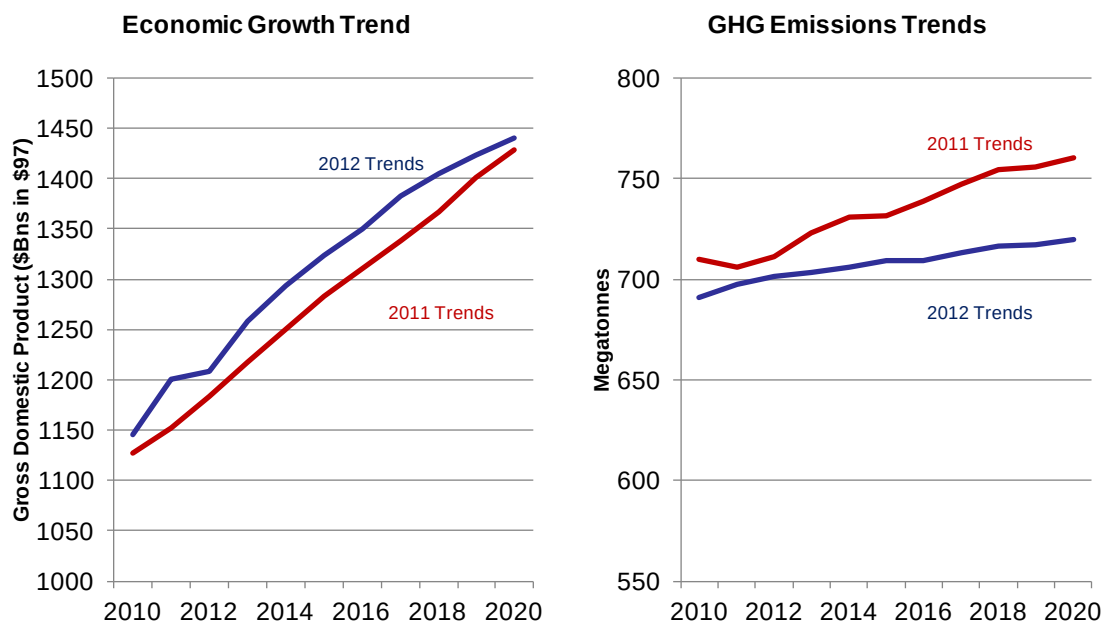
Emissions Intensity Improvements and Federal, Provincial and Territorial Actions

Last year, Canada's 2020 GHG emissions were projected to be 785 Mt in 2020. Since that time, there have been several key developments and GHG emissions are now projected to be 65 Mt lower at 720 Mt in 2020. This is despite the fact that GDP is projected to be slightly higher in 2020 in this year's projection. This reduction in GHG intensity implies a greater decoupling of emissions and economic growth.

As shown in Figure 4, while GDP growth is similar when compared with last year's report, emissions growth is slower. While GDP is expected to grow approximately 2.3% per year between 2010 and 2020, GHG emissions are only expected to grow 0.4% per year over the period. This leads to a total emissions intensity improvement of 14% over the period – an increase over the 13% improvement in last year's report.

In addition to the inclusion of reductions associated with LULUCF, there are a number of factors contributing to the increased emissions intensity improvement.

Figure 4 - Decoupling of GDP and GHG emissions - 2010 to 2020



First, this year's projections have a new, lower starting point as the most recent data show emissions were significantly lower in 2010 than previously estimated. Last year, emissions were estimated to be 710 Mt and since that time, preliminary data collected by Statistics Canada and assessed for the National Inventory Report put Canada's actual emissions in 2010 at 692 Mt. Contributing factors to this change were lower than expected natural gas production and slower growth in some emissions-intensive sectors.

Secondly, economic growth is projected to be slower in some emissions-intensive and light industry sectors. Projected sectoral shifts in the economy are contributing to the

improvement in emissions intensity. Compared to last year's report, projected growth for the EITE sectors, specifically iron and steel and pulp and paper, is now lower, while it is now higher for the service industries which are less emissions intensive. GDP in Canada's services industry, where emissions intensity is low, increases as a share of the total. This reduces projected emissions in 2020, even though total GDP is projected to be slightly higher.

Table 20 - Selected industries' share of GDP in 2020 (%)

	2011 Trends	2012 Trends	Change from last year's report
Electricity	1.7	1.9	+0.2
Oil and Gas	2.5	2.6	+0.1
Emissions-Intensive Trade-Exposed Industries	4.2	3.9	-0.3
Light Industry	18.7	17.8	-0.9
Agriculture	1.3	1.4	+0.1
Total Goods	28.5	27.6	-0.9
Total Services	71.5	72.4	+0.9

Thirdly, progress is being made to reduce emissions. Supported by existing government measures, there is greater response from consumers and businesses to reduce emissions. Emissions are also declining with additional federal, provincial and territorial measures. In addition, additional federal emissions regulations for light-duty vehicles for the 2017-2025 period as well as heavy-duty vehicle regulations were included as well as recent provincial actions (e.g., Quebec's cap-and-trade, Nova Scotia's emissions cap for electric utilities, increased stringency of building energy codes, equipment standards and requirements for capturing methane from landfill gas). Additional details on these existing federal and provincial measures are provided in Annex 1.

More work is required to achieve the reductions required to meet the Canadian target. Work is underway that will lead to additional reductions. As the government advances additional measures under its climate change plan, future emission reductions will continue to accumulate, thereby pushing projected emissions in 2020 down towards the levels required to meet the 2020 target. For example, the Government of Canada is currently working in partnership with the oil and gas industry to regulate greenhouse gas emissions. Once the details of these measures have been announced and they are taken into account in the baseline scenario, projected emissions in 2020 will decline further below the projected levels shown here. Similarly, once additional measures in other sectors and additional provincial actions are announced and taken into account, projected emissions in 2020 will decline even further.

Annex 1

Baseline Data and Assumptions

Key Economic Drivers and Assumptions

Many factors influence the future trends of Canada's greenhouse gas emissions. These key factors include the pace of foreign and domestic economic growth as well as its composition, population and household formation, energy prices (e.g., world oil price and the price of refined petroleum products, regional natural gas prices, and electricity prices), technological change, and policy decisions. Varying any of these assumptions could have a material impact on the emissions outlook.

In constructing the emissions projections, Environment Canada developed alternative views of changes in key drivers (e.g., world oil price, the pace of economic growth) that result in a range of plausible emissions growth trajectories. The baseline emissions projections scenario represents the mid-range of these variations, but remains conditional on the future path of the economy, world energy markets and government policy. The assumptions and key drivers are listed in this section. Alternative cases are explored in the sensitivity analysis in Annex 2 of the paper.

The emissions projections baseline scenario is designed to incorporate the best available information about economic growth as well as energy demand and supply into the future. The projections capture the impacts of future production of goods and services in Canada on greenhouse gas emissions.

Economic assumptions are based on the Government of Canada's short-term economic outlook contained in Finance Canada's Budget 2012 private sector economic survey. Long-term economic projections were developed using *The Informetrica Macro-Economic Model* (TIM) and are tuned to productivity growth projections and Statistics Canada's population growth projections. With respect to major energy supply project assumptions, Environment Canada typically adopts either the National Energy Board or Natural Resources Canada's view regarding the evolution of Canada's energy supply sector. For the emissions outlook in this report, forecasts of major energy supply projects are based on the National Energy Board's Fall 2011 Outlook, as their assumptions reflect their most recent views regarding the evolution of Canada's energy supply sector.

The projections also incorporate data from the National Inventory Report 1990-2010: Greenhouse Gas Sources and Sinks in Canada, the National Energy Board, and the U.S. Energy Information Administration for the latest information on key parameters.

Economic Growth

Canadian real gross domestic product (GDP) in 2010 was an estimated \$1,146 billion (\$1997). This represents an average annual real GDP growth rate of about 2.4% over the twenty previous years.

The short-term economic outlook underlying the emissions reference case is grounded in the GDP growth forecast contained in Budget 2012. The Department of Finance regularly surveys private sector economic forecasters on their views on the outlook for the Canadian economy. The economic forecasts reported in this fiscal update, and which also form the basis of the department's fiscal forecasts, are based on a survey from March 2012 and includes the views of 14 private sector economic forecasters²⁶.

The Canadian economy is expected to show strong growth of about 3.1% per year to 2014. This growth is expected to continue at a slightly slower pace into the future, as annual rate of growth in real GDP decreases to approximately 1.8% in the period 2014 to 2020.

Table A.1.1 - Macroeconomic assumptions: 1990-2020 average annual growth rates (%)

	1990-2005	2005-2010	2010-2020
Gross Domestic Product	2.8%	1.2%	2.3%
Industrial Gross Output	2.8%	0.8%	2.3%
Real Disposable Personal Income	1.6%	4.2%	2.4%
Consumer Price Index	2.1%	1.6%	1.8%

Gross output, which is a proxy for industrial production, is also projected to show significant growth. It is expected to increase by about 16% by 2015 and 26% by 2020, relative to 2010 levels.

The growth in the labour force and changes in labour productivity influence the changes in Canada's real gross domestic product (GDP). For example, the slowing growth in the labour force contributes to a reduced GDP growth rate after 2014. The deceleration of the GDP growth rate is, however, not as pronounced as that of the labour force, as labour productivity is expected to increase owing to higher capital formation. Labour productivity is expected to increase on average by 1.4% per year between 2010 and 2020.

²⁶ <http://www.budget.gc.ca/2012/plan/chap2-eng.html#a22>

Population Dynamics and Demographics

The population size and its characteristics (e.g., age, sex, education, household formation, among others), and their evolution through time, have important impacts on energy demand. Canada's overall population is projected to grow on average at an annual rate of 1% between 2010 and 2015, slowing to 0.9% between 2015 and 2020. Major demographic factors that can have measurable impacts on energy consumption are summarized below:

- *Household formation.* This is the main determinant of energy use in the residential sector. The number of households are expected to increase on average by 1.3% per year between 2010 and 2015, and by 1.2% between 2015 and 2020.
- *Labour force.* This is expected to have a decelerating growth rate, reflecting the aging population. Its annual average growth rate is expected to be 1.1% between 2010 and 2015 falling to 0.6% between 2015 and 2020.
- *Population of driving age.* This is an important factor in determining gasoline and diesel consumption. It is expected to increase on average by 1.1% per year between 2010 and 2015, by 0.9% between 2015 and 2020.

World Crude Oil Price

A major factor in projected greenhouse gas emissions is the assumption made about future world oil prices. Canada is a price taker in crude oil markets as its shares of world oil production and consumption are not large enough (4% and 2% respectively) to significantly influence international oil prices. West Texas Intermediate (WTI) crude oil is used as an oil price benchmark. North American crude oil prices are determined by international market forces and are most directly related to the WTI crude oil price at Cushing, which is the underlying physical commodity market for light crude oil contracts for the New York Mercantile Exchange (NYMEX). WTI crude has an American Petroleum Institute gravity²⁷ (API) of 40 degrees and a sulphur content of less than 0.5%. It should be noted that the increase in North American supply and the resulting transportation bottleneck at Cushing have created a historic disconnect between the WTI and Brant. As such, the North American oil market is currently being priced differently from the rest of the world.

The emissions outlook's reference case is anchored by the world oil price assumptions developed by the National Energy Board. According to the National Energy Board, the world crude oil price for WTI is projected to increase slightly from about US\$80/bbl in 2010 to about US\$102/bbl in 2020. A higher price scenario, in which 2020 prices are US\$142/bbl, is used for sensitivity analysis. Under the higher price case, greenhouse gas emissions are expected to be lower.

²⁷ API gravity is a measure of how heavy or light a petroleum liquid is compared to water.

Figure A.1.1 - Crude oil price: WTI, Western Canada Select and Alberta Heavy (\$US 2010/bbl)

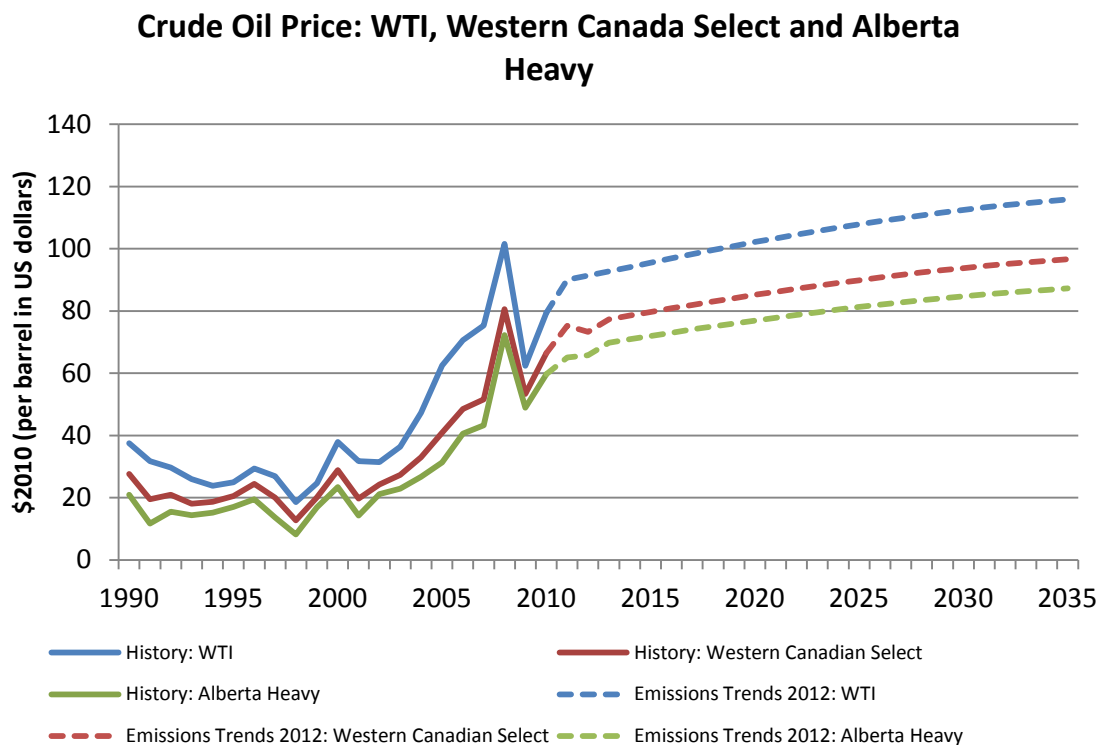


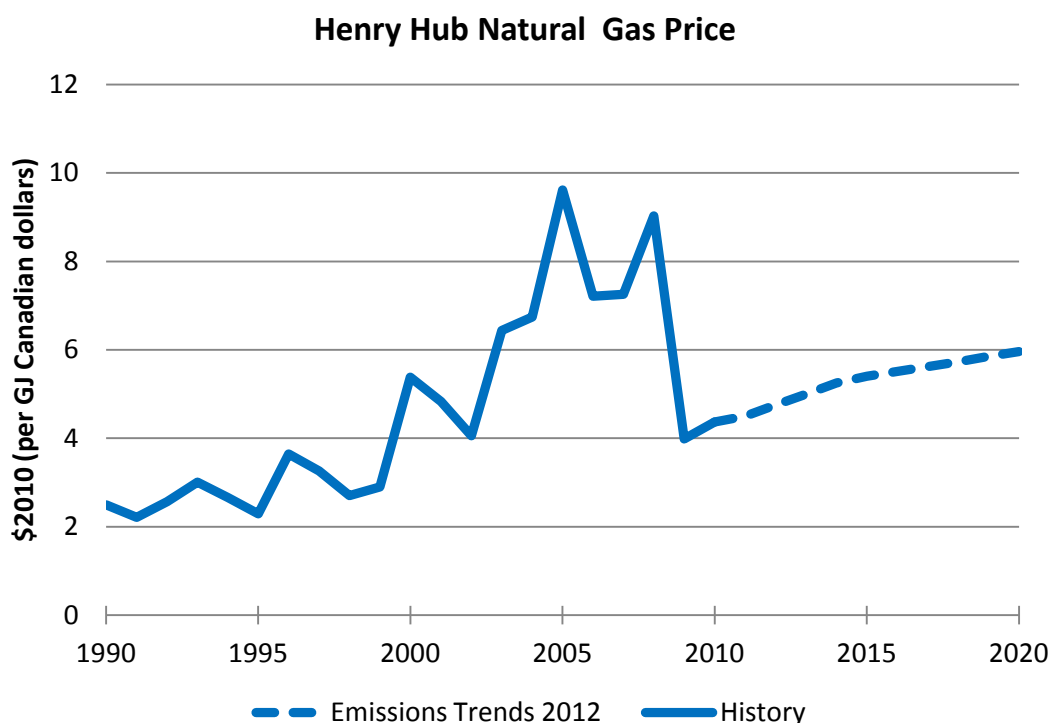
Figure A.1.1 shows crude oil prices for light crude oil (WTI), for Western Canadian Select, which is a Hardisty based blend of conventional and oilsands production managed by Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy and for Heavy oil. As shown in Figure A1.4, historically the price of heavy oil/bitumen has followed the light crude oil price (WTI), but at a discount of between 50 and 60%. However, in 2008 and 2009 the differentials between the prices of light and heavy crude oils narrowed significantly owing to a global shortage of heavier crude oil supply. The bitumen/light-medium differential averaged 22% over the 2008 to 2009 period, compared with 44% over the five-year average from 2003 to 2007.

Alberta's Energy Resources Conservation Board expects the bitumen/light-medium differential to average 26% over the forecast period, compared with the five-year average of 36% and the 2009 average of 17%.²⁸ Using this price difference, the Western Canada Select price is increasing slightly from about US\$60/bbl in 2010 to about US\$87/bbl in 2020.

²⁸ http://www.ercb.ca/docs/products/STs/st98_current.pdf

As shown in Figure A.1.2, the Henry Hub price for natural gas in Alberta (the benchmark for Canadian prices) declined in 2010 to about four Canadian dollars per gigajoule (GJ). In the projection, it begins to recover to reach about six Canadian dollars per GJ by 2020, still well below its peak of almost \$10 in 2005. This reflects the National Energy Board's assumptions regarding pipeline expansions (e.g., Mackenzie and the Alaska pipelines).

Figure A.1.2 - Henry Hub natural gas price (\$CDN 2010/GJ)



Energy Production

Historically, growth has occurred in all areas of oil and gas production, with over half the growth coming from natural gas production. However, our projections show that both natural gas and conventional oil production will decrease over time as a result of declining supply, but that the projected increase in production from oil sands operations will more than make up for this decline. As such, under assumed prices and absent further government policy actions, it is expected that from 2010 to 2020 oil sands in situ production will almost triple and oil sands mining production will increase by 50% (see Table A.1.2, below).

Table A.1.2 - Crude oil production

Thousand Barrels Per Day	2005	2010	2020
Crude and Condensates			
Conventional Heavy	526	425	363
Conventional Light	511	512	524
C5 & condensates	173	148	137
Frontier Light (offshore + northern)	324	291	225
Oil Sands – Primary	150	194	211
Oil Sands – In-situ	286	563	1607
SAGD	82	319	1267
CSS	204	244	340
Oil Sands Mining	628	857	1445
Total Production (gross)	2,598	2,990	4,512

Table A.1.3 illustrates oil sands disposition. There are two main products from oil sands production: synthetic crude oil (or upgraded bitumen) and non-upgraded bitumen, which is sold as heavy oil. Synthetic crude oil production (A.1.3) from Alberta is projected to increase from about 794,000 barrels per day in 2010 to about 1.29 million barrels per day by 2020. Synthetic crude oil from Saskatchewan is projected to remain constant at 70,000 barrels per day. Non-upgraded bitumen will increase from 612,000 barrels per day in 2010 to 1.69 million barrels per day by 2020. This non-upgraded bitumen is either sold as heavy oil to Canadian refineries or transported to U.S. refineries for upgrading to refined petroleum products.

Table A.1.3 - Oil sands disposition

Thousand Barrels Per Day	2005	2010	2020
Synthetic - Alberta	546	794	1,288
Synthetic - Saskatchewan	64	70	70
Non-upgraded Bitumen	368	612	1,694
Oil Sands (net)	978	1,476	3,052
Own use	86	138	211
Oil Sands (gross)	1,064	1,614	3,263

Projections show gross natural gas production will decline modestly to some 4.7 TCF in 2020, as new production and non-conventional sources such as shale gas and coal-bed methane come to market²⁹ to offset conventional declines.

Table A.1.4 - Natural gas production

Billion Cubic Feet	2005	2010	2020
Supply ³⁰			
Gross Production	6,951	5,868	4,711
Own-use Consumption	689	648	493
Marketable Gas	6,262	5,221	4,219
Imports	346	828	828
Total Supply	6,608	6,049	5,047

²⁹ For the purposes of this document, shale gas development has been included under natural gas production. As more data and information on likely shale gas production trends become available, consideration will be given to modeling shale gas separately.

³⁰ For the most part, the oil and natural gas production projections reflect the views of the National Energy Board outlook for projects in these provinces. However, some adjustments have been made to reflect more recent market conditions. For example, the growth in shale gas production in British Columbia has been reduced.

The emissions outlook reflects plans by provincial and territorial utilities with respect to key electricity capacity expansions.

Taking into account these provincial utility expansion plans, plus additional units forecast to be built by Environment Canada's Energy, Emissions and Economy Model for Canada (E3MC) to meet growth in electricity demand, aggregate electricity generation is also expected to increase substantially, by about 13% from 2010 to 2020, with fuel mix changes as generation increases. Table A.1.5 describes, that the proportion of generation coming from wind power and other renewable sources is expected to increase from 2005 to 2020, starting at only about 0.3% in 2005 and reaching 6% of total generation by 2020. Importantly, though, the proportion of natural gas-fired generation is projected to double its 2005 levels.

Government actions, such as the introduction of the Electricity Performance Standard, will cause fuel switching in the overall electricity generating portfolio. As noted above, it is expected that natural gas-fired generation will double its 2005 levels by 2020, because of its appeal as a relatively cleaner source of power generation and a reliable means to cover peak loads. The lower natural gas price also makes it an affordable choice. Coal and petroleum coke generation fall from 18% of the generation in the Canadian portfolio in 2005 to 10% in 2020.

Table A.1.5 - Electricity generation by fuel

TWh	2005	2010	2020
Coal and Petroleum Coke	105	79	61
Refined Petroleum Products	12	5	5
Natural Gas	22	30	47
Hydro	329	321	362
Nuclear	87	86	87
Other Renewables	2	9	34
Total Generation	557	529	598

Emissions Factors

Table A.1.6 provides a rough estimate of carbon dioxide emitted per unit of energy consumed by fossil fuel type. These numbers are estimates, as specific emission factors can vary slightly by year, sector, and province.

Table A.1.6 - Mass of carbon dioxide emitted per quantity of energy for various fuels

Fuel name	CO₂ eq. emitted (g/10⁶ Joules)
Natural gas	49.7
Liquefied petroleum gas	61.0
Non-marketable natural gas	66.5
Propane	59.8
Aviation gasoline	69.6
Automobile gasoline	67.6
Kerosene	67.3
Light fuel oil	70.3
Heavy fuel oil	74.0
Tires/tire-derived fuel	80.8
Wood and wood waste	0 ³¹
Coal (bituminous)	88.1
Coal (subbituminous)	91.6
Coal (lignite)	92.4
Petroleum coke	86.4
Coal (anthracite)	97.6

³¹ While the emissions intensity of burning wood is 81.3 g/10⁶ Joules, biofuels such as wood can be considered carbon-neutral since carbon dioxide was absorbed from the atmosphere as the trees were growing.

Federal, Provincial and Territorial Measures

Since 2006, the Government of Canada has invested more than \$11.5 billion to reduce greenhouse gas emissions through investments in green infrastructure, energy efficiency, clean energy technologies and the production of cleaner energy and cleaner fuels. These include expenditures through the eco-action initiatives, clean energy fund, green infrastructure fund, transit pass program, marine shore power program, biofuels and bioproducts initiatives and programs, national vehicle scrapping program, and initiatives such as the National Renewable Diesel Demonstration Initiative – to name just a few.

In addition, regulations are being enacted to reduce emissions from key sources, and joint initiatives and investments have been undertaken with the provinces and territories to assist them in addressing their unique challenges and to facilitate coordinated approaches.

Table A.1.7 below identifies the major federal, provincial and territorial measures that are included in the Canada's Emissions Trends' reference case. It includes federal measures that have been implemented or announced in detail as of May 2012. Where program funding is set to end, the projections assume that the impacts of these programs, other than those embodied in consumer behaviour, cease when the approved funding terminates.

The analysis also includes existing provincial and territorial measures. Environment Canada monitors provincial/territorial initiatives, and strives to take them into account in its analysis and modeling (for the purposes of this report, provincial measures announced and fully implemented as of May 2012 have been included wherever possible).

While the emissions outlook's baseline scenario includes those existing measures that have been implemented or announced in specific detail, it does not take into account the impact of broader strategies or future measures within existing plans where significant details are still under development.

The federal government's climate change plan involves the development of measures to address emissions on a sector-by-sector basis, and some measures under development as part of this plan have not yet been included in the baseline scenario: for example, the government has committed to regulate the emissions of the Oil and Gas sector, but the details of the regulations are under development, so this measure is not yet included.

Similarly, broad provincial policy initiatives such as the B.C. Energy Plan, Manitoba's Beyond Kyoto plan, and under the Western Climate Initiative provincial announcements where the structure of the trading regime has yet to be released, are not taken into account in the baseline scenario.

Some of the key existing federal measures that have been taken into account in the baseline scenario include:

1. Performance Standard for Coal-Fired Electricity Generation – In June 2010, the Government announced its intention to regulate coal-fired electricity generation.

The regulations impose a performance standard on new coal-fired electricity generation units and those units that have reached the end of economic life. The new regulations, which are scheduled to take effect in 2015, will encourage electric utilities to transition towards lower- or non-emitting types of generation. The proposed regulations send a critical signal to industry in advance of expected significant capital stock turnover. By affecting capital investment decisions now, the regulations will help avoid a legacy of higher-emitting facilities being built. The gradual phase-out of old and dirty coal units is expected to significantly reduce emissions from the electricity generation sector and improve air quality for all Canadians.

2. Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations – In October 2010, the Government published its final *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*, which establish progressively stringent standards, harmonized with the U.S., for GHG emissions from new cars and light trucks for the 2011 to 2016 model years. The Government also published a *Notice of Intent* for “phase 2” of the regulations to develop more stringent GHG emissions standards for light-duty vehicles of model years 2017 to 2025.
3. Renewable Fuels Regulations – In 2006, as part of the Renewable Fuels Strategy, the Government of Canada announced its intention to regulate an annual average renewable fuel content of 5% in gasoline by 2010, and in a second phase, a 2% requirement for renewable content in diesel fuel and heating oil by 2011. The Strategy’s two regulatory requirements combined with provincial regulations will ensure a total volume of renewable fuel that will reduce annual greenhouse gas emissions by up to four Mt – about the equivalent of taking one million vehicles off the road.
4. Energy efficiency regulations, codes and standards for buildings and homes – The Government continues to update and strengthen energy efficiency standards for products under the *Energy Efficiency Act* and is working with provinces to update the National Energy Code for Buildings. These actions, combined with targeted incentive programs, have proven to be effective at reducing energy use and GHG emissions in this sector.

Table A.1.7 - GHG: measures reflected in projections (policies in place as of Spring 2012)

Provincial/Territorial Measures	Federal Measures
Alberta: - Alberta's Specified Gas Emitter's Regulation (SGER) B.C.: - BC Carbon Tax (update to \$30/tonne) - Energy Efficiency Programs ** - Low Carbon Fuel Standards (under WCI)^{32**} - Appliance Efficiency and Building Standards (under WCI)** Manitoba : - Low Carbon Fuel Standards (under WCI)** - Appliance Efficiency and Building Standards (under WCI)** Nova Scotia : - Nova Scotia's Cap on Electricity Sector GHG Emissions - Nova Scotia's 40% Renewable Requirement - Nova Scotia's Air Quality Regulations Ontario : - Ontario Coal Fired Phase Out - Ontario Feed-In-Tariff Energy Efficiency Standards - Ontario's Appliance Efficiency, Building Standards and Retrofits** - Energy Efficiency Programs ** - Low Carbon Fuel Standards (under WCI)** - Appliance Efficiency and Building Standards (under WCI)**	- 5% Renewable Fuel Content Regulation for Gasoline - 2% Renewable Fuel Content Regulation for Diesel fuel and Heating Oil - Light-Duty Vehicle Greenhouse Gas Emissions Regulations (2011-2016) - Electricity Performance Standard for Coal Fired Generation - Strengthened Energy Efficiency Standards - Eco-Initiatives: - o ecoENERGY for Renewable Power - o ecoENERGY Retrofit Initiative - o ecoENERGY for Buildings and Houses - o ecoENERGY for Industry - o ecoFreight Program - o ecoTechnology for Vehicles Program - o ecoENERGY for Fleets - o ecoMobility - o ecoENERGY for Renewable Heat - o ecoAUTO Rebate Program - o ecoENERGY for Personal Vehicles Initiative - o ecoENERGY for Biofuels Initiative - o ecoAGRICULTURE Biofuels Capital Initiative - o ecoENERGY Technology Initiative - Public Transit Tax Credit - Marine Shore Power Program (2007-2012)/Shore Power Technology for Ports Program (2012-2015) - Technology Development and Deployment - Energy efficiency regulation, codes and standards for buildings and homes

³² ** Western Climate Initiative (WCI) and revised/enhanced complementary policies are included in 2012 BAU; Apply to BC, MB, ON, QC.

Quebec : - Quebec's Cap and Trade - Quebec's Carbon Levy - Low Carbon Fuel Standards (under WCI)** - Appliance Efficiency and Building Standards (under WCI)*	
Additional Provincial Policies - Trends 2012	Additional Federal Policies - Trends 2012
Alberta: - Landfill gas regulations (BC, ON, AB) - Alberta Flaring and Venting emission control policy - o Alberta ERCB Directive 60 BC: - BC Clean Energy Act - Landfill gas regulations (BC, ON, AB) - BC Oil and Gas Commission's Flaring, Incinerating and Venting Reduction Guideline - Building Code Regulations and updates (BC, NS, NFLD, QC) - o Regulations requiring implementation of National Emission Standard CSA B415 (USA EPA standards) - Marine Shore Power Program Manitoba: - Venting and flaring requirements in permitting processes (MB, NFLD) New Brunswick - Renewable portfolio standard Newfoundland & Labrador: - Venting and flaring requirements in permitting processes (MB, NFLD) - Building Code Regulations and updates (BC, NS, NFLD, QC) - o Regulations requiring implementation of National Emission Standard CSA B415	- Passenger Automobile And Light Truck Greenhouse Gas Emission Regulations 2017-2025 - Heavy Duty Vehicle GHG Emission Regulations - BLIERS (may indirectly affect GHGs) - Marine spark-ignition engine and off-road recreational vehicle emission regulations - Regulations Amending Off-road Compression-Ignition Emission Regulations - National Action Plan on Ozone-depleting substances (ODS) and their Halocarbon Alternatives - Environmental Code of Practice for Elimination of Fluorocarbon Emissions from Refrigeration and Air Conditioning Systems

(USA EPA standards) Nova Scotia: - Building Code Regulations and updates (BC, NS, NFLD, QC) - o Regulations requiring implementation of National Emission Standard CSA B415 (USA EPA standards) Ontario: - Landfill gas regulations (BC, ON, AB) Saskatchewan: - Saskatchewan Energy and Resources Guide S-10/S-20 <i>"Gas Conservation Standards, and Upstream Flaring and Incineration Specifications"</i> Quebec: - Quebec regulation related to maximum sulphur content for heavy fuel oil - Building Code Regulations and updates(BC, NS, NFLD, QC) - o Regulations requiring implementation of National Emission Standard CSA B415 (USA EPA standards) - Quebec new standard for large heaters and boilers - Marine Shore Power Program	

Table A.1.8 - Announced 2020 GHG reduction targets of provincial governments (only announced and implemented measures under these targets are included in projections)	
Province/Territory	Target
British Columbia	33% below 2007
Alberta	50 Mt below BAU
Saskatchewan	20% below 2006
Manitoba	15% below 2005
Ontario	15% below 1990
Quebec	20% below 1990
New Brunswick	10% below 1990
Nova Scotia	10% below 1990
Newfoundland ³³	10% below 1990
Prince Edward Island ³⁴	10% below 1990

³³ Under the auspices of the Conference of New England Governors and Eastern Canadian Premiers (NEG-ECP) partnership, the four Atlantic provinces have committed to a regional goal of achieving 10% below 1990 levels by 2020.

³⁴ Prince Edward Island has not established its own official provincial emissions reduction target, so the common NEG-ECP target is applied for the purposes of this analysis.

Annex 2

Alternate Emissions Scenarios

Emissions projections are subject to uncertainty, and are most appropriately viewed as a range of plausible outcomes. Many of the events that shape emissions and energy markets cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Typically, these key uncertainties are addressed through alternative cases.

The sensitivity analysis presented here focuses on two key uncertainties:

- The growth of the economy
- The evolution of world oil prices and their impacts on macroeconomic growth and energy consumption

The emissions outcomes of these alternative cases are presented as stand-alone and in combinations in Table A.2.1. These alternative cases explore the interaction of energy markets and economic growth, and their impact on emissions, under a range of assumptions. As such, they show the resulting emissions relative to the baseline scenario excluding LULUCF (745 Mt).

The higher GDP case assumes stronger economic growth in the goods producing sector. By 2020, Canadian GDP in the high GDP case is some 34% higher than 2010 levels, compared with 26% higher in the baseline scenario.

By 2020, Canadian GDP in the low GDP case is some 17% higher than 2010 levels, compared with 26% higher in the baseline scenario.

In the baseline scenario, the world oil price is projected to grow from \$79/bbl (\$US) in 2010 to \$102/bbl (\$US) in 2020. A higher price scenario, in which 2020 prices are \$142/bbl (\$US), is used alone and in combination with different GDP growth assumptions. A low price scenario is also included where the world oil price remains fairly stable at \$72/bbl (\$US) after 2015.

Greenhouse gas emissions in the fast GDP growth scenario are about 11% higher in 2020 than 2010 levels. This compares with 8% higher emissions in the baseline scenario over the same period. As economic activity increases, there will unquestionably be a higher demand for energy and a corresponding increase in emissions. In contrast, emissions are expected to be much lower if the Canadian economy grows at a slower pace. When combined with high oil prices, emissions could be some 1.8% higher than 2010 levels by 2020. Expected growth of the economy is the primary driver of expected emission growth. Any variation in this path will lead to a different set of projections about expected future emissions.

Table A.2.1 - Sensitivity analysis - Change in GDP and/or world oil /natural gas prices

Cases	GHG emissions (in Mt CO ₂ e. - Excluding LULUCF)	
	2015	2020
Slow GDP	705	718
Fast GDP	733	771
Low World Oil Prices	729	741
High World Oil Prices	706	732
Slow GDP - Low World Oil Prices	714	714
Slow GDP - High World Oil Prices	692	705
Fast GDP - Low World Oil Prices	743	770
Fast GDP - High World Oil Prices	718	756
Baseline Scenario	719	745
Sensitivity Results	692 - 743	705 - 771

The growth in emissions is expected to slow down as the world price of oil increases since overall economic activity would decline as the price of oil rose. However, the increase in price drives higher production in the oil and gas sectors which generally offsets this effect. Emissions from the oil and gas sector in the high world oil price case rise by 69 Mt from 2010 to 2020; whereas they only rise by 50 Mt in the baseline scenario and by 34 Mt in the low price scenario.

The range in total projected emissions from all scenarios rises as we extend our projection further into the future. As a result of the assumptions made about the growth in Canadian GDP and the future world oil price, in 2020 the range is 66 Mt.

Under all scenarios over the forecast period, emissions are expected to grow the fastest in oil sands extraction and upgrading. Electricity generation and the conventional oil and gas sectors are projected to see an emissions decrease. Emission changes in the transportation sector show a deceleration from the long-term growth trend in all scenarios.

The oil sands sector displays the fastest growth in emissions, but it also displays the greatest range of uncertainty about future emissions depending on the assumptions used. Emissions could rise by as much as 82 Mt - or as little as 54 Mt - over the 2005 to 2020 period. The baseline scenario projects that oil sands emissions would increase by 73 Mt.

Annex 3

Methodology for Development of Emissions Scenarios

The scenarios developed to support Environment Canada's GHG emissions projections derive from a series of plausible assumptions regarding, among others, population and economic growth, prices, demand and supply of energy, and the evolution of energy efficiency technologies. The projections also assume no further government actions to address greenhouse gas emissions beyond those already in place or imminently pending as of May 2012.

The emissions projections presented in this report cannot be viewed as a forecast or prediction of emissions at a future date. Rather, this report presents a simple projection of the current structure and policy context into the future, without attempting to account for the inevitable but as yet unknown changes that will occur in government policy, energy supply, demand and technology, or domestic and international economic and political events.

The emissions projections have been developed in line with generally recognized best practices. They incorporate IPCC standards for estimating greenhouse gas emissions across different fuels and processes, rely on outside expert views and the most up-to-date data available for key drivers such as economic growth, energy prices, and energy demand and supply, and apply an internationally recognized energy and macroeconomic modelling framework in the estimation of emissions and economic interactions. Finally, the methodology used to develop the projections and underlying assumptions has been subject to peer review by leading external experts on economic modelling and greenhouse gas emissions projections, as well as vetted with key stakeholders.

The approach to developing Environment Canada's Emissions Trends involves three main features:

- Using the most up-to-date statistics on GHG emissions and energy use, and sourcing key assumptions from the best available public and private expert sources.
- Developing scenarios of emissions projections using a detailed, proven Energy, Emissions and Economy Model for Canada.
- Consulting with industry experts on results.

Up-to-date Data and Key Assumptions

Each year, Environment Canada updates its models using the most recent data available from Statistics Canada's Report on Energy Supply-Demand and Environment Canada's National Inventory Report. For these projections, the most recent historical

data available were for 2010. For the first time, emissions for Environment Canada's projections and historical data in the NIR are aligned based by economic sector.

In addition to the most recent historical information, the projections are based on expert-derived expectations of key drivers (e.g. world oil price). These assumptions are based on the latest energy and economic data, with key modeling assumptions aligned to Government of Canada views:

- National Energy Board views on energy prices and large scale energy projects
- Economic growth from Finance Canada's Budget 2012 Update of Economic and Fiscal Projections
- Statistics Canada's population growth projections
- Productivity growth projections

Even with the benefit of external expert assumptions, there is considerable uncertainty surrounding energy price and economic growth assumptions, particularly over the medium- to long-term. As such, a range of emissions is presented representing a series of sensitivity analyses. These cases were based on high and low GDP growth as well as high and low oil prices and productions levels.

Energy, Emissions and Economy Model for Canada

The projections presented in this chapter were generated from Environment Canada's Energy, Emissions and Economy Model for Canada, also known as E3MC.

E3MC has two components: Energy 2020, which incorporates Canada's energy supply and demand structure, and The Informetrica Model (TIM), a macroeconomic model of the Canadian economy.

- Energy 2020 is an integrated, multi-region, multi-sector North American model that simulates the supply, price and demand for all fuels. The model can determine energy output and prices for each sector, both in regulated and unregulated markets. It simulates how such factors as energy prices and government measures affect the choices that consumers and businesses make when they buy and use energy. The model's outputs include changes in energy use, energy prices, greenhouse gas emissions, investment costs and possible cost savings from measures, which are used to identify the direct effects stemming from greenhouse gas reduction measures. The resulting savings and investments from Energy 2020 are then used as inputs into TIM.
- The Informetrica Model is used to examine consumption, investment, production, and trade decisions in the whole economy. It captures the interaction among industries, as well as the implications for changes in producer prices, relative final prices, and income. It also factors in government fiscal balances, monetary flows, and interest and exchange rates. More specifically, TIM incorporates 133 industries at a provincial and territorial level. It also has an international component to

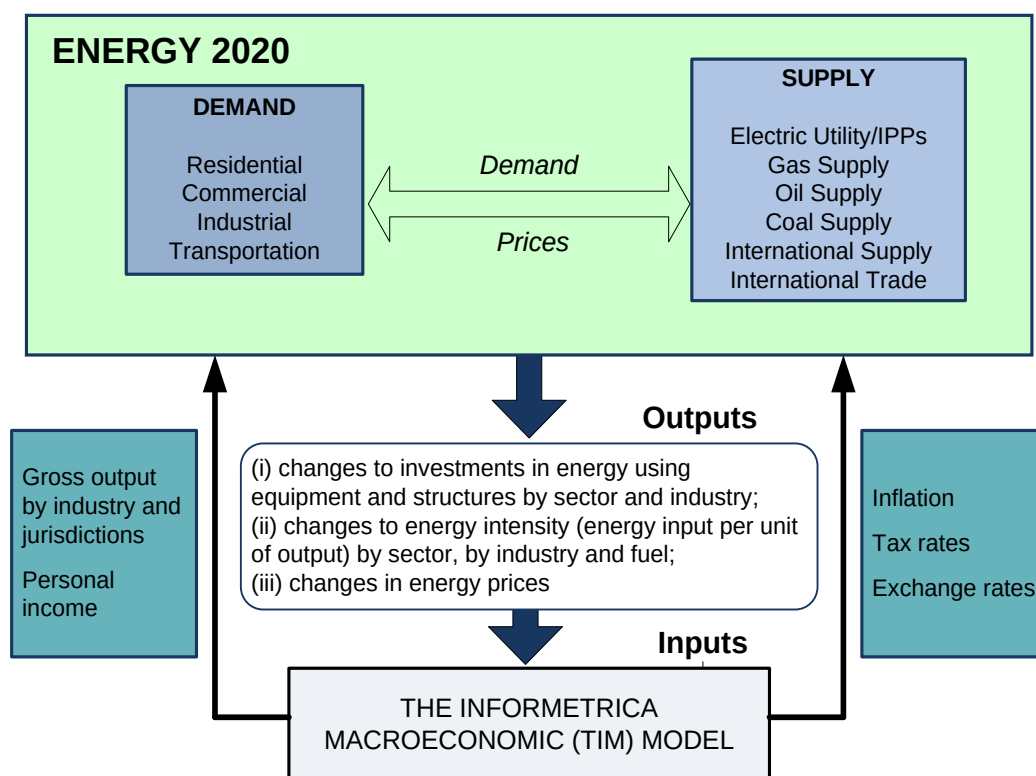
account for exports and imports, covering about 100 commodities. The model projects the direct impacts on the economy's final demand, output, employment, price formation, and sectoral income that result from various policy choices. These, in turn, permit an estimation of the effect of climate change policy and related impacts on the national economy.

E3MC develops projections using a market-based approach to energy analysis. For each fuel and consuming sector, the model balances energy supply and demand, accounting for economic competition among the various energy sources. This ensures consistent results among the sectors and regions. The model can be operated in a forecasting mode or an analytical mode. In forecasting mode, the model generates an annual energy and emissions outlook to 2050. In analytical mode, it assesses broad policy options, specific programs or regulations, new technologies or other assumptions.

The model's primary outputs are tables showing energy consumption, production and prices by fuel type, year and region. The model also identifies many of the key macroeconomic indicators (e.g., GDP or unemployment) and produces a coherent set of all greenhouse gas emissions (such as carbon dioxide, methane, and nitrous oxide) by sector and by province.

Figure A.3.1 shows the general structure of E3MC. The component modules of E3MC represent the individual supply, demand, and conversion sectors of domestic energy markets and also include the macroeconomic module. In general, the modules interact through values representing the prices of the energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Figure A3.1 - Energy, emissions and economy model for Canada



To develop this projection of energy use and related emissions, it was necessary to provide a view of the Canadian economy to 2020. The level and composition of energy supply and demand, and the resulting greenhouse gas emissions, are determined based on many assumptions that influence the overall size and growth rate of the economy.

Treatment of Interaction Effects

Estimates of the net impact of government measures incorporated in the modelling scenarios need to take into account major interaction and behavioural affects. The analytical approach permitted by E3MC addresses these key modeling challenges, namely additionality, free ridership, rebound effects, and policy-interaction effects.

- **Additionality.** This issue relates to the question of what would have happened without the initiative in question. Problems of additionality arise when the stated emissions reductions do not reflect the difference in emissions between equivalent scenarios with and without the initiative in question. This will be the case if stated emissions reductions from an initiative have already been included in the reference case – emissions reductions will effectively be double-counted in the absence of appropriate

adjustments. The E3MC model controls for additionality by basing its structure on incremental or marginal decision-making. The E3MC model assumes a specific energy efficiency or emission intensity profile at the sector and end-use point (e.g., space heating, lighting, or auxiliary power). Under the E3MC modeling philosophy, if the initiative in question were to increase the efficiency of a furnace, only the efficiency of a new furnace would be changed. The efficiency of older furnaces would not change unless those furnaces are retired and replaced with higher efficiency ones. As such, any change in the model is incremental to what is reflected in the business-as-usual assumptions.

- *Free ridership.* A related problem, free ridership, arises when stated reductions include the results of behaviour that would happen regardless of the policy. This can occur when subsidies are paid to all purchasers of an item (e.g., a high efficiency furnace), regardless of whether they purchased the item because of the subsidy. Those who would have purchased the product regardless are termed free riders. In the E3MC model, the behaviour of free riders has already been accounted for in the reference case. Thus their emissions are not counted toward the impact of the policy. Instead, the E3MC model counts only the incremental take-up of the emissions-reducing technology.
- *The rebound effect.* This describes the increased use of a more efficient product resulting from the implied decrease in the price of its use. For example, a more efficient car is cheaper to drive and so people may drive more. Emissions reductions will generally be overestimated by between 5% and 20% unless estimates account for increased consumption because of the rebound effect. Within the model, we have mechanisms for fuel choice, process efficiency, device efficiency, short-term budget constraints, and cogeneration, which all react to changes in energy and emissions costs in different timeframes.³⁵ All these structures work to simulate the rebound effect – in the example above, the impact of extra kilometres that may be driven as a result of improved fuel efficiency are automatically netted out of the associated emissions reduction estimates.
- *Policy interaction effects.* This describes impacts on the overall effectiveness of Canada's emissions-reduction measures when they interact with each other. A policy package containing more than one measure or policy would ideally take into account this impact to understand the true contribution that the policy package is making (in this case, to emission reductions).

E3MC is a comprehensive and integrated model focusing on the interactions between sectors and policies. In the demand sectors, the fuel choice, process efficiency, device

³⁵ A shift in energy prices will cause cogeneration to shift in the short to medium term, device efficiency to adjust over the short to mid-term, process efficiency to adjust in the mid-term, and fuel choice to react in the mid- to long-term. The actual adjustment times depend on the particular sector.

efficiency, and level of self-generation are all integrally combined in a consistent manner. The model has detailed equations to ensure that all the interactions between these structures are simulated with no loss of energy or efficiency. For example, the electric generation sector responds to the demand for electricity from the energy demand sectors, so any policy to reduce electricity demand in the consumer sectors will impact the electricity generation sector. The model accounts for emissions in the electricity generation sector as well as for emissions in the consumer demand sectors. As the electricity sector reduces its emissions intensity, policies designed to reduce electricity demand in the consumer sectors will cause less of an emissions reduction. The natural gas and oil supply sectors similarly respond to the demands from the consumer sectors, including the demands for refined petroleum products for transportation. The model also simulates the export of products by supply sectors.

Taken as a whole, the E3MC model provides a detailed representation of technologies that produce goods and services throughout the economy and can simulate, in a realistic way, capital stock turnover and choices among technologies. The model also includes a representation of equilibrium feedbacks, such that supply and demand for goods and services adjust to reflect policy. Given its comprehensiveness, E3MC covers all the greenhouse gas emissions sources, including those unrelated to energy use.

Simulation of capital stock turnover

As a technology vintage model, E3MC 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-kilometre traveled. In each period, capital stocks are retired according to an age-dependent function (although the retrofitting of unretired stocks is possible, if warranted by changing economic conditions). Demand for new stocks grows or declines depending on the initial exogenous forecast of economic output (i.e., a forecast that is external to the model and not explained by it) and the subsequent interplay of energy supply-demand with the macroeconomic module. A model simulation iterates between energy supply-demand and the macroeconomic module until there is a convergence. The global convergence criterion is set at 0.1% between iterations. This convergence procedure is repeated for each year over the simulation period.

The E3MC model simulates the competition of technologies at each energy service node in the economy based on a comparison of their cost and some technology-specific controls, such as a maximum market share limit in cases where a technology is constrained by physical, technical, or regulatory means from capturing all of a market. The technology choice simulation reflects the financial costs as well as the consumer and business preferences, revealed by real-world technology acquisition behaviour.

Model Limitations

While E3MC is a sophisticated analytical tool, no model can fully capture the complicated interactions associated with given policy measures between and within markets or between firms and consumers. Unlike computable general equilibrium models, however, the E3MC model does not fully equilibrate government budgets and the markets for employment and investment. That is, the modeling results reflect rigidities such as unemployment and government surpluses and deficits. Furthermore, the model, as used by Environment Canada, does not generate changes in nominal interest rates and exchange rates, as would occur under a monetary policy response to a major economic event.

www.ec.gc.ca

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TTY: 819-994-0736

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Available NGV Aftermarket Conversion Systems

The information contained in this document covers aftermarket conversion systems that consumers and businesses may purchase in order to modify new or used vehicles so that they can operate on natural gas. Some of these systems may be ordered directly through automotive dealerships when placing an order for a new vehicle. However, all of the systems listed here are aftermarket from the standpoint that they are offered as modifications to original equipment manufacturer (OEM) gasoline or diesel fueled vehicles.

The information is organized by certified or approved light-duty and heavy-duty chassis vehicles, as well as by certified or approved heavy-duty engines. The individual sheets are further organized by OEM (e.g., Chrysler, Ford, or GM), model year, and engine size, so that persons interested in a conversion system for a particular vehicle may quickly locate it. All of the systems listed have been either certified or approved by the U.S. Environmental Protection Agency (EPA) or the California Air Resources Board (CARB). Please do not contact NGVAmerica regarding the availability of aftermarket systems. NGVAmerica does not sell conversion systems or provide any services related to the installation of such systems.

Please review the listings of available systems and also the websites of the companies who offer them. All of these companies are dealing with a large number of inquiries and a significant demand for NGVs, so please review all available materials before making inquiries about particular vehicles, systems, or engines.

For future updates of this document, visit the NGVAmerica website [here](#).

List of abbreviations:

EPA Cert.....U.S. EPA Certified
 CARB.....California Air Resources Board
 Int Appr.....Intermediate Approval by U.S. EPA
 OUL.....Outside Useful Life

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Chrysler	2013	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0130PKA	DNATJ03.6VPB-008-R01	DNATR0130PK1	DNATJ03.6VPB	EPA Cert
Chrysler	2013	3.6	NatGasCar: C/V, Grand Caravan, Routan, Town & Country	CNG	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0150RKA	DNATJ03.6VPB-009-R01	DNATR0150RK1	DNATJ03.6VPB	EPA Cert
Chrysler	2013	3.6	NatGasCar: Journey	CNG	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0153PKA	DNATJ03.6VPB-010	DNATR0153PK1	DNATJ03.6VPB	EPA Cert
Chrysler	2013	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0130PKA	DNATJ03.6VPA-005-R01	DNATR0130PKA	DNATJ03.6VPA	EPA Cert
Chrysler	2013	3.6	NatGasCar: Journey	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0153PKA	DNATJ03.6VPA-006-R01	DNATR0153PKA	DNATJ03.6VPA	EPA Cert
Chrysler	2013	3.6	NatGasCar: C/V, Grand Caravan, Routan, Town & Country	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DCRXJ03.6VPA	DCRXR0150RKA	DNATJ03.6VPA-007-R01	DNATR0150RKA	DNATJ03.6VPA	EPA Cert
Chrysler	2013	4.7	NatGasCar: 1500 2WD, 1500 4WD	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DCRXT04.7UPA	DCRXR0190RKA	DNATT04.7UPA-003-R01	DNATR0190RKA	DNATT04.7UPA	EPA Cert
Chrysler	2013	4.7	NatGasCar: 1500 2WD, 1500 4WD	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DCRXT04.7UPA	DCRXR0225RKA	DNATT04.7UPA-004-R01	DNATR0225RKA	DNATT04.7UPA	EPA Cert
Chrysler	2012	3.6	NatGasCar: Grand Caravan, Ram C/V, Routan, Town & Country	CNG	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0150RMA	CNATJ03.6VPB-014	CNATR0150RM1	CNATJ03.6VPB	EPA Cert
Chrysler	2012	3.6	NatGasCar: Journey	CNG	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0153PKA	CNATJ03.6VPB-015-R01	CNATR0153PM1	CNATJ03.6VPB	EPA Cert
Chrysler	2012	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0130PKA	CNATJ03.6VPB-016-R01	CNATR0130PM1	CNATJ03.6VPB	EPA Cert
Chrysler	2012	3.6	NatGasCar: Grand Caravan, Ram C/V, Routan, Town & Country	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0150RMA	CNATJ03.6VPA-011	CNATR0150RMA	CNATJ03.6VPA	EPA Cert
Chrysler	2012	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0130PKA	CNATJ03.6VPA-012-R01	CNATR0130PKA	CNATJ03.6VPA	EPA Cert
Chrysler	2012	3.6	NatGasCar: Journey	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CCRXJ03.6VPA	CCRXR0153PKA	CNATJ03.6VPA-013-R01	CNATR0153PKA	CNATJ03.6VPA	EPA Cert
Chrysler	2012	4.7	NatGasCar: Ram 1500 2WD, Ram 1500 4WD	CNG	Gasoline/E85	Nat Gas Car LLC	CCRXT04.7UPA	CCRXR0190RKA	CNATT04.7UPB-006	CNATR0190RK1	CNATT04.7UPB	EPA Cert
Chrysler	2012	4.7	NatGasCar: Ram 1500 2WD, Ram 1500 4WD	CNG	Gasoline/E85	Nat Gas Car LLC	CCRXT04.7UPA	CCRXR0225RKA	CNATT04.7UPB-007	CNATR0225RK1	CNATT04.7UPB	EPA Cert
Chrysler	2012	4.7	NatGasCar: Ram 1500 2WD, Ram 1500 4WD	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CCRXT04.7UPA	CCRXR0190RKA	CNATT04.7UPA-004	CNATR0190RKA	CNATT04.7UPA	EPA Cert
Chrysler	2012	4.7	NatGasCar: Ram 1500 2WD, Ram 1500 4WD	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CCRXT04.7UPA	CCRXR0225RKA	CNATT04.7UPA-005	CNATR0225RKA	CNATT04.7UPA	EPA Cert
Chrysler	2011	3.6	NatGasCar: Grand Caravan, Routan, Town & Country	CNG	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0150RKA	CNATJ03.6UPB-001	CNATR0150RK1	CNATJ03.6UPB	EPA Cert
Chrysler	2011	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0130PKA	CNATJ03.6UPB-002	CNATR0130PK1	CNATJ03.6UPB	EPA Cert
Chrysler	2011	3.6	NatGasCar: Journey	CNG	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0153PKA	CNATJ03.6UPB-003	CNATR0153PK1	CNATJ03.6UPB	EPA Cert
Chrysler	2011	3.6	NatGasCar: 200, 200 Convertible, Avenger	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0130PKA	CNATJ03.6UPA-008	CNATR0130PKA	CNATJ03.6UPA	EPA Cert
Chrysler	2011	3.6	NatGasCar: Grand Caravan, Routan, Town & Country	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0150RKA	CNATJ03.6UPA-009	CNATR0150RKA	CNATJ03.6UPA	EPA Cert
Chrysler	2011	3.6	NatGasCar: Journey	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	BCRXJ03.6UPA	BCRXR0153PKA	CNATJ03.6UPA-010	CNATR0153PKA	CNATJ03.6UPA	EPA Cert
Chrysler	2011	4.7	01: Dodge Dakota, Dodge Ram 1500, Mitsubishi Raider	CNG	Gasoline	Nat Gas Car LLC	BCRXT04.7UPA	BCRXR0180RKA; BCRXR0190RKA; BCRXR0225RKA	BNATT04.7UPF-004	BNATR0180RKA	BNATT04.7UPF	EPA Cert
Chrysler	2011	4.7	01: Dodge Dakota, Dodge Ram 1500, Mitsubishi Raider	CNG or gasoline	Gasoline	Nat Gas Car LLC	BCRXT04.7UPA	BCRXR0180RKA; BCRXR0190RKA; BCRXR0225RKA	BNATT04.7UPE-003	BNATR0180RKA	BNATT04.7UPE	EPA Cert

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Chrysler	2010	3.3	TOWN AND COUNTRY FWD, GRAND CARAVAN FWD	CNG or gasoline/E85	Gasoline/E85	Natgasgar LLC	ACRXT03.3UPA	ACRXXR0150RKA		DNATR0150RKA	DNATT03.3UPA	Int Appr
Chrysler	2010	4.7	01: Dodge Dakota, Dodge Ram 1500, Mitsubishi Raider	CNG	Gasoline	Nat Gas Car LLC	ACRXT04.7UPC	ACRXXR0180RKA; ACRXXR0190RKA; ACRXXR0225RKA	BNATT04.7UPD-002	BNATR0180RKA	BNATT04.7UPD	EPA Cert
Chrysler	2010	4.7	01: Dodge Dakota, Dodge Ram 1500, Mitsubishi Raider	CNG or gasoline	Gasoline	Nat Gas Car LLC	ACRXT04.7UPC	ACRXXR0180RKA; ACRXXR0190RKA; ACRXXR0225RKA	BNATT04.7UPB-001	BNATR0180RKA	BNATT04.7UPB	EPA Cert
Chrysler	2009	3.7	JEEP LIBERTY 2WD, JEEP LIBERTY 4WD, DODGE NITRO 2WD, DODGE NITRO 4WD	CNG or gasoline	Gasoline	Natgasgar LLC	9CRXT03.74P0	9CRXR0150PK0		CNATR0150PK0	CNATT03.74P0	Int Appr
Chrysler	2009	3.7	JEEP GRAND CHEROKEE 2WD, JEEP GRAND CHEROKEE 4WD	CNG or gasoline	Gasoline	Natgasgar LLC	9CRXT03.74P0	9CRXR0180PK0		CNATR0180PK0	CNATT03.74P0	Int Appr
Chrysler	2009	3.7	JEEP COMMANDER 2WD, JEEP COMMANDER 4WD	CNG or gasoline	Gasoline	Natgasgar LLC	9CRXT03.74P0	9CRXR0180RKO		CNATR0180RKO	CNATT03.74P0	Int Appr
Ford	2014	6.2	F250 Pickup 2WD, F250 Pickup 4WD, F350 Pickup 2WD, F350 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXR0250NBS	EAECT06.27HA-004	EAECR0250NB1	EAECT06.27HA	EPA Cert
Ford	2014	6.2	F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD Bed Delete, F350 Pickup 2WD, F350 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXF0250NBS	EAECT06.27HA-005	EAECF0250NB1	EAECT06.27HA	EPA Cert
Ford	2014	6.2	F350 Incomplete 2WD, F350 Incomplete 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXF0265NAS	EAECT06.27HA-006	EAECF0265NA1	EAECT06.27HA	EPA Cert
Ford	2014	6.2	F250 Pickup 2WD, F250 Pickup 4WD, F350 Pickup 2WD, F350 Pickup 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXR0250NBS	EAECT06.27HL-001	EAECR0250NBS	EAECT06.27HL	EPA Cert
Ford	2014	6.2	F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD Bed Delete, F350 Pickup 2WD, F350 Pickup 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXF0250NBS	EAECT06.27HL-002	EAECR0250NBS	EAECT06.27HL	EPA Cert
Ford	2014	6.2	F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	EFMXT06.27HL	EFMXF0265NAS	EAECT06.27HL-003	EAECF0265NAS	EAECT06.27HL	EPA Cert
Ford	2014	6.2	Ford Motor Company: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline	Gasoline/E85	Westport Power Inc.	EFMXT06.27HL	EFMXR0250NBS	EWSP06.2CNG-001-R01	EWSPR0250NBS	EWSP06.2CNG	EPA Cert
Ford	2014	6.2	Ford Motor Company: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 2WD, F350 4WD Bed Delete	CNG or gasoline	Gasoline/E85	Westport Power Inc.	EFMXT06.27HL	EFMXF0250NBS	EWSP06.2CNG-002-R01	EWSPF0250NBS	EWSP06.2CNG	EPA Cert
Ford	2014	6.2	Ford Motor Company: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline	Gasoline/E85	Westport Power Inc.	EFMXT06.27HL	EFMXF0265NAS	EWSP06.2CNG-003-R01	EWSPF0265NAS	EWSP06.2CNG	EPA Cert
Ford	2013	2.0	Altech-Eco Corporation: Transit Connect Van, Transit Connect Wagon FWD	CNG	Gasoline	Altech-Eco Corporation	DFMXT02.01DW	DFMXR0125NBB	DAECT02.01DA-001-R01	DAECR0125NB1	DAECT02.01DA	EPA Cert
Ford	2013	2.0	Altech-Eco Corporation: Transit Connect Van, Transit Connect Wagon FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	DFMXT02.01DW	DFMXR0125NBB	DAECT02.01DW-002-R01	DAECR0125NB1	DAECT02.01DW	EPA Cert
Ford	2013	2.0	BAF Technologies: Ford Transit Connect	CNG	Gasoline	BAF Technologies	DFMXT02.01DW	DFMXR0125NBB	DBAFT02.01DW-003-R01	DBAFR0000001	DBAFT02.01DW	EPA Cert

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Ford	2013	2.0	BAF_Bifuel: Transit Connect	CNG or gasoline	Gasoline	BAF Technologies	DFMXT02.01DW	DFMXR0125NBB	DBAFT02.0EDF-010-R01	DBAFR0125NBB	DBAFT02.0EDF	EPA Cert
Ford	2013	3.7	Altech-Eco Corporation: F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SFE PICKUP 2WD	CNG	Gasoline/E85	Altech-Eco Corporation	DFMXT03.73DP	DFMXR0265NBV	DAECT03.73DA-011-R01	DAECR0265NB2	DAECT03.73DA	EPA Cert
Ford	2013	3.7	Altech-Eco Corporation: F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SFE PICKUP 2WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	DFMXT03.73DP	DFMXR0265NBV	DAECT03.73DP-010-R01	DAECR0265NBV	DAECT03.73DP	EPA Cert
Ford	2013	3.7	BAF Technologies: F150	CNG	Gasoline/E85	BAF Technologies	DFMXT03.73DP	DFMXR0265NBV	DBAFT03.73DP-002-R01	DBAFR0000001	DBAFT03.73DP	EPA Cert
Ford	2013	3.7	Lincoln MKT Livery, Lincoln MKT FWD, Lincoln MKS FWD	CNG	Gasoline	BAF Technologies			EO-A-364-0044	DBAFR0000001	DBAFV03.7CE8	CARB
Ford	2013	5.0	NatGasCar: F150 PICKUP 2WD, F150 PICKUP 4WD	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	DFMXT05.03D7	DFMXR0265NBV	DNATT05.03D7-011-R01	DNATR0265NBV	DNATT05.03D7	EPA Cert
Ford	2013	5.0	Ford: F150 truck 2WD, F150 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT05.03D7; CFMXT05.03DD	CFMXR0265NBV	EPRT05.03D3-002-R01	EPFR0265NBV	EPRT05.03D3	EPA Cert
Ford	2013	5.0	Ford: F150 truck 2WD, F150 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT05.03D7	DFMXR0265NBV	EPRT05.03D5-001-R01	EPFR0265NBV	EPRT05.03D5	EPA Cert
Ford	2013	5.4	Altech-Eco Corporation: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG	Gasoline/E85	Altech-Eco Corporation	DFMXT05.45HK; DFMXT05.45HL	DFMXR0265NBD	DAECT05.45HA-003-R01	DAECR0265NB1	DAECT05.45HA	EPA Cert
Ford	2013	5.4	BAF Technologies: E350 Cutaway	CNG	Gasoline	BAF Technologies	DFMXE05.4AFD	DFMXR0265NBD	DBAFD05.4AFD-009-R01, EO A-364-0041	DBAFR0000001	DBAFD05.4AFD, DBAFD05.4CFD	EPA Cert, CARB
Ford	2013	5.4	BAF Technologies: Ford E-Series Van	CNG	Gasoline/E85	BAF Technologies	DFMXT05.45HK	DFMXR0265NBD	DBAFT05.45HK-004	DBAFR0000001	DBAFT05.45HK	EPA Cert
Ford	2013	5.4	BAF Technologies: Ford E350 Club Wagon, E350 Van, E350 Cutaway, E250 Van, E150 Club Wagon, E 150 Van	CNG	Gasoline	BAF Technologies		DBAFR0000001	EO A-364-0042		DBAFT05.4CHK	CARB
Ford	2013	5.4	E350 Cutaway, E350 Wagon, E350 Van, E250 Van, E150 Wagon, E150 Van	CNG	Gasoline	Landi Renzo USA Corporation			EO A-400-0007	DLDRR00000A11	DLDR05.4A11	CARB
Ford	2013	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 Pickup 2WD, F350 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXR0250NBS	DAECT06.27HA-007-R01	DAECR0250NB3	DAECT06.27HA	EPA Cert
Ford	2013	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 2WD Bed Delete, F350 Pickup 2WD, F350 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXF0250NBS	DAECT06.27HA-008-R01	DAECF0250NB3	DAECT06.27HA	EPA Cert
Ford	2013	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXF0265NAS	DAECT06.27HA-009	DAECF0265NA1	DAECT06.27HA	EPA Cert
Ford	2013	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 Pickup 2WD, F350 Pickup 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXR0250NBS	DAECT06.27HL-004-R01	DAECR0250NB2	DAECT06.27HL	EPA Cert

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Ford	2013	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD Bed Delete, F350 Pickup 2WD, F350 Pickup 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXF0250NBS	DAECT06.27HL-005-R01	DAECF0250NB2	DAECT06.27HL	EPA Cert
Ford	2013	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline	Gasoline/E85	Altech-Eco Corporation	DFMXT06.27HL	DFMXF0265NAS	DAECT06.27HL-006-R01	DAECF0265NAS	DAECT06.27HL	EPA Cert
Ford	2013	6.2	BAF Technologies: Ford F250/350	CNG	Gasoline/E85	BAF Technologies	DFMXT06.27HL	DFMXR0250NBS; DFMXF0250NBS; DFMXF0265NAS	DBAFT06.27HL-001-R02	DBAFR0000001	DBAFT06.27HL	EPA Cert
Ford	2013	6.2	BAF Technologies: Ford F350 Pickup, F350 Cab Chassis, F350 Bed Delete, F250 Pickup, F250 Bed Delete, F350 Pickup DRW, F350 Pickup, F350 Bed Delete DRW, F350 Cab Chassis, F350 Bed Delete	CNG	Gasoline/E85	BAF Technologies			EO A-364-0043	DBAFR0000001	DBAFT06.2CHL	CARB
Ford	2013	6.2	IMPCO Automotive - Ford: Ford F250 2WD Bed Delete, Ford F250 4WD Bed Delete, Ford F250 PICKUP 2WD, Ford F250 PICKUP 4WD, Ford F350 2WD, Ford F350 2WD Bed Delete, Ford F350 4WD, Ford F350 4WD Bed Delete, Ford F350 INCOMPLETE 2WD, Ford F350 INCOMPLETE 4WD	CNG	Gasoline/E85	IMPCO Technologies, Inc.	DFMXT06.27HL	DFMXF0250NBS; DFMXF0265GAS; DFMXR0250NBS	DZ9XT06.2DCE-016	DZ9XR0000DCE	DZ9XT06.2DCE	EPA Cert
Ford	2013	6.2	IMPCO Automotive - Ford: Ford F250 2WD Bed Delete, Ford F250 4WD Bed Delete, Ford F350 2WD, Ford F350 2WD Bed Delete, Ford F350 4WD, Ford F350 4WD Bed Delete	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DFMXT06.27HL	DFMXF0250NBS	DZ9XT06.2BCE-013-R01	DZ9XF0250B8CA	DZ9XT06.2BCE	EPA Cert
Ford	2013	6.2	IMPCO Automotive - Ford: Ford F250 PICKUP 2WD, Ford F250 PICKUP 4WD, Ford F350 2WD, Ford F350 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DFMXT06.27HL	DFMXR0250NBS	DZ9XT06.2BCE-015-R01	DZ9XR0250B8CC	DZ9XT06.2BCE	EPA Cert
Ford	2013	6.2	IMPCO Automotive - Ford: Ford F350 INCOMPLETE 2WD, Ford F350 INCOMPLETE 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DFMXT06.27HL	DFMXF0265GAS	DZ9XT06.2BCE-014-R01	DZ9XF0265B8CB	DZ9XT06.2BCE	EPA Cert
Ford	2013	6.2	Landi Renzo USA: F250 PICKUP 2WD, F350 2WD, F350 INCOMPLETE 2WD, F350 PICKUP 4WD	CNG or gasoline	Gasoline/E85	Landi Renzo USA Corporation	DFMXT06.27HL	DFMXR0250NBS	DLDRT06.2C20-001-R01	DLDRR0250NBS	DLDRT06.2C20	EPA Cert
Ford	2013	6.2	Landi Renzo USA: F350 CAB CHASSIS 2WD, F350 CAB CHASSIS 4WD	CNG or gasoline	Gasoline/E85	Landi Renzo USA Corporation	DFMXT06.27HL	DFMXF0265NAS	DLDRT06.2C20-002-R01	DLDRF0265NAS	DLDRT06.2C20	EPA Cert

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Ford	2013	6.2	Landi Renzo USA: F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD, F350 2WD BED DELETE, F350 4WD BED DELETE, F350 INCOMPLETE 2WD	CNG or gasoline	Gasoline/E85	Landi Renzo USA Corporation	DFMXT06.27HL	DFMXF0250NBS	DLDR06.2C20-003	DLDR06.250NBS	DLDR06.2C20	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXR0250NBS	EPRT06.2HL1-003-R01	EPRT06.250NBS	EPRT06.2HL1	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXF0250NBS	EPRT06.2HL1-004-R01	EPRT06.250NBS	EPRT06.2HL1	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXF0265GAS	EPRT06.2HL1-005-R01	EPRT06.265GAS	EPRT06.2HL1	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXR0250NBS	EPRT06.2HL2-006-R01	EPRT06.250NBS	EPRT06.2HL2	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXF0250NBS	EPRT06.2HL2-007-R01	EPRT06.250NBS	EPRT06.2HL2	EPA Cert
Ford	2013	6.2	Ford: F250/350 truck 2WD, F250/350 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	DFMXT06.27HL	DFMXF0265GAS	EPRT06.2HL2-008-R01	EPRT06.265GAS	EPRT06.2HL2	EPA Cert
Ford	2013	6.2	Ford: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline	Gasoline/E85	Westport Light Duty Inc.	DFMXT06.27HL	DFMXR0250NBS	DJNPT06.2CNG-001-R01	DJNPR0250NBS	DJNPT06.2CNG	EPA Cert
Ford	2013	6.2	Ford: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 2WD, F350 2WD Bed Delete, F350 4WD, F350 4WD Bed Delete	CNG or gasoline	Gasoline/E85	Westport Light Duty Inc.	DFMXT06.27HL	DFMXF0250NBS	DJNPT06.2CNG-002-R01	DJNPF0250NBS	DJNPT06.2CNG	EPA Cert
Ford	2013	6.2	Ford: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline	Gasoline/E85	Westport Light Duty Inc.	DFMXT06.27HL	DFMXF0265NAS	DJNPT06.2CNG-003	DJNPF0265NAS	DJNPT06.2CNG	EPA Cert
Ford	2013	6.2, 5.4	BAF_Bifuel: E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	DFMXT05.45HK	DFMXR0265NBD	DBAFT06.254B-005-R01	DBAFR0265NBD	DBAFT06.254B	EPA Cert
Ford	2013	6.2, 5.4	BAF_Bifuel: F250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	DFMXT06.27HL	DFMXR0250NBS	DBAFT06.254B-006-R01	DBAFR0250NBS	DBAFT06.254B	EPA Cert
Ford	2013	6.2, 5.4	BAF_Bifuel: F250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	DFMXT06.27HL	DFMXF0250NBS	DBAFT06.254B-007-R01	DBAFF0250NBS	DBAFT06.254B	EPA Cert
Ford	2013	6.2, 5.4	BAF_Bifuel: F250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	DFMXT06.27HL	DFMXF0265NAS	DBAFT06.254B-008	DBAFF0265NAS	DBAFT06.254B	EPA Cert
Ford	2012	2.0	Altech-Eco Corporation: Transit Connect Van, Transit Connect Wagon FWD	CNG	Gasoline	Altech-Eco Corporation	CFMXT02.01DW	CFMXR0125NBB	CAECT02.01DB-019	CAECR0125NBB	CAECT02.01DB	EPA Cert
Ford	2012	2.0	Altech-Eco Corporation: Transit Connect Van, Transit Connect Wagon FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	CFMXT02.01DW	CFMXR0125NBB	CAECT02.01DW-020	CAECR0125NBB	CAECT02.01DW	EPA Cert
Ford	2012	2.0	BAF Technologies: Ford Transit Connect	CNG	Gasoline	BAF Technologies	CFMXT02.01DW	CFMXR0125NBB	CBAFT02.01DW-002	CBAFR0000001	CBAFT02.01DW	EPA Cert, CARB
Ford	2012	2.0	BAF_Bifuel: Transit Connect	CNG or gasoline	Gasoline	BAF Technologies	CFMXT02.0EDF	CFMXR0125NBB	CBAFT02.0EDF-010	CBAFR0125NBB	CBAFT02.0EDF	EPA Cert
Ford	2012	2.0	IA Dedicated CNG - Ford: Ford Transit Connect	CNG	Gasoline	IMPICO Technologies, Inc.	CFMXT02.01DW	CFMXR0125NBB	CZ9XT02.0DCE-026	CZ9XR0000N1E	CZ9XT02.0DCE	EPA Cert
Ford	2012	2.0	Ford Transit Connect Van, Transit Connect Wagon	CNG	Gasoline	IMPICO Technologies, Inc.	CFMXT02.01DW	CFMXR0125NBB	EO A-328-00054	CZ9XR0000E1A	CZ9XT02.0DCA	CARB
Ford	2012	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD	CNG	Gasoline	Altech-Eco Corporation	CFMXT02.51EN	CFMXR0125NBV	CAECV02.5VEA-022-R01	CAECR0125NB1	CAECV02.5VEA	EPA Cert
Ford	2012	2.5	Altech-Eco Corporation: Fusion FWD, Fusion S FWD	CNG	Gasoline	Altech-Eco Corporation	CFMXT02.5VEN	CFMXR0155GAV	CAECV02.5VEA-024-R01	CAECR0155GA1	CAECV02.5VEA	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2012	2.5	Altech-Eco Corporation: Fusion FWD, Fusion S FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	CFMXV02.5VEN	CFMXR0155GAV	CAECV02.5VEN-021-R01	CAECR0155GAV	CAECV02.5VEN	EPA Cert
Ford	2012	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	CFMXT02.51EN	CFMXR0125NBV	CAECV02.5VEN-023-R01	CAECR0125NBV	CAECV02.5VEN	EPA Cert
Ford	2012	2.5	IA Dedicated CNG - Ford: Ford Escape AWD, Ford Escape FWD	CNG	Gasoline	IMPACO Technologies, Inc.	CFMXT02.51EN	CFMXR0125NBV	CZ9XT02.5DCE-020-R01	CZ9XR0000N2E	CZ9XT02.5DCE	EPA Cert
Ford	2012	2.5	Ford Escape AWD, Ford Escape FWD	CNG	Gasoline	IMPACO Technologies, Inc.	CFMXT02.51EN	CFMXR0125NBV	CZ9XT02.5DCE-020-R01, EO A-328-0056		CZ9XT02.5DCE, CZ9XT02.5DCA	EPA Cert, CARB
Ford	2012	5.0	AEC: F150 Pickup 2WD Altech-Eco Corporation: F150 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT05.03DD	CFMXR0265NBV	CAECT05.03DA-014	CAECR0265NB1	CAECT05.03DA	EPA Cert
Ford	2012	5.0	AEC: F150 Pickup 2WD Altech-Eco Corporation: F150 Pickup 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	CFMXT05.03DD	CFMXR0265NBV	CAECT05.03DD-013	CAECR0265NBV	CAECT05.03DD	EPA Cert
Ford	2012	5.0	IA Bi-Fuel CNG - Ford: F150 Pickup 2WD, F150 Pickup 4WD	CNG or gasoline	Gasoline	IMPACO Technologies, Inc.	CFMXT05.03D7	CFMXR0265NBV	CZ9XT05.08C7-028	CZ9XR0265BNN	CZ9XT05.08C7	EPA Cert
Ford	2012	5.0	IA Bi-Fuel CNG - Ford: F150 Pickup 2WD, F150 Pickup 4WD	CNG or gasoline/E85	Gasoline/E85	IMPACO Technologies, Inc.	CFMXT05.03DD	CFMXR0265NBV	CZ9XT05.08NA-005	CZ9XR0265CB1	CZ9XT05.08NA	EPA Cert
Ford	2012	5.0	NatGasCar: F150 PICKUP 2WD, F150 PICKUP 4WD	CNG or gasoline	Gasoline/E85	Nat Gas Car LLC	CFMXT05.03D7; CFMXT05.03DD	CFMXR0265NBV	DNATT05.03DC-012-R01	DNATR0265NBV	DNATT05.03DC	EPA Cert
Ford	2012	5.4	BAF Technologies: E350 Cutaway	CNG	Gasoline/E85	BAF Technologies	CFMXE05.4AFD	CFMXR0265NBV	CBAFD05.4AFD-009	CBAFR0000001	CBAFD05.4AFD	EPA Cert, CARB
Ford	2012	5.4	BAF Technologies: Ford E-Series Van	CNG	Gasoline/E85	BAF Technologies	CFMXT05.45HK	CFMXR0265NBD; CFMXF0265NBS	CBAFT05.45HK-001	CBAFR0000001	CBAFT05.45HK	EPA Cert
Ford	2012	5.4	BAF Technologies: E150 Van, E150 Club Wagon, E250 Van, E350 Cutaway, E350 Van, E350 Club Wagon	CNG	Gasoline/E85	BAF Technologies			EO A-364-0034	CBAFR0000001	CBAFT05.4CHK	CARB
Ford	2012	5.4	Landi Renzo USA: E150 VAN CNG, E150 WAGON CNG, E250 VAN CNG, E350 CUTAWAY CNG, E350 VAN CNG, E350 WAGON CNG	CNG	Gasoline/E85	Landi Renzo USA Corporation	CFMXT05.45HK	CFMXR0265NBD; CFMXF0265NBS	CLDRT05.4A11-001-R01	CLDRT0000A11	CLDRT05.4A11	EPA Cert, CARB
Ford	2012	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD, F350 2WD Bed Delete, F350 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXR0250NBS	CAECT06.27HA-010	CAECF0250NB3	CAECT06.27HA	EPA Cert
Ford	2012	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXR0250NBS	CAECT06.27HA-011	CAECR0250NB3	CAECT06.27HA	EPA Cert
Ford	2012	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXF0265GAS	CAECT06.27HA-012	CAECF0265GA1	CAECT06.27HA	EPA Cert
Ford	2012	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD, F350 2WD Bed Delete, F350 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXR0250NBS	CAECT06.27HL-007	CAECF0250NB2	CAECT06.27HL	EPA Cert
Ford	2012	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXR0250NBS	CAECT06.27HL-008	CAECR0250NB2	CAECT06.27HL	EPA Cert

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Ford	2012	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	CFMXT06.27HL	CFMXF0265GAS	CAECT06.27HL-009	CAECF0265GAS	CAECT06.27HL	EPA Cert
Ford	2012	6.2	BAF Technologies: Ford F250/350	CNG	Gasoline/E85	BAF Technologies	CFMXT06.27HL	CFMXR0250NBS; CFMXF0250NBS; CFMXF0265GAS	CBAFT06.27HL-003	CBAFR0000001	CBAFT06.27HL	EPA Cert
Ford	2012	6.2	F250 Pickup, F350 Pickup, F350 Bed Delete, F250 Bed Delete, F350 Pickup, F350 Bed Delete, F350 Pickup DRW, F350 Bed Delete DRW, F350 Incomplete Chasis Cab	CNG	Gasoline/E85	BAF Technologies			EO 364-0035	CBAFR0000001	CBAFT06.2CHL	CARB
Ford	2012	6.2	IA Dedicated CNG - Ford: F250 Pickup 2WD, Ford F250 Pickup 4WD, Ford F350 Pickup 2WD, Ford F350 Pickup 4WD	CNG	Gasoline/E85	IMPICO Technologies, Inc.	CFMXT06.27HL	CFMXR0250NBS; CFMXF0250NBS; CFMXF0265GAS	CZ9XT06.2DCE-014	CZ9XR0000DCE	CZ9XT06.2DCE	EPA Cert, CARB
Ford	2012	6.2	IA Bi-Fuel CNG - Ford: F250 PICKUP 2WD, F250 PICKUP 4WD, F350 4WD, F350 2WD	CNG or gasoline/E85	Gasoline/E85	IMPICO Technologies, Inc.	CFMXT06.27HL	CFMXR0250NBS	CZ9XT06.2BC2-015	CZ9XR0250BCC	CZ9XT06.2BC2	EPA Cert
Ford	2012	6.2	IA Bi-Fuel CNG - Ford: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD, F350 2WD, F350 2WD Bed Delete, F350 4WD Bed Delete	CNG or gasoline/E85	Gasoline/E85	IMPICO Technologies, Inc.	CFMXT06.27HL	CFMXF0250NBS	CZ9XT06.2BC2-016	CZ9XF0250BCA	CZ9XT06.2BC2	EPA Cert
Ford	2012	6.2	IA Bi-Fuel CNG - Ford: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG or gasoline/E85	Gasoline/E85	IMPICO Technologies, Inc.	CFMXT06.27HL	CFMXF0265GAS	CZ9XT06.2BC2-017	CZ9XF0265BCB	CZ9XT06.2BC2	EPA Cert
Ford	2012	6.2	Landi Renzo USA: F250 PICKUP 2WD, F350 2WD, F350 4WD, F350 PICKUP 4WD	CNG or gasoline/E85	Gasoline/E85	Landi Renzo USA Corporation	CFMXT06.27HL	CFMXR0250NBS	CLDRT06.2C20-002	CLDRR0250NBS	CLDRT06.2C20	EPA Cert
Ford	2012	6.2	Landi Renzo USA: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG or gasoline/E85	Gasoline/E85	Landi Renzo USA Corporation	CFMXT06.27HL	CFMXF0265GAS	CLDRT06.2C20-003	CLDRF0265GAS	CLDRT06.2C20	EPA Cert
Ford	2012	6.2	Landi Renzo USA: F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD, F350 2WD BED DELETE, F350 4WD, F350 4WD BED DELETE	CNG or gasoline/E85	Gasoline/E85	Landi Renzo USA Corporation	CFMXT06.27HL	CFMXF0250NBS	CLDRT06.2C20-004	CLDRF0250NBS	CLDRT06.2C20	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXTF0250NBS; FMXTF0250NBS	DPRFT06.2HL4-010	DPRRF0250N2D	DPRFT06.2HL4	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXR0250NBS	DPRFT06.2HL4-011	DPRRF0250N2D	DPRFT06.2HL4	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXF0265GAS	DPRFT06.2HL4-012	DPRRF0265G2D	DPRFT06.2HL4	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXR0250NBS	DPRFT06.2HL3-007	DPRRF0250N2S	DPRFT06.2HL3	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXTF0250NBS; FMXTF0250NBS	DPRFT06.2HL3-008	DPRRF0250N2S	DPRFT06.2HL3	EPA Cert
Ford	2012	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	CFMXT06.27HL	CFMXF0265GAS	DPRFT06.2HL3-009	DPRRF0265G2S	DPRFT06.2HL3	EPA Cert
Ford	2012	6.2	Ford: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline/E85	Gasoline/E85	Westport Light Duty Inc.	CFMXT06.27HL	CFMXR0250NBS	CINPT06.2CNG-001	CINPR0250NBS	CINPT06.2CNG	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2012	6.2	Ford: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 2WD, F350 2WD Bed Delete, F350 4WD, F350 4WD Bed Delete	CNG or gasoline/E85	Gasoline/E85	Westport Light Duty Inc.	CFMXT06.27HL	CFMXF0250NBS	CJNPT06.2CNG-002	CJNPF0250NBS	CJNPT06.2CNG	EPA Cert
Ford	2012	6.2	Ford: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline/E85	Gasoline/E85	Westport Light Duty Inc.	CFMXT06.2HL	CFMXF0265GAS	CJNPT06.2CNG-003	CJNPF0265GAS	CJNPT06.2CNG	EPA Cert
Ford	2012	5.4, 4.6	Altech-Eco Corporation: E250 Cutaway, E350 Cutaway	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT05.45HK; CFMXT04.65H9	CFMXF0265NBS	CAECT05.45HB-015	CAECF0265NB1	CAECT05.45HB	EPA Cert
Ford	2012	5.4, 4.6	AEC: E350 Van Altech-Eco Corporation: E150 Van, E150 Wagon, E250 Van, E350 Wagon	CNG	Gasoline/E85	Altech-Eco Corporation	CFMXT05.45HK; CFMXT05.45HL; CFMXT04.65H9	CFMXR0265NBD	CAECT05.45HB-016	CAECR0265NB3	CAECT05.45HB	EPA Cert
Ford	2012	6.2, 5.4	BAF_Bifuel: E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	CFMXT05.45HK	CFMXR0265NBD	CBAFT06.254B-004	CBAFR0265NBD	CBAFT06.254B	EPA Cert
Ford	2012	6.2, 5.4	BAF_Bifuel: E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	CFMXT05.45HK	CFMXF0265NBS	CBAFT06.254B-005	CBAFF0265NBS	CBAFT06.254B	EPA Cert
Ford	2012	6.2, 5.4	BAF_Bifuel: F250/350; E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	CFMXT06.27HL	CFMXF0265GAS	CBAFT06.254B-006	CBAFF0265GAS	CBAFT06.254B	EPA Cert
Ford	2012	6.2, 5.4	BAF_Bifuel: F250/350; E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	CFMXT06.27HL	CFMXR0250NBS	CBAFT06.254B-007	CBAFR0250NBS	CBAFT06.254B	EPA Cert
Ford	2012	6.2, 5.4	BAF_Bifuel: F250/350; E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	CFMXT06.27HL	CFMXF0250NBS	CBAFT06.254B-008	CBAFF0250NBS	CBAFT06.254B	EPA Cert
Ford	2011	2.0	Altech-Eco Corporation: Transit Connect	CNG	Gasoline	Altech-Eco Corporation	BFMXT02.01DV	BFMXR0125NBB	CAECT02.01DA-018	CAECR0125NB2	CAECT02.01DA	EPA Cert
Ford	2011	2.0	Altech-Eco Corporation: Transit Connect	CNG or gasoline	Gasoline	Altech-Eco Corporation	BFMXT02.01DV	BFMXR0125NBB	CAECT02.01DV-017	CAECR0125NBB	CAECT02.01DV	EPA Cert
Ford	2011	2.0	BAF Technologies: Ford Transit Connect	CNG	Gasoline	BAF Technologies	BFMXT02.01DV	BFMXR0125NBB	BBAFT02.01DV-003	BBAFR0000001	BBAFT02.01DV	EPA Cert, CARB
Ford	2011	2.0	CNG - Dedicated Ford: Ford Transit Connect	CNG	Gasoline	EvoTek LLC	BFMXT02.01DV	BFMXR0125NBB	BETKT02.0N1A-002	BETKR00000N1A	BETKT02.0N1A	EPA Cert
Ford	2011	2.5	Altech-Eco Corporation: Fusion, Fusion S FWD, Milan, Milan S FWD	CNG	Gasoline	Altech-Eco Corporation	BFMXV02.5VEN	BFMXR0155GAV	BAECV02.5VEB-022	BAECR0155GA1	BAECV02.5VEB	EPA Cert
Ford	2011	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD, Mariner 4WD, Mariner FWD, Tribute 4WD, Tribute FWD	CNG	Gasoline	Altech-Eco Corporation	BFMXT02.51EN	BFMXR0125NBV	BAECV02.5VEB-023	BAECR0125NB1	BAECV02.5VEB	EPA Cert
Ford	2011	2.5	Altech-Eco Corporation: Fusion, Fusion S FWD, Milan, Milan S FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	BFMXV02.5VEN	BFMXR0155GAV	BAECV02.5VEN-020	BAECR0155GAV	BAECV02.5VEN	EPA Cert
Ford	2011	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD, Mariner 4WD, Mariner FWD, Tribute 4WD, Tribute FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	BFMXT02.51EN	BFMXR0125NBV	BAECV02.5VEN-021	BAECR0125NBV	BAECV02.5VEN	EPA Cert
Ford	2011	2.5	CNG - Dedicated Ford / Lincoln / Mercury: Ford Escape 4WD, Ford Escape FWD, Mazda Tribute 4WD, Mazda Tribute FWD	CNG	Gasoline	EvoTek LLC	BFMXT02.51EN	BFMXR0125NBV	BETKT02.5C1A-007	BETKR0000E1H	BETKT02.5C1A	EPA Cert
Ford	2011	2.5	CNG - Dedicated Ford / Lincoln / Mercury: Ford Fusion, Ford Fusion S	CNG	Gasoline	EvoTek LLC	BFMXV02.5VEN	BFMXR0155GAV	BETKV02.5C1A-008	BETKR0000E1I	BETKV02.5C1A	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2011	3.7	CNG - Dedicated Ford / Lincoln / Mercury: Ford F150 4WD, Ford F150 Pickup 2WD	CNG	Gasoline/E85	EvoTek LLC	BFMXV04.73DP	BFMXR0265NBV	BETKT03.7N1A-012	BETKR0000E1F	BETKT03.7N1A	EPA Cert
Ford	2011	4.6	CNG - Dedicated Ford / Lincoln / Mercury: Crown Victoria FFV, Crown Victoria Police FFV, Grand Marquis FFV, Town Car FFV	CNG	Gasoline/E85	EvoTek LLC	BFMXV04.6VDF; BFMXV04.6VHF	BFMXR0115GAA	BETKV04.6N1A-006		BETKV04.6N1A	EPA Cert
Ford	2011	4.6	Bi-Fuel CNG - Ford / Lincoln / Mercury: Crown Victoria Police, Grand Marquis, Town Car	CNG or gasoline/E85	Gasoline/E85	EvoTek LLC	BFMXV04.6VDF; BFMXV04.6VHF	BFMXR0115GAA	BETKV04.6BCA-010	BETKR0115E1J	BETKV04.6BCA	EPA Cert
Ford	2011	4.6	Go Natural CNG: Crown Victoria, Crown Victoria Police, Grand Marquis, Town Car	CNG	Gasoline/E85	Go Natural CNG, LLC	BFMXV04.6VDF	BFMXR0115GAA	CGNLV04.6F1B-004	CGNLR0115F1B	CGNLV04.6F1B	EPA Cert
Ford	2011	4.6	Go Natural CNG: Crown Victoria, Crown Victoria Police, Grand Marquis, Town Car	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXV04.6VDF	BFMXR0115GAA	CGNLV04.6F2B-005	CGNLR0115F2B	CGNLV04.6F2B	EPA Cert
Ford	2011	5.0	AEC: F150 Pickup 2WD Altech-Eco Corporation: F150 Pickup 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT05.03DD	BFMXR0265NBV	BAECT05.03DA-030-R01	BAECR0265NB1	BAECT05.03DA	EPA Cert
Ford	2011	5.0	AEC: F150 Pickup 2WD Altech-Eco Corporation: F150 Pickup 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	BFMXT05.03DD	BFMXR0265NBV	BAECT05.03DD-031	BAECR0265NBV	BAECT05.03DD	EPA Cert
Ford	2011	5.0	IA Bi-Fuel CNG - Ford: F150 Pickup 2WD, F150 Pickup 4WD	CNG or gasoline/E85	Gasoline/E85	IMPACO Technologies, Inc.	BFMXT05.03DD	BFMXR0265NGV	BZ9XT05.08NA-052	BZ9XR0265CB1	BZ9XT05.08NA	EPA Cert
Ford	2011	5.0	Ford: F150 truck 2WD, F150 truck 4WD	CNG or gasoline	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMXT05.03DD	BFMXR0265NBV	EPRFT05.03D1-009-R01	EPRFR0265NBV	EPRFT05.03D1	EPA Cert
Ford	2011	5.4	AEC: E350 Van Altech-Eco Corporation: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT05.45HK; BFMXT05.45HL	BFMXR0265NBD	CAECT05.45HA-001	CAECR0265NBD	CAECT05.45HA	EPA Cert
Ford	2011	5.4	Altech-Eco Corporation: E350 Cutaway	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT05.45HK; BFMXT05.45HL	BFMXF0265NBS	CAECT05.45HA-002	CAECF0265NBS	CAECT05.45HA	EPA Cert
Ford	2011	5.4	BAF Technologies: Ford E-Series Van	CNG	Gasoline/E85	BAF Technologies	BFMXT05.45HK	BFMXR0265NBD; BFMXF0265NBS	BBAFT05.45HK-004	BBAFR0000001	BBAFT05.45HK	EPA Cert
Ford	2011	5.4	BAF Technologies: Ford E-Series Van and Club Wagon 150, 250, 350, E 350 Cutaway	CNG	Gasoline/E85	BAF Technologies	BFMXT05.45HK	BFMXR0265NBD; BFMXF0265NBS	BBAFT05.45HK-004	BBAFR0000001	BBAFT05.45HK	EPA Cert, CARB
Ford	2011	5.4	CNG - Dedicated Ford: Ford Econoline 250/350	CNG	Gasoline/E85	EvoTek LLC	BFMXT05.45HL; BFMXT05.45HK	BFMXR0265NBD	BETKT05.4N1A-001	BETKR0000N1B	BETKT05.4N1A	EPA Cert
Ford	2011	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, Navigator 2WD, Navigator 4WD	CNG	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.44HY; BFMXT05.44BC	BFMXR0265NBC	BGNLT05.4F3B-018-R01	BGNLR0265F3B	BGNLT05.4F3B	EPA Cert
Ford	2011	5.4	Go Natural CNG: E150 Van, E150 Wagon, E250 Van, E350 Cutaway, E350 Van, E350 Wagon, Expedition 2WD, Navigator 2WD	CNG	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.45BR; BFMXT05.45HK; BFMXT05.45HL	BFMXR0265NBD; BFMXF0265NBS	CGNLT05.4F1B-002	CGNLR0000000	CGNLT05.4F1B	EPA Cert
Ford	2011	5.4	Go Natural CNG: E350 Van	CNG or gasoline	Gasoline	Go Natural CNG, LLC	BFMXT05.45HL	BFMXR0265NBD	BGNLT05.4F9B-016	BGNLR0265FAB	BGNLT05.4F9B	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2011	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, Navigator 2WD, Navigator 4WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.44BC	BFMXR0265NBC	BGNLT05.4F4B-005	BGNLR0265F4B	BGNLT05.4F4B	EPA Cert
Ford	2011	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, Navigator 2WD, Navigator 4WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.44HY	BFMXR0265NBC	BGNLT05.4F5B-006	BGNLR0265F5B	BGNLT05.4F5B	EPA Cert
Ford	2011	5.4	Go Natural CNG: E350 Cutaway	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.45HK	BFMXF0265NBS	BGNLT05.4F6B-008	BGNLF0265FDB	BGNLT05.4F6B	EPA Cert
Ford	2011	5.4	Go Natural CNG: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.45HK	BFMXR0265NBD	BGNLT05.4F6B-009	BGNLR0265FCB	BGNLT05.4F6B	EPA Cert
Ford	2011	5.4	Go Natural CNG: Expedition 2WD, Navigator 2WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	BFMXT05.45BR	BFMXR0265NBC	BGNLT05.4F6B-010	BGNLR0265FBB	BGNLT05.4F6B	EPA Cert
Ford	2011	5.4	IA Bi-Fuel CNG - Ford: Ford E150 Van, Ford E150 Wagon, Ford E250 Van, Ford E350 Van, Ford E350 Wagon	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	BFMXT05.45HK	BFMXR0265NBD	BZ9XT05.4CB1-057	BZ9XR0265BCC	BZ9XT05.4CB1	EPA Cert
Ford	2011	5.4	Landi Renzo USA: E150 VAN CNG, E150 WAGON CNG, E250 VAN CNG, E350 CUTAWAY CNG, E350 VAN CNG, E350 WAGON CNG	CNG	Gasoline	Landi Renzo USA Corporation	BFMXT05.45HK		BLDRT05.4A10-001	BLDRT0000A10	BLDRT05.4A10	EPA Cert, CARB
Ford	2011	5.4	Landi Renzo USA: E150 VAN CNG, E150 WAGON CNG, E250 VAN CNG, E350 CUTAWAY CNG, E350 VAN CNG, E350 WAGON CNG	CNG	Gasoline/E85	Landi Renzo USA Corporation	BFMXT05.45HK	BFMXR0265NBD; BFMXF0265NBS	BLDRT05.4A11-003	BLDRT0000A11	BLDRT05.4A11	EPA Cert, CARB
Ford	2011	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXR0250NBS	BAECT06.27HA-027	BAECR0250NB3	BAECT06.27HA	EPA Cert
Ford	2011	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD Bed Delete, F350 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXF0250NBS	BAECT06.27HA-028	BAECF0250NB3	BAECT06.27HA	EPA Cert
Ford	2011	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXF0265GAS	BAECT06.27HA-029	BAECF0265GA1	BAECT06.27HA	EPA Cert
Ford	2011	6.2	Altech-Eco Corporation: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXR0250NBS	BAECT06.27HL-024	BAECR0250NB2	BAECT06.27HL	EPA Cert
Ford	2011	6.2	Altech-Eco Corporation: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 4WD Bed Delete, F350 2WD Bed Delete, F350 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXF0250NBS	BAECT06.27HL-025	BAECF0250NB2	BAECT06.27HL	EPA Cert
Ford	2011	6.2	Altech-Eco Corporation: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline/E85	Gasoline/E85	Altech-Eco Corporation	BFMXT06.27HL	BFMXF0265GAS	BAECT06.27HL-026	BAECF0265GAS	BAECT06.27HL	EPA Cert
Ford	2011	6.2	BAF Technologies: Ford F250/350	CNG	Gasoline	BAF Technologies	BFMXT06.27HL	BFMXR0250NBS; BFMXF0250NBS; BFMXF0265GAS	BBAFT06.27HL-005	BBAFR0000001	BBAFT06.27HL	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2011	6.2	CNG - Dedicated Ford: Ford F250/F350	CNG	Gasoline/E85	EvoTek LLC	BFMX06.27HL	BFMXR0250NBS; BFMXF0250NBS; BFMXF0265GAS	BETKT06.2N2A-003	BETKR0000E1C	BETKT06.2N2A	EPA Cert
Ford	2011	6.2	CNG - Dedicated Ford / Lincoln / Mercury: F150 Raptor Pickup 4WD, Ford F150 4WD, Ford F150 Pickup 2WD	CNG	Gasoline	EvoTek LLC	BFMX06.24D2	BFMXR0265NBV	BETKT06.2DNH-013	BETKR0000HDT	BETKT06.2DNH	EPA Cert
Ford	2011	6.2	Bi-Fuel CNG - Ford / Lincoln / Mercury: Ford F250/F350	CNG or gasoline	Gasoline/E85	EvoTek LLC	BFMX06.27HL	BFMXF0250NBS	BETKT06.2B2A-009	BETKR0000E1D	BETKT06.2B2A	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXF0250NBD	DPRT06.2HL2-004	DPRFF0250NBD	DPRT06.2HL2	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXF0265GAS	DPRT06.2HL2-005	DPRFF0265GAD	DPRT06.2HL2	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXR0250NBD	DPRT06.2HL2-006	DPRFR0250NBD	DPRT06.2HL2	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXR0250NBS	DPRT06.2HL1-001	DPRFR0250NBS	DPRT06.2HL1	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXF0250NBS	DPRT06.2HL1-002	DPRFF0250NBS	DPRT06.2HL1	EPA Cert
Ford	2011	6.2	Ford: F250/350 trucks	CNG or gasoline/E85	Gasoline/E85	PowerFuel CNG Conversions, LLC	BFMX06.27HL	BFMXF0265GAS	DPRT06.2HL1-003	DPRFF0265GAS	DPRT06.2HL1	EPA Cert
Ford	2011	5.4, 4.6	Altech-Eco Corporation: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG	Gasoline/E85	Altech-Eco Corporation	BFMX05.45HK; BFMX05.45HL; BFMX04.65H9	BFMXR0265NBD	BAECT05.45HA-032	BAECR0265NB3	BAECT05.45HA	EPA Cert
Ford	2011	5.4, 4.6	Altech-Eco Corporation: E250 Cutaway, E350 Cutaway	CNG	Gasoline/E85	Altech-Eco Corporation	BFMX05.45HK; BFMX04.65H9	BFMXF0265NBS	BAECT05.45HA-033	BAECF0265NB1	BAECT05.45HA	EPA Cert
Ford	2011	5.4, 6.2	BAF_Bifuel: F250/350; E250/350	CNG or gasoline/E85	Gasoline/E85	BAF Technologies	BFMX06.27HL; BFMX05.45HK	BFMXR0250NBS; BFMXF0250NBS; BFMXR0265NBD; BFMXF0265NBS	BBAFT06.254B-006-R01	BBAFR00000002	BBAFT06.254B	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Transit Connect	CNG	Gasoline	Altech-Eco Corporation	AFMX02.01DV	AFMXR0125NBB	AAECT02.01DA-008	AAECR0125NB1	AAECT02.01DA	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG	Gasoline	Altech-Eco Corporation	AFMX02.0VZX	AFMXR0110GCX	AAECV02.0VZA-002	AAECR0125NC1	AAECV02.0VZA	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG	Gasoline	Altech-Eco Corporation	AFMX02.0VXD	AFMXR0125NAA	AAECV02.0VZA-003	AAECR0125NA1	AAECV02.0VZA	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG	Gasoline	Altech-Eco Corporation	AFMX02.0VEC	AFMXR0110GAA	BAECV02.0VEA-019	BAECR0110GA1	BAECV02.0VEA	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Transit Connect	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMX02.01DV		AAECT02.01DV-007	AAECR0125NBB	AAECT02.01DV	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMX02.0VXD	AFMXR0125NAA	AAECV02.0VXD-004	AAECR0125NAA	AAECV02.0VXD	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMX02.0VZX	AFMXR0125NCX	AAECV02.0VZX-001	AAECR0125NCX	AAECV02.0VZX	EPA Cert
Ford	2010	2.0	Altech-Eco Corporation: Focus	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMX02.0VEC	AFMXR0110GAA	BAECV02.0VEC-018	BAECR0110GAA	BAECV02.0VEC	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2010	2.0	CNG - Dedicated: Ford Transit Connect	CNG	Gasoline	EvoTek LLC	AFMXT02.01DV	AFMXR0125NBB	AETKT02.0N1A-002	AETKR0000N1A	AETKT02.0N1A	EPA Cert
Ford	2010	2.0	CNG - Dedicated: Ford Focus	CNG	Gasoline	EvoTek LLC	AFMXV02.0VEG; AFMXV02.0VZX	AFMXR0110GAA; AFMXR0125NXC	AETKV02.0N1A-003	AETKR0000N1C	AETKV02.0N1A	EPA Cert
Ford	2010	2.0	IMPCO Technologies, Inc.: Ford Transit Connect	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	AFMXT02.01DV	AFMXR0125NBB	CZ9XT02.0FFA-001	CZ9XR0125FFA	CZ9XT02.0FFA	EPA Cert
Ford	2010	2.3	FORD RANGER 4X2, MAZDA B2300 4X2	CNG	Gasoline	Go Natural CNG	AFMXT02.31EL	AFMXR0160GBB		DGNL R0160GBB	DGNL T02.3110	Int Appr
Ford	2010	2.5	Altech-Eco Corporation: Fusion, Milan	CNG	Gasoline	Altech-Eco Corporation	AFMXV02.5VEF	AFMXR0155GAV	BAECV02.5VEA-001	BAECR0155GA1	BAECV02.5VEA	EPA Cert
Ford	2010	2.5	Altech-Eco Corporation: Fusion FWD, Fusion S FWD, Milan FWD, Milan S FWD	CNG	Gasoline	Altech-Eco Corporation	AFMXV02.5VEN	AFMXR0155GAV	CAECV02.51EA-005	CAECR0155GA1	CAECV02.51EA	EPA Cert
Ford	2010	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD, Mariner 4WD, Mariner FWD, Tribute 4WD, Tribute FWD	CNG	Gasoline	Altech-Eco Corporation	AFMXT2.51EN,	AFMXR0125NBV	CAECV02.51EA-006	CAECR0125NB1	CAECV02.51EA	EPA Cert
Ford	2010	2.5	Altech-Eco Corporation: Fusion, Milan	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXV02.5VEF	AFMXR0155GAV	BAECV02.5VEF-002	BAECR0155GAV	BAECV02.5VEF	EPA Cert
Ford	2010	2.5	Altech-Eco Corporation: Fusion FWD, Fusion S FWD, Milan FWD, Milan S FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXV02.5VEN	AFMXR0155GAV	CAECV02.51EN-003	CAECR0155GAV	CAECV02.51EN	EPA Cert
Ford	2010	2.5	Altech-Eco Corporation: Escape 4WD, Escape FWD, Mariner 4WD, Mariner FWD, Tribute 4WD, Tribute FWD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXT02.51EN	AFMXR0125NBV	CAECV02.51EN-004	CAECR0125NBV	CAECV02.51EN	EPA Cert
Ford	2010	4.6	Altech-Eco Corporation: F150 Pickup 2WD, F150 Pickup 4WD, F150 SFE 2WD	CNG	Gasoline	Altech-Eco Corporation	AFMXT04.64D3; AFMXT04.63DF; AFMXT04.63D2	AFMXR0265NBC	BAECT04.64DB-017	BAECR0265NB2	BAECT04.64DB	EPA Cert
Ford	2010	4.6	BAF Technologies: Town Car, Crown Victoria, Grand Marquis, Town Car Limo	CNG	Gasoline/E85	BAF Technologies	AFMXV04.6VDF; AFMXV04.6VE3	AFMXR0115GAA	ABAFV04.61FN-003	ABAFR0000001	ABAFV04.61FN	EPA Cert, CARB
Ford	2010	4.6	CROWN VICTORIA, CROWN VICTORIA POLICE, GRAND MARQUIS, TOWN CAR	CNG	Gasoline, Ethanol	Go Natural CNG	AFMXV04.6VDF	AFMXR0115GAA		CGNLR0115F1A	CGNLV04.6F1A	Int Appr
Ford	2010	4.6	Mustang	CNG	Gasoline	Go Natural CNG	AFMXV04.6VDM	AFMXR0125NCA		CGNLR0125F1A	CGNLV04.6F1A	Int Appr
Ford	2010	4.6	Go Natural CNG: Crown Victoria, Crown Victoria Police, Grand Marquis, Town Car	CNG or gasoline	Gasoline/E85	Go Natural CNG, LLC	AFMXV04.6VDF	AFMXR0115GAA	BGNLV04.6F2A-001	BGNLR0115F2A	BGNLV04.6F2A	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.47V8	AFMXF0120GAS	BAECD05.46VA-003	BAECF0120GA1	BAECD05.46VA	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD, F350 2WD BED DELETE, F350 4WD, F350 4WD BED DELETE	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.46VX; AFMXD05.47V8; AFMXD05.47VT	AFMXF0250NBS	BAECD05.46VA-004	BAECF0250NB1	BAECD05.46VA	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2010	5.4	Altech-Eco Corporation: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.46VX; AFMXD05.47V8; AFMXD05.47VT	AFMXF0260GAS	BAECD05.46VA-005	BAECF0260GA1	BAECD05.46VA	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.46VX	AFMXR0250NBS	BAECD05.46VA-006	BAECR0250NB1	BAECD05.46VA	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD BED DELETE, F350 4WD BED DELETE	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.46VR	AFMXF0250NBS	BAECT05.46VB-013	BAECF0250NB1	BAECT05.46VB	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	CNG	Gasoline	Altech-Eco Corporation	AFMXD05.46VR	AFMXR0250NBS	BAECT05.46VB-014	BAECR0250NB1	BAECT05.46VB	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG	Gasoline/E85	Altech-Eco Corporation	AFMXT05.45H4; AFMXT05.45HJ	AFMXR0265NAD	BAECT05.46VB-015	BAECR0265NA1	BAECT05.46VB	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: E350 Cutaway	CNG	Gasoline/E85	Altech-Eco Corporation	AFMXT05.45H4; AFMXT05.45HJ	AFMXF0265NAS	BAECT05.46VB-016	BAECF0265NA1	BAECT05.46VB	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD BED DELETE, F350 4WD BED DELETE	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.46VX; AFMXD05.46VR	AFMXF0250NBS	BAECD05.46VX-010	BAECF0250NBS	BAECD05.46VX	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.46VX; AFMXD05.46VR	AFMXF0260GAS	BAECD05.46VX-011	BAECF0260GAS	BAECD05.46VX	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.46VX; AFMXD05.46VR	AFMXR0250NBS	BAECD05.46VX-012	BAECR0250NBS	BAECD05.46VX	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.47V8	AFMXF0120GAS	BAECD05.47V8-007	BAECF0120GAS	BAECD05.47V8	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F350 2WD, F350 2WD BED DELETE, F350 4WD, F350 4WD BED DELETE	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.47V8; AFMXD05.47VT	AFMXF0250NBS	BAECD05.47V8-008	BAECF0250NBS	BAECD05.47V8	EPA Cert
Ford	2010	5.4	Altech-Eco Corporation: F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG or gasoline	Gasoline	Altech-Eco Corporation	AFMXD05.47V8; AFMXD05.47VT	AFMXF0260GAS	BAECD05.47V8-009	BAECF0260GAS	BAECD05.47V8	EPA Cert
Ford	2010	5.4	BAF Technologies: F-150, Expedition, Navigator	CNG	Gasoline	BAF Technologies	AFMXT05.44BC	AFMXR0265NBC	ABAF05.41FN-002	ABAFR0000001	ABAF05.41FN	EPA Cert, CARB
Ford	2010	5.4	BAF Technologies: Econoline E150, 250, 350, E150 Club Wagon, E350 Club Wagon, E350 Cutaway	CNG	Gasoline	BAF Technologies	AFMXT05.45H4		ABAF05.42FN-001	ABAFR0000001	ABAF05.42FN	EPA Cert, CARB
Ford	2010	5.4	CNG - Dedicated: Ford Econoline 250/350	CNG	Gasoline	EvoTek LLC	AFMXT05.45H4	AFMXR0265NAS	AETKT05.4N1A-001	AETKR0000N1A	AETKT05.4N1A	EPA Cert
Ford	2010	5.4	CNG - Dedicated: Ford Econoline 250/350	CNG	Gasoline	EvoTek LLC	AFMXT05.45H4	AFMXR0265NAS	AETKT05.4N1A-001	AETKR0000N1A	AETKT05.4N1A	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2010	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, F150 2WD, F150 4WD, Navigator 2WD, Navigator 4WD	CNG	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.44ET; AFMXT05.44HY; AFMXT05.44BC	AFMXR0265NBC	BGNLT05.4F1A-017	BGNLR0265F1A	BGNLT05.4F1A	EPA Cert
Ford	2010	5.4	Go Natural CNG: E150 Van, E150 Wagon, E250 Van, E350 Cutaway, E350 Van, E350 Wagon, Expedition 2WD, F250 2WD Bed Delete, F250 4WD Bed Delete, F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 2WD Bed Delete, F350 4WD, F350 4WD Bed Delete, F350 Incomplete 2WD, F350 Incomplete 4WD, Navigator 2WD	CNG	Gasoline/E85	Go Natural CNG, LLC	AFMXD05.46VR; AFMXD05.46VX; AFMXT05.45BR; AFMXT05.45HJ; AFMXT05.45H4	AFMXR0265NBC; AFMXR0265GAS; AFMXR0265NBC; AFMXR0265NAS; AFMXR0265NAD	CGNLT05.4F1A-001	CGNLR0000000	CGNLT05.4F1A	EPA Cert
Ford	2010	5.4	Go Natural CNG: F250 2WD Bed Delete, F250 4WD Bed Delete, F350 2WD Bed Delete, F350 4WD Bed Delete	CNG or gasoline	Gasoline	Go Natural CNG, LLC	AFMXD05.46VR; AFMXD05.46VX	AFMXR0250NBS	BGNLD05.4F7A-007	BGNLF0250FAA	BGNLD05.4F7A	EPA Cert
Ford	2010	5.4	Go Natural CNG: F350 Incomplete 2WD, F350 Incomplete 4WD	CNG or gasoline	Gasoline	Go Natural CNG, LLC	AFMXD05.46VX	AFMXR0260GAS	BGNLD05.4F7A-011	BGNLF0260FBA	BGNLD05.4F7A	EPA Cert
Ford	2010	5.4	Go Natural CNG: F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 4WD	CNG or gasoline	Gasoline	Go Natural CNG, LLC	AFMXD05.46VR; AFMXD05.46VX	AFMXR0250NBS	BGNLD05.4F7A-012	BGNLR0250FCA	BGNLD05.4F7A	EPA Cert
Ford	2010	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, F150 2WD, F150 4WD, Navigator 2WD, Navigator 4WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.44BC	AFMXR0265NBC	BGNLT05.4F2A-003	BGNLR0265F2A	BGNLT05.4F2A	EPA Cert
Ford	2010	5.4	Go Natural CNG: Expedition 2WD, Navigator 2WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.45BR	AFMXR0265NBC	BGNLT05.4F3A-013-R02	BGNLR0265FDA	BGNLT05.4F3A	EPA Cert
Ford	2010	5.4	Go Natural CNG: E150 Van, E150 Wagon, E250 Van, E350 Van, E350 Wagon	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.45HJ; AFMXT05.45H4	AFMXR0265NAD	BGNLT05.4F3A-014-R02	BGNLR0265FEA	BGNLT05.4F3A	EPA Cert
Ford	2010	5.4	Go Natural CNG: E350 Cutaway	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.45HJ; AFMXT05.45H4	AFMXR0265NAS	BGNLT05.4F3A-015-R02	BGNLF0265FFA	BGNLT05.4F3A	EPA Cert
Ford	2010	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, F150 2WD, F150 4WD, Navigator 2WD, Navigator 4WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.44ET	AFMXR0265NBC	BGNLT05.4F4A-004-R01	BGNLR0265F4A	BGNLT05.4F4A	EPA Cert
Ford	2010	5.4	Go Natural CNG: Expedition 2WD, Expedition 4WD, Navigator 2WD, Navigator 4WD	CNG or gasoline/E85	Gasoline/E85	Go Natural CNG, LLC	AFMXT05.44HY	AFMXR0265NBC	BGNLT05.4F6A-002	BGNLR0265F6A	BGNLT05.4F6A	EPA Cert
Ford	2010	5.4	IMPACO Technologies, Inc.: FORD EXPEDITION 2WD FFV, FORD EXPEDITION 4WD FFV, FORD F150 FFV 2WD, FORD F150 FFV 4WD, LINCOLN NAVIGATOR 2WD FFV, LINCOLN NAVIGATOR 4WD FFV	CNG or gasoline	Gasoline	IMPACO Technologies, Inc.	AFMXT05.44BC	AFMXR0265NBC	BZ9XT05.4F4A-038	BZ9XR0265FFA	BZ9XT05.4F4A	EPA Cert
Ford	2010	5.4	IMPACO Technologies, Inc.: Ford E350 CUTAWAY FFV	CNG or gasoline/E85	Gasoline/E85	IMPACO Technologies, Inc.	AFMXT05.45H4	AFMXR0265NAS	BZ9XT05.4F2A-032	BZ9XF0265F2A	BZ9XT05.4F2A	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2010	5.4	IMPCO Technologies, Inc.: Ford E150 VAN FFV, Ford E150 WAGON FFV, Ford E250 VAN FFV, Ford E350 VAN FFV	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AFMXT05.45H4	AFMXR0265NAD	BZ9XT05.4F2A-031	BZ9XR0265F2A	BZ9XT05.4F2A	EPA Cert
Ford	2010	5.4	IMPCO Technologies, Inc.: Ford E350 CUTAWAY FFV	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AFMXT05.45HJ	AFMXF0265NAS	BZ9XT05.4F6A-042	BZ9XF0265F2A	BZ9XT05.4F6A	EPA Cert
Ford	2010	5.4	IMPCO Technologies, Inc.: Ford E150 VAN FFV, Ford E150 WAGON FFV, Ford E250 VAN FFV, Ford E350 VAN FFV, Ford E350 WAGON FFV	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AFMXT05.45HJ	AFMXR0265NAD	BZ9XT05.4F6A-043	BZ9XR0265F2A	BZ9XT05.4F6A	EPA Cert
Ford	2010	5.4	IMPCO Technologies, Inc.: FORD EXPEDITION 2WD FFV, FORD EXPEDITION 4WD FFV, FORD F150 FFV 2WD, FORD F150 FFV 4WD, LINCOLN NAVIGATOR 2WD FFV, LINCOLN NAVIGATOR 4WD FFV	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AFMXT05.44ET	AFMXR0265NBC	BZ9XT05.4FFA-016	BZ9XR0265FFA	BZ9XT05.4FFA	EPA Cert
Ford	2010	5.4	NGV Conversion, Inc.: E-Series Van, complete or incomp	CNG	Gasoline/E85	NGV Motori	AFMXT05.45HJ	AFMXR0265NAD	BNGCT05.45HJ-003	BNGCR00000001	BNGCT05.45HJ	EPA Cert
Ford	2010	6.8	E-450	CNG	Gasoline	BAF Technologies	AFMXE06.8BWV	AFMXF0265NAT	BAF-ONHWY-10-01	ABAF00000001	ABAF06.89FN	EPA Cert
Ford	2010	6.8	FORD: E350 VAN, E350 WAGON	CNG or gasoline/E85	Gasoline/E85	PARNELL USA, INC	AFMXT06.85HG	AFMXR0265NAD	BPRLT06.85HG-002	BPRLR0265NAD	BPRLT06.85HG	EPA Cert
Ford	2009	2.0	Altech-Eco Corporation: Focus	CNG or gasoline	Gasoline	Altech-Eco Corporation	9FMXV02.0VDF; 9FMXV02.0VZX	9FMXR0125NAA	AAECV02.0VDF-005	AAECR0125NAA	AAECV02.0VDF	EPA Cert
Ford	2009	2.0	Altech-Eco Corporation: Focus	CNG or gasoline	Gasoline	Altech-Eco Corporation	9FMXV02.0VZP; 9FMXV02.0VZX	9FMXR0125NCX	AAECV02.0VDG-006	AAECR0125NCX	AAECV02.0VDG	EPA Cert
Ford	2009	2.0	NGV Conversion, Inc.: FOCUS	CNG	Gasoline	NGV Conversion, Inc.	9FMXV02.0VZP; 9FMXV02.0VZX	9FMXR0125NCX	ANGCV02.0VZP-002	ANGCR0000CNG	ANGCV02.0VZP	EPA Cert
Ford	2009	2.0	NGV Conversion, Inc.: FOCUS	CNG	Gasoline	NGV Conversion, Inc.	9FMXV02.0VZP; 9FMXV02.0VZX	9FMXR0125NCX	BNGCV02.0VZP-002	BNGCR0000CNG	BNGCV02.0VZP	EPA Cert
Ford	2009	2.3	FORD RANGER 4X2, MAZDA B2300 4X2	CNG	Gasoline	Go Natural CNG	9FMXT02.31EL	9FMXR0160GGB	DGNLRT02.3109	DGNLR0160GGB	DGNLRT02.3109	Int Appr
Ford	2009	4.6	Town Car, Crown Victoria, Grand Marquis	CNG	Gasoline	BAF Technologies	9FMXV04.6VDF; 9FMXV04.6VE3	9FMXR0115GAA	BBAFV04.61CN-002	BBAFR00000001	BBAFV04.61CN	EPA Cert, CARB
Ford	2009	4.6	BAF Technologies: Town Car/Crown Victoria	CNG	Gasoline	BAF Technologies	9FMXV04.6VDF; 9FMXV04.6VE3	9FMXR0115GAA	BBAFV04.61FN-001	BBAFR00000001	BBAFV04.61FN	EPA Cert
Ford	2009	4.6	CROWN VICTORIA, CROWN VICTORIA POLICE, GRAND MARQUIS, TOWN CAR	CNG	Gasoline, Ethanol	Go Natural CNG	9FMXV04.6VDF	9FMXR0115GAA	CGNLR0115F19	CGNLV04.6F19	CGNLR0115F19	Int Appr
Ford	2009	4.6	CROWN VICTORIA, CROWN VICTORIA POLICE, GRAND MARQUIS, TOWN CAR	Gasoline/E85/CNG	Gasoline, Ethanol	Go Natural CNG	9FMXV04.6VDF	9FMXR0115GAA	CGNLR0115F29	CGNLV04.6F29	CGNLR0115F29	Int Appr
Ford	2009	5.4	F-150, EXPEDITION, NAVIGATOR	CNG	Gasoline	BAF Technologies			EO A-364-0018	9BAFR00000001	9BAFT05.41CN	CARB
Ford	2009	5.4	E-150 CLUB WAGON, E-350 CLUB WAGON, E-150 VAN, E-250 VAN, E-350 VAN, E-350 CUTAWAY	CNG	Gasoline	BAF Technologies			EO A-364-0015	9BAFR00000001	9BAFT05.40CN	CARB

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2009	5.4	F-250 2WD, F-250 4WD, F-350 WD, F-350 4WD	CNG	Gasoline	BAF Technologies			EO A-364-0017	9BAFR0000001	9BAFD05.43CN	CARB
Ford	2009	5.4	Go Natural CNG: E150 Van, E150 Wagon, E250 Van, E350 Cutaway, E350 Van, E350 Wagon, Expedition 2WD, F250 2WD Bed Delete, F250 4WD Bed Delete, F250 Pickup 2WD, F250 Pickup 4WD, F350 2WD, F350 2WD Bed Delete, F350 4WD, F350 4WD Bed Delete, F350 Incomplete 4WD, F350 Incomplete 4WD, Navigator 2WD	CNG	Gasoline/E85	Go Natural CNG	9FMXD05.46R6; 9FMXT05.45BR; 9FMXT05.45H4	9FMXF0260GAS; 9FMXF0250NBS; 9FMXRO250NBS; 9FMXRO265NBR; 9FMXRO265NAS; 9FMXF0265NAS	CGNLT05.4F19-003	CGNLR0000000	CGNLT05.4F19	EPA Cert
Ford	2009	5.4	F150 2WD, F150 4WD, NAVIGATOR 2WD, NAVIGATOR 4WD, EXPEDITION 2WD, EXPEDITION 4WD	CNG	FFV	Go Natural CNG	9FMXT05.44ET	9FMXR0265NBR		BGNLR0265F19	BGNLT05.4F19	Int Appr
Ford	2009	5.4	F250 BED DELETE 2WD, F250 BED DELETE 4WD, F350 BED DELETE 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	9FMXD05.46R6	9FMXF0250NBS		BGNLF0250FA9	BGNLD05.4F49	Int Appr
Ford	2009	5.4	F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	9FMXD05.46R6	9FMXF0260GAS		BGNLF0260F89	BGNLD05.4F49	Int Appr
Ford	2009	5.4	F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	9FMXD05.46R6	9FMXRO250NBS		BGNLR0250FC9	BGNLD05.4F49	Int Appr
Ford	2009	5.4	F150 2WD, F150 4WD, NAVIGATOR 2WD, NAVIGATOR 4WD, EXPEDITION 2WD, EXPEDITION 4WD	Gasoline/E85/CNG	E85	Go Natural CNG	9FMXT05.44ET	9FMXR0265NBR		BGNLR0265F29	BGNLT05.4F29	Int Appr
Ford	2009	5.4	E350 CUTAWAY	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	9FMXT05.45H4	9FMXF0265NAS		BGNLF0265FF9	BGNLT05.4F89	Int Appr
Ford	2009	5.4	EXPEDITION 2WD, NAVIGATOR 2WD	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	9FMXT05.45BR	9FMXR0265NBR		BGNLR0265FD9	BGNLT05.4F89	Int Appr
Ford	2009	5.4	E150 VAN, E150 WAGON, E250 VAN, E350 VAN, E350 WAGON	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	9FMXT05.45H4	9FMXR0265NAS		BGNLR0265FE9	BGNLT05.4F89	Int Appr
Ford	2009	5.4	IMPCO Technologies, Inc.: FORD EXPEDITION 2WD FFV, FORD EXPEDITION 4WD FFV, FORD F150 FFV 2WD, FORD F150 FFV 4WD, LINCOLN NAVIGATOR 2WD FFV, LINCOLN NAVIGATOR 4WD FFV	Gasoline/E85/CNG	Gasoline/E85	IMPCO Technologies, Inc.	9FMXT05.44ET	9FMXR0265NBR	BZ9XT05.4FF9-014	BZ9XR0265FF9	BZ9XT05.4FF9	EPA Cert
Ford	2009	6.8	E-450	CNG	Gasoline	BAF Technologies	9FMXE06.88WX	9FMXF0265NAT	BAF-ONHWY-09-01	9BAFF00000001	9BAFE06.89FN	EPA Cert
Ford	2009	6.8	E450, E450 CUTAWAY, E450 INCOMPLETE CHASSIS	CNG	Gasoline	NGV Motori	9FMXE06.88WK	9FMXF0265NAT		BNGCR000000001	BNGCT06.8NG2	Int Appr
Ford	2009	6.8	E450	CNG	Gasoline	NGV Motori	8FMXH06.8A54	8FMXE0265GAT		BNGCR000000001	BNGCT06.8NG3	Int Appr
Ford	2009	6.8	E450, E450 CUTAWAY, E450 INCOMPLETE CHASSIS	CNG	Gasoline	NGV Motori	9FMXE06.8AFA	9FMXF0265NAT		BNGCR000000001	BNGCT06.8NG4	Int Appr
Ford	2008	2.3	FORD RANGER 4X2, MAZDA B2300 4X2	CNG	Gasoline	Go Natural CNG	8FMXT02.31EL	8FMXR0165GBL		DGNLR0165GBL	DGNLT02.3108	Int Appr
Ford	2008	4.0	FORD RANGER 4X2, FORD RANGER 4X4, MAZDA B4000 4X2, MAZDA B4000 4X4	Gasoline/CNG	Gasoline	Auto Gas America	8FMXT04.02EG	8FMXR0165GBL		CAGTR0165GBL	CAGTT04.0008	Int Appr

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2008	4.6	CROWN VICTORIA FFV, CROWN VICTORIA POLICE FFV, GRAND MARQUIS FFV, TOWN CAR FFV	CNG	Gasoline/E85	Go Natural CNG	8FMXV04.6VEF	8FMXR0115GAK		CGNLR0115F18	CGNLV04.6F18	Int Appr
Ford	2008	4.6	CROWN VICTORIA FFV, CROWN VICTORIA POLICE FFV, GRAND MARQUIS FFV, TOWN CAR FFV	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	8FMXV04.6VEF	8FMXR0115GAK		CGNLR0115F28	CGNLV04.6F28	Int Appr
Ford	2008	4.6	FORD CROWN VICTORIA, MERCURY GRAND MARQUIS, LINCOLN TOWN CAR	CNG	Gasoline	NGV Motori	8FMXV04.6VE9, 8FMXV04.6VEF, 8FMXV04.6VE3	8FMXR0115GAK		BNGCR000CNG	BNGCV04.6VE9	Int Appr
Ford	2008	5.4	F-150 4X2, F-150 4X4, MARK-LT 4X2, MARK-LT 4X4, F150 STX SE 4X2	Gasoline/CNG	Gasoline	Auto Gas America	8FMXT05.44HA	8FMXR0240NBR		CAGTR0240NBR	CAGTT05.4D08	Int Appr
Ford	2008	5.4	Ford: F250/F350 trucks	CNG or gasoline	Gasoline	FuelTek Conversion Corp.	8FMXXK05.46RG	8FMXR0250NBS	CFTKE05.46RG-001	CFTKR0250NBS	CFTKE05.46RG	EPA Cert
Ford	2008	5.4	Ford: F250/F350 trucks	CNG or gasoline	Gasoline	FuelTek Conversion Corp.	8FMXXK05.46RG	8FMXE0265GAS	CFTKE05.46RG-002	CFTKE0265GAS	CFTKE05.46RG	EPA Cert
Ford	2008	5.4	Ford: F250/F350 trucks	CNG or gasoline	Gasoline	FuelTek Conversion Corp.	8FMXXK05.46RG	8FMXE0250GAS	CFTKE05.46RG-003	CFTKE0250NBS	CFTKE05.46RG	EPA Cert
Ford	2008	5.4	F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG	Gasoline	Go Natural CNG	8FMXXK05.47RE	8FMXE0120GAS		CGNLF0120F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD BED DELETE, F350 4WD BED DELETE, F350 2WD, F350 4WD	CNG	Gasoline	Go Natural CNG	8FMXXK05.46RG, 8FMXXK05.47RE	8FMXE0250NBS		CGNLF0250F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	E350 CUTAWAY, F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	CNG	Gasoline	Go Natural CNG	8FMXT05.45H2, 8FMXXK05.46RG, 8FMXXK05.46RG, 8FMXXK05.47RE	8FMXE0265GAS		CGNLF0265F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	F150 STX SE 2WD FFV, F150 PICKUP 2WD, F150 PICKUP 4WD, F150 STX SE 2WD, MARK LT, MARK LT 4WD, F150 FFV 2WD, F150 FFV 4WD	CNG	Gasoline/E85	Go Natural CNG	8FMXT05.43HP, 8FMXT05.44HA, 8FMXT05.44HF	8FMXR0240NBR		CGNLR0240F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	CNG	Gasoline	Go Natural CNG	8FMXXK05.46RG	8FMXR0250NBS		CGNLR0250F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	E150 VAN, E250 VAN, E350 CLUB WAGON, E350 VAN, E150 CLUB WAGON, E350 VAN	CNG	Gasoline	Go Natural CNG	8FMXXK05.46R3, 8FMXT05.45H2	8FMXR0265GAS		CGNLR0265F18	CGNLT05.4F18	Int Appr
Ford	2008	5.4	EXPEDITION 2WD, NAVIGATOR 2WD	CNG	Gasoline	Go Natural CNG	8FMXT05.45AB	8FMXR0265NBR		CGNLR0265FA8	CGNLT05.4F18	Int Appr
Ford	2008	5.4	F250 2WD BED DELETE, F250 4WD BED DELETE, F350 2WD BED DELETE, F350 4WD BED DELETE	Gasoline/CNG	Gasoline	Go Natural CNG	8FMXXK05.46RG	8FMXE0250NBS		CGNLF0250F28	CGNLD05.4F28	Int Appr
Ford	2008	5.4	F350 INCOMPLETE 2WD, F350 INCOMPLETE 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	8FMXXK05.46RG, 8FMXXK05.46BG	8FMXE0265GAS		CGNLF0265F28	CGNLD05.4F28	Int Appr
Ford	2008	5.4	F250 PICKUP 2WD, F250 PICKUP 4WD, F350 2WD, F350 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	8FMXXK05.46RG	8FMXR0250NBS		CGNLR0250F28	CGNLD05.4F28	Int Appr

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2008	5.4	E150 VAN, E250 VAN, E350 CLUB WAGON, E350 VAN	Gasoline/CNG	Gasoline	Go Natural CNG	8FMXX05.46R3	8FMXR0265GAS		CGNLR0265F28	CGNLD05.4F28	Int Appr
Ford	2008	5.4	NGV Conversion, Inc.: E-Series Van, complete or incomp	CNG	Gasoline	NGV Conversion, Inc.	8FMXT05.45H2	8FMXR0265GAS; 8FMXE0265GAS	ANGCT05.45H2-001	ANGCR0000CNG	ANGCT05.45H2	EPA Cert
Ford	2008	5.4	NGV Conversion, Inc.: E-Series Van, complete or incomp	CNG	Gasoline	NGV Conversion, Inc.	8FMXT05.45H2	8FMXR0265GAS; 8FMXE0265GAS	BNGCT05.45H2-001	BNGCR0000CNG	BNGCT05.45H2	EPA Cert
Ford	2008	5.4	NGV Conversion, Inc.: E-Series Van, complete or incomp	CNG	Gasoline	NGV Conversion, Inc.	8FMXT05.45H2	8FMXR0265GAS; 8FMXE0265GAS	ANGCT05.45H2-001	ANGCR0000CNG	ANGCT05.45H2	EPA Cert
Ford	2008	6.8	E450	CNG	Gasoline	NGV Motori	8FMXH06.8BST	8FMXE0265GAT		BNGCR00000001	BNGCT06.8NG1	Int Appr
Ford	2008	5.4, 4.6	FORD: E150 CLUB WAGON, E150 VAN, E250 VAN, E350 CLUB WAGON, E350 VAN, E350 CUTAWAY, FORD: F150 PICKUP 2WD, F150 PICKUP 4WD, E250 CUTAWAY, F150 STX SE 2WD; LINCOLN: MARK LT, MARK LT 4WD	Gasoline/CNG	Gasoline	American Alternative Fuel LLC	8FMXT05.45H2, 8FMXT04.63HB, 8FMXT04.65HA, 8FMXT05.44HA	8FMXR0265GAS, 8FMXE0265GAS, 8FMXR0240NBR		CAMAR0265GAS	CAMAT05.48NG	Int Appr
Ford	2007	2.3	FORD RANGER 4X2, MAZDA B2300 4X2	CNG	Gasoline	Go Natural CNG	7FMXT02.31EG	7FMXR0165GBL		DGNLR0165GBL	DGNLT02.3107	Int Appr
Ford	2007	4.0	FORD RANGER 4X2, FORD RANGER 4X4, MAZDA B4000 4X2, MAZDA B4000 4X4	Gasoline/CNG	Gasoline	Auto Gas America	7FMXT04.02EG	7FMXR0165GBL		CAGTR0165GBL	CAGTT04.0007	Int Appr
Ford	2007	5.4	F-150 4X2, F-150 4X4, MARK-LT 4X2, MARK-LT 4X4, F150 STX SE 4X2	Gasoline/CNG	Gasoline	Auto Gas America	7FMXT05.44HA	7FMXR0240NBR		CAGTR0240NBR	CAGTT05.4007	Int Appr
Ford	2006	5.4	E150 CLUB WAGON, E150 ECONOLINE 2WD	CNG	Gasoline	Go Natural CNG	6FMXT05.4RM6	6FMXR0265GAN		CGNLR0265F16	CGNLT05.4F16	Int Appr
Ford	2006	5.4	F150 2WD, F150 4WD	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	6FMXT05.4RH2	6FMXR0240NBN		CGNLR0240F26	CGNLT05.4F26	Int Appr
Ford	2006	5.4	F150 2WD, F150 4WD	Gasoline/E85/CNG	Gasoline/E85	Go Natural CNG	6FMXT05.4RH2	6FMXR0240NBM		CGNLR0240F86	CGNLT05.4F26	Int Appr
Ford	2006	5.4, 4.6	EXPEDITION 2WD, EXPEDITION 4WD, F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SUPERCREW P/U 2WD, F150 SUPERCREW P/U 4WD, NAVIGATOR 2WD, NAVIGATOR 4WD, F150 FFV 2WD, F150 FFV 4WD	CNG	Gasoline	Go Natural CNG	6FMXT05.4R17, 6FMXT04.63HC, 6FMXT05.4RH2	6FMXR0240NBM		CGNLR0240F16	CGNLT05.4F16	Int Appr
Ford	2006	5.4, 4.6	F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SUPERCREW P/U 2WD, F150 SUPERCREW P/U 4WD, MARK LT, F150 FFV 2WD, F150 FFV 4WD	CNG	Gasoline	Go Natural CNG	6FMXT05.4R17, 6FMXT04.63HC, 6FMXT05.4RH2	6FMXR0240NBN		CGNLR0240FA6	CGNLT05.4F16	Int Appr
Ford	2005	5.4	EXPEDITION 2WD, EXPEDITION 4WD, F150 PICKUP 2WD, F150 PICKUP 4WD, NAVIGATOR 2WD, NAVIGATOR 4WD	CNG	Gasoline	Go Natural CNG	5FMXT05.4R17	5FMXR0240NBM		CGNLR0240F15	CGNLT05.4F15	Int Appr
Ford	2005	5.4	F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SUPERCREW P/U 2WD, F150 SUPERCREW P/U 4WD	CNG	Gasoline	Go Natural CNG	5FMXT05.4R17	5FMXR0240NBN		CGNLR0240FA5	CGNLT05.4F15	Int Appr

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
Ford	2005	5.4	EXPEDITION 2WD, EXPEDITION 4WD, F150 PICKUP 2WD, F150 PICKUP 4WD, NAVIGATOR 2WD, NAVIGATOR 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	5FMXT05.4R17	5FMXR0240NBM		CGNLR0240F25	CGNLT05.4F25	Int Appr
Ford	2005	5.4	F150 PICKUP 2WD, F150 PICKUP 4WD, F150 SUPERCREW P/U 2WD, F150 SUPERCREW P/U 4WD	Gasoline/CNG	Gasoline	Go Natural CNG	5FMXT05.4R17	5FMXR0240NBN		CGNLR0240FB5	CGNLT05.4F25	Int Appr
Ford	2005	5.4	E-350 Van	CNG or gasoline	Gasoline	Parnell USA	6FMXT05.4TF5	6FMXE0200GAP	2006-1807LDT-01	6PRLE0200GAP	6PRLT05.4TF5	EPA Cert
Ford	2005	5.4	E-350 Van	CNG or gasoline	Gasoline	Parnell USA	6FMXT05.4TF5	6FMXE0265GAP	2006-1807LDT-02	6PRLE0265GAP	6PRLT05.4TF5	EPA Cert
Ford	2005	5.4	E-350 Van	CNG or gasoline	Gasoline	Parnell USA	6FMXT05.4TF5	6FMXE0200GAP	2006-1807LDT-01	6PRLE0200GAP	6PRLT05.4TF5	EPA Cert
Ford	2005	5.4	E-350 Van	CNG or gasoline	Gasoline	Parnell USA	6FMXT05.4TF5	6FMXE0265GAP	2006-1807LDT-02	6PRLE0265GAP	6PRLT05.4TF5	EPA Cert
General Motors	2014	1.4	IMPCO Automotive - Chevrolet: Chevrolet Cruze	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.		EGMXR0120818	EZ9XV01.4BCE-004	EZ9XR01208CE	EZ9XV01.4BCE	EPA Cert
General Motors	2014	6.0	IMPCO Automotive - Chevrolet: Chev G2500 Express 2WD Cargo, Chev G2500 Express 2WD Pass, Chev G2500 Express 2WD Pass MDPV, Chev G2500 Express Conv 2WD Cargo, Chev G3500 Express 2WD Cargo, Chev G3500 Express 2WD Pass, Chev G3500 Express 2WD Pass MDPV, Chev G3500 Express Conv 2WD Carg IMPCO Automotive - General Motors: GMC G2500 Savana 2WD Cargo, GMC G2500 Savana 2WD Pass, GMC G2500 Savana 2WD Pass (MDPV), GMC G2500 Savana Cnv 2WD Car MDP, GMC G3500 Savana 2WD Cargo, GMC G3500 Savana 2WD Pass, GMC G3500 Savana 2WD Pass (MDPV), GMC G3500 Savana Conv 2WD Cargo	CNG	Gasoline/E85	IMPCO Technologies, Inc.	EGMXT06.0396	EGMXR0223841	EZ9XT06.0CDA-003-R01	EZ9XR00000CDA	EZ9XT06.0CDA	EPA Cert
General Motors	2014	6.0	IMPCO Automotive - Chevrolet: Chev C25 Silverado 2WD, Chev C35 Silverado 2WD, Chev K25 Silverado 4WD, Chev K35 Silverado 4WD IMPCO Automotive - General Motors: GMC C25 Sierra 2WD, GMC C35 Sierra 2WD, GMC K25 Sierra 4WD, GMC K35 Sierra 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	EGMXT06.0396	EGMXR0223841	EZ9XT06.0GF1-001-R01, EO-A-328-0061	EZ9XR0223841	EZ9XT06.0GF1	EPA, CARB
General Motors	2014	6.0	IMPCO Automotive - Chevrolet: Chev C35 Silverado 2WD, Chev K35 Silverado 4WD IMPCO Automotive - General Motors: GMC C35 Sierra 2WD, GMC K35 Sierra 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	EGMXT06.0396	EGMXR0223842	EZ9XT06.0GF1-002, EO-A-328-0061	EZ9XR0223842	EZ9XT06.0GF1	EPA, CARB

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.0	IMPCO Technologies, Inc.: Chev G2500 Express 2WD Cargo, Chev G2500 Express 2WD Cargo MDP, Chev G2500 Express 2WD Pass, Chev G2500 Express 2WD Pass MDPV, Chev G2500 Express Conv 2WD Carg, Chev G3500 Express 2WD Cargo, Chev G3500 Express 2WD Cargo MDP, Chev G3500 Express 2WD Pass, Chev G3500 Express 2WD Pass MDPV, Chev G3500 Express Conv 2WD Carg, GMC G2500 Savana 2WD Cargo, GMC G2500 Savana 2WD Cargo MDPV, GMC G2500 Savana 2WD Pass (MDPV), GMC G2500 Savana Cnv 2WD Car MDP, GMC G3500 Savana 2WD Cargo, GMC G3500 Savana 2WD Cargo MDPV, GMC G3500 Savana 2WD Pass, GMC G3500 Savana 2WD Pass (MDPV), GMC G3500 Savana Conv 2WD Cargo	CNG	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0223841; DGMXR0223842	DZ9XT06.0CDA-005-R01, EO A-328-0057	DZ9XR0000CDA	DZ9XT06.0CDA	EPA, CARB
			IMPCO Technologies, Inc.: Chev C25 Silverado 2WD, Chev C35 Silverado 2WD, Chev C35 Silverado 2WD Long Box, Chev K25 Silverado 4WD, Chev K35 Silverado 4WD Long Box, GMC C25 Silverado 4WD Long Box, GMC C25 Sierra 2WD, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC K25 HD Sierra 4WD, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0223841	DZ9XT06.0GF1-001-R02	DZ9XR0223841	DZ9XT06.0GF1	EPA Cert
			IMPCO Technologies, Inc.: Chev C25 Silverado 2WD, Chev C35 Silverado 2WD, Chev C35 Silverado 2WD Long Box, Chev K25 Silverado 4WD, Chev K35 Silverado 4WD Long Box, GMC C25 Silverado 4WD Long Box, GMC C25 Sierra 2WD, GMC C35 Sierra 2WD, GMC K25 HD Sierra 4WD, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0223841	DZ9XT06.0GF1-001	DZ9XR0223841	DZ9XT06.0GF1	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.0	IMPCO Technologies, Inc.: Chev C35 Silverado 2WD, Chev C35 Silverado 2WD Long Box, Chev K35 Silverado 4WD, Chev K35 Silverado 4WD Long Box, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0223842	DZ9XT06.0GF1-002	DZ9XR0223842	DZ9XT06.0GF1	EPA Cert
General Motors	2013	6	CK20: Chevrolet Silverado 2500HD, GMC Sierra 2500HD; CK30: Chevrolet Silverado 3500HD, GMC Sierra 3500HD; CK31: Chevrolet Silverado 3500 Cab Chassis, GMC Sierra 3500 Cab Chassis; G30: Chevrolet Express Commercial Cutaway 3500, GMC Savana Special Cutaway 3500; Isuzu NPR Workhorse Custom Chassis P30; Freightliner Chassis MT45	CNG	Gasoline	Landi Renzo USA Corporation		DLDR06.0C11	EO-A-400-0008	DLDRF0000000		CARB
General Motors	2013	5.3, 4.8	IMPCO Automotive - Chevrolet: Chev C15 Silverado 2WD, Chev C15 Silverado 2WD XFE, Chev C1500 Tahoe 2WD, Chev K15 Silverado 4WD, Chev K1500 Tahoe 4WD IMPCO Automotive - General Motors: GMC C15 Sierra 2WD, GMC C1500 Yukon 2WD, GMC C15Sierra 2WD XFE, GMC K15 Sierra 4WD, GMC K1500 Yukon 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT05.3381	DGMXR0176820	DZ9XT05.38C1-008-R01	DZ9XR01768C3	DZ9XT05.38C1	EPA Cert
General Motors	2013	5.3, 4.8	IMPCO Automotive - Chevrolet: Chev G1500 Express 2WD Cargo, Chev G1500 Express Conv 2WD Carg, Chev H1500 Express AWD Cargo, Chev H1500 Express AWD Pass, Chev H1500 Express Conv AWD Carg, G1500 Express 2WD Pass IMPCO Automotive - General Motors: GMC G1500 Savana 2WD Cargo, GMC G1500 Savana 2WD Pass, GMC G1500 Savana Conv 2WD Cargo, GMC H1500 Savana AWD Cargo, GMC H1500 Savana AWD Pass, GMC H1500 Savana Conv AWD Cargo	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT05.3381	DGMXR0223610	DZ9XT05.38C1-009-R01	DZ9XR02238C1	DZ9XT05.38C1	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	5.3, 4.8	IMPCO Automotive - Chevrolet: Chev C15 Silverado 2WD, Chev C1500 Avalanche 2WD, Chev C1500 Suburban 2WD, Chev K15 Silverado 4WD, Chev K1500 Avalanche 4WD, Chev K1500 Suburban 4WD IMPCO Automotive - General Motors: GMC C15 Sierra 2WD, GMC C1500 Yukon XL 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon XL 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT05.3381	DGMXR0223840	DZ9XT05.3BC1-010-R01	DZ9XR02238C3	DZ9XT05.3BC1	EPA Cert
General Motors	2013	5.3, 4.8	IMPCO Automotive - Chevrolet: Chev C15 Silverado 2WD, Chev C15 Silverado 2WD XFE, Chev C1500 Tahoe 2WD, Chev K15 Silverado 4WD, Chev K1500 Tahoe 4WD IMPCO Automotive - General Motors: GMC C15 Sierra 2WD, GMC C1500 Yukon 2WD, GMC C15 Sierra 2WD XFE, GMC K15 Sierra 4WD, GMC K1500 Yukon 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT05.3373	DGMXR0176820	DZ9XT05.3BC3-006-R01	DZ9XR01768C3	DZ9XT05.3BC3	EPA Cert
General Motors	2013	5.3, 4.8	IMPCO Automotive - Chevrolet: Chev C15 Silverado 2WD, Chev C1500 Avalanche 2WD, Chev K15 Silverado 4WD, Chev K1500 Avalanche 4WD, Chev K1500 Suburban 4WD IMPCO Automotive - General Motors: GMC C15 Sierra 2WD, GMC C1500 Yukon XL 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon XL 4WD	CNG or gasoline	Gasoline/E85	IMPCO Technologies, Inc.	DGMXT05.3373	DGMXR0223840	DZ9XT05.3BC3-007	DZ9XR02238C3	DZ9XT05.3BC3	EPA Cert
General Motors	2013	6.0, 4.8	IMPCO Technologies, Inc.: Chev C35 Silverado 2WD, Chev C35 Silverado 2WD Long Box, Chev K35 Silverado 4WD, Chev K35 Silverado 4WD Long Box, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0223842	DZ9XT06.0GFD-003	DZ9XR0223842	DZ9XT06.0GFD	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.0, 4.8	IMPCO Technologies, Inc.: Chev C25 Silverado 2WD, Chev C35 Silverado 2WD, Chev C35 Silverado 2WD Long Box, Chev G2500 Express 2WD Cargo, Chev G2500 Express 2WD Pass, Chev G2500 Express 2WD Pass MDPV, Chev G2500 Express Conv 2WD Carg, Chev G3500 Express 2WD Cargo, Chev G3500 Express 2WD Pass, Chev G3500 Express 2WD Pass MDPV, Chev K25 Express Conv 2WD Carg, Chev K25 Silverado 4WD, Chev K35 Silverado 4WD, Chev K35 Silverado 4WD Long Box, GMC C25 Sierra 2WD, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC G2500 Savana 2WD Cargo, GMC G2500 Savana 2WD Pass, GMC G2500 Savana 2WD Pass (MDPV), GMC G2500 Savana Cnv 2WD Car MDP, GMC G3500 Savana 2WD Cargo, GMC G3500 Savana 2WD Pass, GMC G3500 Savana 2WD Pass (MDPV), GMC G3500 Savana Conv 2WD Cargo, GMC K25 HD Sierra 4WD, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	DGMXT06.0396	DGMXR0233841	DZ9XT06.0GFD-004	DZ9XR0223841	DZ9XT06.0GFD	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.0, 4.8	NatGasCar: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SIERRA 2WD LONG BOX, C35 SILVERADO 2WD, C35 SILVERADO 2WD LONG BOX, C35 SILVERADO CREW CAB 2WD, G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD CARGO MDPV, G2500 EXPRESS 2WD PASS, G2500 EXPRESS 2WD PASS MDPV, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD CARGO MDPV, G2500 SAVANA 2WD PASS, G2500 SAVANA 2WD PASS (MDPV), G2500 SAVANA CONV 2WD CARGO, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD CARGO MDPV, G3500 EXPRESS 2WD PASS, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD CARGO MDPV, G3500 SAVANA 2WD PASS, G3500 SAVANA 2WD PASS (MDPV), G3500 SAVANA CONV 2WD CARGO, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SIERRA 4WD LONG BOX, K35 SILVERADO 4WD, K35 SILVERADO 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CGMXT06.0396	CGMXR0223841	CNATT06.0396-017-R01	CNATR0223841	CNATT06.0396	EPA Cert
	2013	6.0, 4.8	NatGasCar: C35 SIERRA 2WD, C35 SIERRA 2WD LONG BOX, C35 SILVERADO 2WD, C35 SILVERADO 2WD LONG BOX, C35 SILVERADO CREW CAB 2WD, K35 SIERRA 4WD, K35 SIERRA 4WD LONG BOX, K35 SILVERADO 4WD, K35 SILVERADO 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	CGMXT06.0396	CGMXR0223842	CNATT06.0396-018-R01	CNATR0223842	CNATT06.0396	EPA Cert
	2013	6.0, 4.8	NatGasCar: C35 SIERRA 2WD, C35 SIERRA 2WD LONG BOX, C35 SILVERADO 2WD, C35 SILVERADO 2WD LONG BOX, K35 SIERRA 4WD, K35 SIERRA 4WD LONG BOX, K35 SILVERADO 4WD, K35 SILVERADO 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	DGMXT06.0396	DGMXR0223842	DNATT06.0396-001-R01	DNATR0223842	DNATT06.0396	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.0, 4.8	NatGasCar: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SIERRA 2WD LONG BOX, C35 SILVERADO 2WD, C35 SILVERADO 2WD LONG BOX, G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD PASS, G2500 EXPRESS 2WD PASS MDPV, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD PASS, G2500 SAVANA 2WD PASS (MDPV), G2500 SAVANA 2WD CARGO MDPV, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD PASS, G3500 EXPRESS 2WD PASS MDPV, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD PASS (MDPV), G3500 SAVANA 2WD CARGO, G25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SIERRA 4WD LONG BOX, K35 SILVERADO 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	Nat Gas Car LLC	DGMXT06.0396	DGMXR0223841	DNATT06.0396-002-R01	DNATR0223841	DNATT06.0396	EPA Cert
			Auto Gas America: Chevrolet C35 SILVERADO 2WD, Chevrolet K35 SILVERADO 4WD, Chevy C35 SILVERADO 2WD LONG BOX, Chevy K35 SILVERADO 4WD LONG BOX, GMC C35 SIERRA 2WD, GMC C35 SIERRA 2WD LONG BOX, GMC K35 SIERRA 4WD, GMC K35 SIERRA 4WD LONG BOX	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	DGMXT06.0396	DGMXR0223842	DAGTT06.0396-002-R01	DAGTR0223842	DAGTT06.0396	EPA Cert
			Auto Gas America: Cadillac ESCALADE 2WD, Cadillac ESCALADE AWD, Chevrolet C15 SILVERADO 2WD, Chevrolet C15 Silverado 2WD XFE, Chevrolet C1500 TAHOE 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA 2WD XFE, GMC C1500 YUKON 2WD, GMC K15 SIERRA 4WD, GMC K15 SIERRA AWD, GMC K1500 YUKON 4WD, GMC K1500 YUKON DENALI AWD	CNG or gasoline	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	DGMXT06.2375	DGMXR0176820	DAGTT06.2375-003-R01	DAGTR0176820	DAGTT06.2375	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2013	6.2, 5.3, 4.8	Auto Gas America: Cadillac ESCALADE ESV 2WD, Cadillac ESCALADE ESV AWD, Cadillac ESCALADE EXT AWD, Chevrolet C15 SILVERADO 2WD, Chevrolet C1500 AVALANCHE 2WD, Chevrolet C1500 SUBURBAN 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD, GMC K1500 YUKON XL AWD	CNG or gasoline	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	DGMXT06.2375	DGMXR0223840	DAGTT06.2375-004-R01	DAGTR0223840	DAGTT06.2375	EPA Cert
			CK20, Silverado 2500, Silverado 2500HD, GMC Sierra 2500, GMC Sierra 2500HD, CK30, Silverado 3500, Silverado 3500 Cab Chassis, Sierra 3500, Sierra 3500 Cab Chassis, Express Cutaway 3500, Savana Cutaway 3500, Freightliner MT45 Chassis, Workhorse Custom Chassis P30, Bremach, Isuzu NPR	CNG	Gasoline	Baytech Corporation			EO A-330-0235	CBYTF0000000		CARB
General Motors	2012	6.0	IA Dedicated CNG - GM: G2500 Express 2WD Cargo, G2500 Express 2WD Cargo MDPV, G2500 Express 2WD Pass, G2500 Express 2WD Pass MDPV, G2500 Express Conv 2WD Cargo, G2500 Savana 2WD Cargo, G2500 Savana 2WD Cargo MDPV, G2500 Savana 2WD Pass MDPV, G2500 Savana Conv 2WD Cargo, G3500 Express 2WD Cargo, G3500 Express 2WD Cargo MDPV, G3500 Express 2WD Pass, G3500 Express Conv 2WD MDPV, G3500 Express CONV 2WD Cargo, G3500 Savana 2WD Cargo, G3500 Savana 2WD Cargo MDPV, G3500 Savana 2WD Pass, G3500 Savana 2WD Pass MDPV, G3500 Savana Conv 2WD Cargo	CNG	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT06.0396	CGMXR023841; CGMXR0223842	CZ9XT06.0CDA-006	CZ9XR00000CDA	CZ9XT06.0CDA	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	5.3, 4.8	CNG Interstate, LLC: Chevrolet C15 SILVERADO 2WD, Chevrolet C1500 AVALANCHE 2WD, Chevrolet C1500 SUBURBAN 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 AVALANCHE 4WD, Chevrolet K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON WL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline	Gasoline/E85	CNG Interstate, LLC	CGMXT05.3373	CGMXR0223840	DCNST05.3373-001	DCNSR0223840	DCNST05.3373	EPA Cert
			CNG Interstate, LLC: Chevrolet C15 SILVERADO 2WD, Chevrolet C15 SILVERADO 2WD XFE, Chevrolet C15 Silverado 2WD, Chevrolet C1500 TAHOE 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SILVERADO 2WD XFE, GMC C1500 YUKON 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD	CNG or gasoline	Gasoline/E85	CNG Interstate, LLC	CGMXT05.3373	CGMXR0176820	DCNST05.3373-002	DCNSR0176820	DCNST05.3373	EPA Cert
General Motors	2012	5.3, 4.8	IA Bi-Fuel CNG - GM: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C15 SILVERADO 2WD XFE, CHEVROLET C1500 TAHOE 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA 2WD XFE, GMC C1500 YUKON 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT05.3373	CGMXR0176820	CZ9XT05.3GFC-007	CZ9XR0176GFC	CZ9XT05.3GFC	EPA Cert
			IA Bi-Fuel CNG - GM: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C1500 AVALANCHE 2WD, CHEVROLET K15 SUBURBAN 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 AVALANCHE 4WD, CHEVROLET K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT05.3373	CGMXR0223840	CZ9XT05.3GFC-008	CZ9XR0223G2C	CZ9XT05.3GFC	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	5.3, 4.8	IMPCO Technologies, Inc.: Chev C15 Silverado 2WD, Chev C15 Silverado 2WD XFE, Chev C1500 Tahoe 2WD, Chev K15 Silverado 4WD, Chev K1500 Tahoe 4WD, GMC C15 Sierra 2WD, GMC C15 Sierra 2WD XFE, GMC C1500 Yukon 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT05.3381	CGMXR0176820	CZ9XT05.3G2C-023	CZ9XR0176GFC	CZ9XT05.3G2C	EPA Cert
General Motors	2012	5.3, 4.8	IMPCO Technologies, Inc.: Chev G1500 Express 2WD Cargo, Chev G1500 Express 2WD Pass, Chev G1500 Express Conv 2WD Carg, Chev H1500 Express AWD Cargo, Chev H1500 Express AWD Pass, Chev H1500 Express Conv AWD Carg, GMC G1500 Savana 2WD Cargo, GMC G1500 Savana 2WD Pass, GMC G1500 Savana Conv 2WD Cargo, GMC H1500 Savana AWD Cargo, GMC H1500 Savana AWD Pass, GMC H1500 Savana Conv AWD Cargo	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT05.3381	CGMXR0223610	CZ9XT05.3G2C-024	CZ9XR0223GFC	CZ9XT05.3G2C	EPA Cert
General Motors	2012	5.3, 4.8	IMPCO Technologies, Inc.: Chev C15 Silverado 2WD, Chev C1500 Avalanche 2WD, Chev C1500 Suburban 2WD, Chev K15 Silverado 4WD, Chev K1500 Avalanche 4WD, Chev K1500 Suburban 4WD, GMC C15 Sierra 2WD, GMC C1500 Yukon XL 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon XL 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT05.3381	CGMXR0223840	CZ9XT05.3G2C-025	CZ9XR0223G2C	CZ9XT05.3G2C	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	6.0, 4.8	IA Dedicated CNG - GM: C15 Silverado 2WD XFE, C25 Silverado 2WD, C35 Sierra 2WD, C35 Silverado 2WD, C35 Silverado 2WD Long Box, C35 Silverado Crew Cab 2WD, G2500 Express 2WD Cargo, G2500 Express 2WD Cargo MDPV, G2500 Express 2WD Pass, G2500 Express 2WD Pass MDPV, G2500 Express Conv 2WD Cargo, G2500 Savana 2WD Pass, G2500 Savana 2WD Cargo, G2500 Savana 2WD Cargo MDPV, G2500 Savana 2WD Pass MDPV, G2500 Savana Conv 2WD Cargo, G3500 Express 2WD Cargo, G3500 Express 2WD Cargo MDPV, G3500 Express 2WD Pass, G3500 Express 2WD Pass MDPV, G3500 Express CONV 2WD Cargo, G3500 Savana 2WD Cargo, G3500 Savana 2WD Cargo MDPV, G3500 Savana 2WD Pass, G3500 Savana 2WD Pass MDPV, G3500 Savana Conv 2WD Cargo, K15 Silverado 4WD, K25 HD Sierra 4WD, K35 Sierra 4WD K35 Silverado 4WD, K35 Sierra 4WD Long Box, K35 Silverado 4WD, K35 Silverado 4WD Long Box	CNG	Gasoline	IMPCO Technologies, Inc.	CGMXT06.0396	CGMXR0223841; CGMXR0223842	CZ9XT06.0CDE-027	CZ9XR0000CDE	CZ9XT06.0CDE	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	6.0, 4.8	IMPCO Technologies, Inc.: Chev C35 Silverado 2WD Long Box, Chev C35 Silverado Crew Cab 2WD, Chev G2500 Exp 2WD Cargo MDPV, Chev G2500 Express 2WD Carg, Chev G2500 Express 2WD Pass, Chev G2500 Express 2WD Pass MDPV, Chev G2500 Express Conv 2WD Carg, Chev G3500 Express 2WD Carg, Chev G3500 Express 2WD Carg MDPV, Chev G3500 Express 2WD Pass MDPV, Chev K35 Silverado 4WD Long Box, Chevrolet C25 Silverado 2WD, Chevrolet C35 Silverado 2WD, Chevrolet G3500 Express 2WD Pass, Chevrolet K25 Silverado 4WD, Chevrolet K35 Silverado 4WD, GMC C25 Sierra 2WD, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC G2500 Savana 2WD Cargo, GMC G2500 Savana 2WD Cargo MDPV, GMC G2500 Savana 2WD Pass, GMC G2500 Savana 2WD Pass (MDPV), GMC G2500 Savana Conv 2WD Cargo, GMC G3500 Savana 2WD Cargo, GMC G3500 Savana 2WD Cargo MDPV, GMC G3500 Savana 2WD Pass, GMC G3500 Savana 2WD Pass (MDPV), GMC K25 HD Sierra 4WD, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT06.0396	CGMXR0223841	CZ9XT06.0GFC-018	CZ9XR0223GFC	CZ9XT06.0GFC	EPA Cert
			IMPCO Technologies, Inc.: Chev C35 Silverado 2WD Long Box, Chev C35 Silverado Crew Cab 2WD, Chev K35 Silverado 4WD Long Box, Chevrolet C35 Silverado 2WD, Chevrolet K35 Silverado 4WD, GMC C35 Sierra 2WD, GMC C35 Sierra 2WD Long Box, GMC K35 Sierra 4WD, GMC K35 Sierra 4WD Long Box	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	CGMXT06.0396	CGMXR0223842	CZ9XT06.0GFC-019	CZ9XR0223G4C	CZ9XT06.0GFC	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	6.0, 4.8	Auto Gas America: Chevrolet C25 Silverado 2WD, Chevrolet G2500 EXPRESS 2WD CARG, Chevrolet G2500 EXPRESS 2WD PASS, Chevrolet G3500 EXPRESS 2WD CARG, Chevrolet K25 SILVERADO 4WD, Chevrolet K35 SILVERADO 4WD, Chevy C35 SILVERADO 2WD LONG BOX, Chevy G2500 EXPRESS 2WD CARGO MD, Chevy G2500 EXPRESS 2WD PAS MDPV, Chevy G2500 EXPRESS CONV CRGO MD, Chevy G3500 EXPRESS 2WD CARGO MD, Chevy G3500 EXPRESS 2WD PASS, Chevy G3500 EXPRESS 2WD PASS MDP, Chevy G3500 EXPRESS CONV CARGO, Chevy K35 SILVERADO 4WD LONG BOX, GMC C25 SIERRA 2WD, GMC C35 SIERRA 2WD, GMC G25 SAVANA 2WD PASS MDPV, GMC G2500 SAVANA 2WD CARGO, GMC G2500 SAVANA 2WD CARGO MDPV, GMC G2500 SAVANA 2WD PASS, GMC G2500 SAVANA CONV CARGO MDPV, GMC G35 SAVANA 2WD PASS MDPV, GMC G3500 SAVANA 2WD PASS, GMC G3500 SAVANA 2WD CARGO, GMC G3500 SAVANA 2WD CARGO MDPV, GMC G3500 SAVANA CONV 2WD CARGO, GMC K25 HD SIERRA 4WD, GMC K35 SIERRA 4WD, GMC K35 SIERRA 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	DGMXT06.0396	DGMXR0223841	DAGTT06.0396-001-R01	DAGTR0223841	DAGTT06.0396	EPA Cert
			Auto Gas America: Chevrolet C35 SILVERADO 2WD, Chevrolet K35 SILVERADO 4WD, Chevy C35 SILVERADO 2WD LONG BOX, Chevy K35 SILVERADO 4WD LONG BOX, GMC C35 SIERRA 2WD, GMC C35 SIERRA 2WD LONG BOX, GMC K35 SIERRA 2WD LONG BOX, GMC K35 SIERRA 4WD, GMC K35 SIERRA 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	CGMXT06.0396	CGMXR0223842	CAGTT06.0397-006	CAGTR0223842	CAGTT06.0397	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	6.0, 4.8	Auto Gas America: 2011 Chevrolet G3500 Express 2WD, Chevrolet C25 Silverado 2WD, Chevrolet G2500 EXPRESS 2WD CARG, Chevrolet G2500 EXPRESS 2WD PASS, Chevrolet K25 EXPRESS 2WD CARG, Chevrolet K25 SILVERADO 4WD, Chevrolet K35 SILVERADO 4WD, Chevy C35 SILVERADO 2WD LONG BOX, Chevy G2500 EXPRESS 2WD CARGO MD, Chevy G2500 EXPRESS 2WD PAS MDPV, Chevy G2500 EXPRESS CONV CRGO MD, Chevy G3500 EXPRESS 2WD PASS, Chevy G3500 EXPRESS 2WD PASS MDP, Chevy G3500 EXPRESS CONV CARGO, Chevy K35 SILVERADO 4WD LONG BOX, GMC C25 SIERRA 2WD, GMC C35 SIERRA 2WD, GMC G25 SAVANA 2WD PASS MDPV, GMC G2500 SAVANA 2WD CARGO, GMC G2500 SAVANA 2WD CARGO MDPV, GMC G2500 SAVANA 2WD PASS, GMC G2500 SAVANA CONV CARGO MDPV, GMC G35 SAVANA 2WD PASS MDPV, GMC G3500 SAVANA 2WD PASS, GMC G3500 SAVANA 2WD CARGO, GMC G3500 SAVANA 2WD CARGO MDPV, GMC G3500 SAVANA CONV 2WD CARGO, GMC K25 HD SIERRA 4WD, GMC K35 SIERRA 4WD, GMC K35 SIERRA 4WD LONG BOX	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	CGMXT06.0396	CGMXR0223841	CAGTT06.0397-007	CAGTR0223841	CAGTT06.0397	EPA Cert
			Auto Gas America: Cadillac ESCALADE 2WD, Cadillac ESCALADE AWD, Chevrolet C15 SILVERADO 2WD, Chevrolet C15 Silverado 2WD XFE, Chevrolet C1500 TAHOE 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA 2WD XFE, GMC C1500 YUKON 2WD, GMC K15 SIERRA 4WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD, GMC K1500 YUKON DENALI AWD									
General Motors	2012	6.2, 5.3, 4.8										

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2012	6.2, 5.3, 4.8	Auto Gas America: Chevrolet G1500 EXPRESS 2WD PASS, Chevrolet H1500 EXPRESS AWD PASS, Chevy G1500 EXPRESS 2WD Cargo, Chevy H1500 EXPRESS AWD Cargo, G1500 EXPRESS CONV 2WD CARGO, GMC G1500 SAVANA 2WD CARGO CONV, GMC G1500 SAVANA 2WD PASS, GMC G1500 Savana 2WD CARGO, GMC H1500 SAVANA AWD CARGO, GMC H1500 SAVANA AWD CARGO CONV, GMC H1500 SAVANA AWD PASS, H1500 EXPRESS CONV AWD CARGO	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	CGMXT05.3381	CGMXR0223610	CAGTT06.2375-004	CAGTR0223610	CAGTT06.2375	EPA Cert
General Motors	2012	6.2, 5.3, 4.8	Auto Gas America: Cadillac ESCALADE ESV 2WD, Cadillac ESCALADE ESV AWD, Cadillac ESCALADE EXT AWD, Chevrolet C15 SILVERADO 2WD, Chevrolet C1500 AVALANCHE 2WD, Chevrolet C1500 SUBURBAN 2WD, Chevrolet K15 SILVERADO 4WD, Chevrolet K1500 AVALANCHE 4WD, Chevrolet K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON AWD, GMC K1500 YUKON XL 4WD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	CGMXT06.2375; CGMXT06.2374; CGMXT05.3373; CGMXT05.3381	CGMXR0223840	CAGTT06.2375-005	CAGTR0223840	CAGTT06.2375	EPA Cert
General Motors	2011	6.0	CK20, Silverado 2500, Silverado 2500HD, GMC Sierra 2500, GMC Sierra 2500HD, CK30, Silverado 3500, Silverado 3500 Cab Chassis, Sierra 3500, Sierra 3500 Cab Chassis, Express Cutaway 35000, Savana Cutaway 3500, Freightliner MT45 Chassis, Workhorse Custom Chassis P30, Bremach, Isuzu NPR	CNG	Gasoline	Baytech Corporation			EO A-330-0229-1	BBYTF0000000	BBYTE06.0613	CARB
General Motors	2011	6.0	IMPCO Technologies, Inc.: CHEVROLET C35 SILVERADO 2WD, CHEVROLET K35 SILVERADO 4WD, GMC C35 SIERRA 2WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	BGMXT06.0396	BGMXR0223842	BZ9XT06.0GFB-033	BZ9XR0223G2B	BZ9XT06.0GFB	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2011	6.0	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET G3500 EXPRESS 2WD PASS, CHEVROLET K25 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC K25 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	BGMXT06.0396	BGMXR0223841	BZ9XT06.0GFB-034	BZ9XR0223GFB	BZ9XT06.0GFB	EPA Cert
General Motors	2011	6.0	Landi Renzo USA: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, G3500 EXPRESS 2WD PASS VAN, K25 SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG	Gasoline	Landi Renzo USA Corporation	BGMXT06.0396	BGMXR0223841; BGMXR0223842	BLDRT06.0B16-002	BLDRR0000000	BLDRT06.0B16	EPA Cert
General Motors	2011	6.0	Auto Gas America: 2011 Chevrolet C25 Silverado 2WD, 2011 Chevrolet G3500 Express 2WD, 2011 Chevrolet K25 Silverado 4WD, 2011 GMC C25 Sierra 2WD, 2011 GMC K25 Sierra 4WD	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	BGMXT06.0396	BGMXR0223841	CAGTT06.0396-001	CAGTR0223841	CAGTT06.0396	EPA Cert
General Motors	2011	6.0	Auto Gas America: 2011 Chevrolet C35 Silverado 2WD, 2011 Chevrolet K35 Silverado 4WD, 2011 GMC C35 Sierra 2WD, 2011 GMC K35 Sierra 4WD	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	BGMXT06.0396	BGMXR0223842	CAGTT06.0396-002	CAGTR0223842	CAGTT06.0396	EPA Cert
General Motors	2011	3.9, 3.5	CNG - Dedicated GM: Buick Lucerne, Chevrolet Impala	CNG	Gasoline/E85	EvoTek LLC	BGMXV03.9055	BGMXR0133810	BETKV03.9N1A-004	BETKR0000E1E	BETKV03.9N1A	EPA Cert
General Motors	2011	3.9, 3.5	NaturalDrive Partners: Impala, Lucerne	CNG	Gasoline/E85	NaturalDrive Partners, LLC	BGMXV03.9055	BGMXR0133810	CNTDV03.905B-002	CNTDR0000000	CNTDV03.905B	EPA Cert
General Motors	2011	4.8, 5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C1500 AVALANCHE 2WD, CHEVROLET C1500 SUBURBAN 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 AVALANCHE 4WD, CHEVROLET K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	BGMXT05.3373	BGMXR0223840	BZ9XT05.3GFB-037	BZ9XR0223G6B	BZ9XT05.3GFB	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2011	4.8, 5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C15 SILVERADO XFE 2WD, CHEVROLET C1500 TAHOE 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA XFE 2WD, GMC C1500 YUKON 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	BGMXT05.3373	BGMXR0176820	BZ9XT05.3GFB-035	BZ9XR0176GFB	BZ9XT05.3GFB	EPA Cert
			IMPCO Technologies, Inc.: CHEV G1500 EXPRESS CONV 2WD CARG, CHEV H1500 EXPRESS CONV AWD CARG, Chevrolet G1500 EXPRESS 2WD CARG, Chevrolet G1500 EXPRESS 2WD PASS, Chevrolet H1500 EXPRESS AWD CARG, Chevrolet H1500 EXPRESS AWD PASS, GMC G1500 SAVANA 2WD CARGO, GMC G1500 SAVANA 2WD PASS, GMC G1500 SAVANA CONV 2WD CARGO, GMC H1500 SAVANA 2WD CARGO, GMC H1500 SAVANA AWD CARGO, GMC H1500 SAVANA AWD CARGO CONV, GMC H1500 SAVANA AWD PASS	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	BGMXT05.3373	BGMXR0223610	BZ9XT05.3GFB-036	BZ9XR0223G4B	BZ9XT05.3GFB	EPA Cert
			NTD 2: G1500 Savana 2WD Cargo NaturalDrive Partners: C15 Sierra 2WD, C15 Sierra XFE 2WD, C15 Silverado 2WD, C15 Silverado XFE 2WD, C1500 Avalanche 2WD, C1500 Suburban 2WD, C1500 Tahoe 2WD, C1500 Yukon 2WD, C1500 Yukon XL 2WD, G1500 Express 2WD Pass, G1500 Savana 2WD Cargo Conv, G1500 Savana 2WD Pass, G1500 Van 2WD Cargo, G1500 Van Conv 2WD Cargo, H1500 Express AWD Pass, H1500 Savana AWD Cargo Conv, H1500 Savana Cargo AWD, H1500 Savana Pass Van AWD, H1500 Van AWD Cargo, H1500 Van Conv AWD Cargo, K15 Sierra 4WD, K15 Silverado 4WD, K1500 Avalanche 4WD, K1500 Suburban 4WD, K1500 Tahoe 4WD, K1500 Yukon 4WD, K1500 Yukon XL 4WD	CNG	Gasoline/E85	NaturalDrive Partners, LLC	BGMXT05.3373; BGMXT05.3381	BGMXR0176820; BGMXR0223610; BGMXR0223840	BNTDT05.3FEB-005	BNTDR0000010	BNTDT05.3FEB	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2011	6.0, 4.8	Baytech Corporation: G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD PASS, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD PASS, G2500 SAVANA CONV 2WD CARGO, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD PASS, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD PASS, G3500 SAVANA CONV 2WD CARGO	CNG	Gasoline/E85	Baytech Corporation	BGMXT06.0398	BGMXR0223841	BBYTT06.0918-009	BBYTE0000000	BBYTT06.0918	EPA Cert, CARB
	2011	6.0, 4.8	Greenkraft Inc.: C25 SIERRA 2WD, C25 SILVERADO 2WD, C2500 SUBURBAN 2WD, C2500 YUKON XL 2WD, G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD CARGO MDPV, G2500 EXPRESS 2WD PASS, G2500 EXPRESS 2WD PASS MDPV, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD CARGO MDPV, G2500 SAVANA 2WD PASS, G2500 SAVANA 2WD PASS MDPV, G2500 SAVANA CONV 2WD CARGO, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD CARGO MDPV, G3500 EXPRESS 2WD PASS, G3500 EXPRESS 2WD PASS MDPV, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD CARGO MDPV, G3500 SAVANA 2WD PASS, G3500 SAVANA 2WD PASS MDPV, G3500 SAVANA CONV 2WD CARGO, GMC, K25 SIERRA 4WD, K25 SILVERADO 4WD, K2500 SUBURBAN 4WD, K2500 YUKON XL 4WD	CNG	Gasoline/E85	Greenkraft Inc.	BGMXT06.0398; BGMXT06.0396; BGMXT06.0395	BGMXR0223841; BGMXR0223842; BGMXR0260843	BGKTT06.0GM1-001	BGKTV0006GM1	BGKTT06.0GM1	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2011	6.0, 4.8	NTD 2: G2500 Express 2WD Pass, G2500 SAVANA 2WD CARGO MDPV, G2500 Savana 2WD Pass NaturalDrive Partners: G2500 EXPRESS 2WD CARGO MDPV, G2500 EXPRESS 2WD PASS MDPV, G2500 Express 2WD Cargo, G2500 Express Conv 2WD Cargo, G2500 SAVANA 2WD PASS MDPV, G2500 Savana 2WD Cargo, G2500 Savana Conv 2WD Cargo, G3500 EXPRESS 2WD CARGO MDPV, G3500 EXPRESS 2WD PASS MDPV, G3500 Express 2WD Cargo, G3500 Express 2WD Pass, G3500 Express Conv 2WD Cargo, G3500 SAVANA 2WD CARGO MDPV, G3500 SAVANA 2WD PASS MDPV, G3500 Savana 2WD Cargo, G3500 Savana 2WD Pass, G3500 Savana Conv 2WD Cargo	CNG	Gasoline/E85	NaturalDrive Partners, LLC	BGMXT06.0398	BGMXR0223841	BNTDT06.0VAB-003-R01	BNTDR0000008	BNTDT06.0VAB	EPA Cert, CARB
			Auto Gas America: Cadillac Escalade 2WD, Cadillac Escalade AWD, Chevrolet C15 Silverado 2WD, Chevrolet C15 Silverado 2WD XFE, Chevrolet C1500 Tahoe 2WD, Chevrolet K15 Silverado 4WD, Chevrolet K1500 Tahoe 4WD, GMC C15 Sierra 2WD, GMC C15 Sierra 4WD, GMC K15 Sierra AWD, GMC K1500 Yukon 4WD, GMC K1500 Yukon Denali AWD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	BGMXT05.3373; BGMXT06.2375	BGMXR0176820	BAGTT06.237B-007	BAGTR0176820	BAGTT06.237B	EPA Cert
General Motors	2011	6.2, 5.3, 4.8	Auto Gas America: Chevrolet G1500 Express 2WD Pass, Chevrolet G1500 Van 2WD Cargo, Chevrolet G1500 Express Conv 2WD, Chevrolet H1500 Express AWD Pass, Chevrolet H1500 Van AWD Cargo, Chevrolet H1500 Van Conv AWD, GMC G1500 Savana 2WD Cargo, GMC G1500 Savana 2WD Cargo Conv, GMC G1500 Savana 2WD Pass, GMC H1500 Savana AWD Cargo Conv, GMC H1500 Savana AWD Pass, GMC H1500 Savana Cargo AWD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	BGMXT05.3373	BGMXR0223610	BAGTT06.237B-008	BAGTR0223610	BAGTT06.237B	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2011	6.2, 5.3, 4.8	Auto Gas America: Cadillac Escalade ESV 2WD, Cadillac Escalade ESV AWD, Cadillac Escalade EXT AWD, Chevrolet C1500 Avalanche 2WD, Chevrolet C1500 Suburban 2WD, Chevrolet K15 Silverado 4WD, Chevrolet K1500 Suburban 4WD, GMC C15 Sierra 2WD, GMC C1500 Yukon XL 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon AWD, GMC K1500 Yukon XL 4WD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas America	BGMXT05.3373; BGMXT06.2375	BGMXR0223840	BAGTT06.237B-009	BAGTR0223840	BAGTT06.237B	EPA Cert
General Motors	2010	6.0	CK20, Silverado 2500, Silverado 2500HD, GMC Sierra 2500, GMC Sierra 2500HD, CK30, Silverado 3500, Silverado 3500 Cab Chassis, Sierra 3500, Sierra 3500 Cab Chassis, Express Cutaway 35000, Savana Cutaway 3500, Workhorse Custom Chassis P30, Isuzu NPR, Chevrolet W3500, GMC W3500	CNG	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0176821; AGMXR0223841; AGMXR0223842	EO A-330-0226	ABYTF0000000		CARB
General Motors	2010	6.0	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0176821; AGMXR0176821; AGMXR0223841	ABYTD06.0816-001-R01	ABYTE0000000	ABYTD06.0816	EPA Cert, CARB
General Motors	2010	6.0	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG	Gasoline	Baytech Corporation	AGMXD06.0396		BBYTD06.0116-005	BBYTE0000000	BBYTD06.0116	EPA Cert
General Motors	2010	6.0	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0223842	ABYTD06.0826-003	ABYTR0223826	ABYTD06.0826	EPA Cert
General Motors	2010	6.0	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0176821	ABYTD06.0826-004	ABYTR0176826	ABYTD06.0826	EPA Cert
General Motors	2010	6.0	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0223841	ABYTD06.0826-005	ABYTR0223846	ABYTD06.0826	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2010	6.0	CNG - Dedicated GM: GM 6.0L MD Truck	CNG	Gasoline	EvoTek LLC	AGMXD06.0396	AGMXR0176821; AGMXR0223841; AGMXR0223842	AETKD06.0N1A-005	AETKR0000N1E	AETKD06.0N1A	EPA Cert
General Motors	2010	6.0	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET K25 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC K25 HD SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	AGMXD06.0396	AGMXR0176821	BZ9XD06.0GFA-017	BZ9XR0176G2A	BZ9XD06.0GFA	EPA Cert
General Motors	2010	6.0	IMPCO Technologies, Inc.: CHEVROLET C35 SILVERADO 2WD, CHEVROLET K35 SILVERADO 4WD, GMC C35 SIERRA 2WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	AGMXD06.0396	AGMXR0223842	BZ9XD06.0GFA-018	BZ9XR0223G2A	BZ9XD06.0GFA	EPA Cert
General Motors	2010	6.0	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET C35 SILVERADO 2WD, CHEVROLET K25 SILVERADO 4WD, CHEVROLET K35 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC C35 SIERRA 2WD, GMC K25 HD SIERRA 4WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	AGMXD06.0396	AGMXR0223841	BZ9XD06.0GFA-019	BZ9XR0223GFA	BZ9XD06.0GFA	EPA Cert
General Motors	2010	6.0	NaturalDrive Partners: C25 Sierra 2WD, C25 Silverado 2WD, C35 Sierra 2WD, C35 Silverado 2WD, K25 HD Sierra 4WD, K25 Silverado 4WD, K35 Sierra 4WD, K35 Silverado 4WD	CNG	Gasoline	NaturalDrive Partners, LLC	AGMXD06.0396	AGMXR0223841; AGMXR0176821	ANTDD06.039A-002	ANTDR0000004	ANTDD06.039A	EPA Cert
General Motors	2010	6.0	NaturalDrive Partners: C25 Sierra 2WD, C25 Silverado 2WD, C35 Sierra 2WD, C35 Silverado 2WD, K25 HD Sierra 4WD, K25 Silverado 4WD, K35 Sierra 4WD, K35 Silverado 4WD	CNG	Gasoline	NaturalDrive Partners, LLC	AGMXD06.0396	AGMXR0223841; AGMXR0176821	CNTDD06.039A-003	CNTDR0000004	CNTDD06.039A	EPA Cert
General Motors	2010	6.0	Auto Gas America: Chevrolet C25 Silverado 2WD, Chevrolet K25 Silverado 4WD, GMC K25 HD Sierra 4WD, GMC Sierra 2WD	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	AGMXD06.0396	AGMXR0176821	BAGTD06.0396-004	BAGTR0176821	BAGTD06.0396	EPA Cert
General Motors	2010	6.0	Auto Gas America: Chevrolet C25 Silverado 2WD, Chevrolet K25 Silverado 4WD, Chevrolet K35 Silverado 4WD, GMC C35 Sierra 2WD, GMC K25 HD Sierra 4WD, GMC K35 Sierra 4WD, GMC Sierra 2WD	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	AGMXD06.0396	AGMXR0223841	BAGTD06.0396-005	BAGTR0223841	BAGTD06.0396	EPA Cert
General Motors	2010	6.0	Auto Gas America: Chevrolet C35 Silverado 2WD, Chevrolet K35 Silverado 4WD, GMC C35 Sierra 2WD, GMC K35 Sierra 4WD	CNG or gasoline	Gasoline	The CNG Store, LLC; dba Auto Gas America	AGMXD06.0396	AGMXR0223842	BAGTD06.0396-006	BAGTR0223842	BAGTD06.0396	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2010	3.5, 3.9	Chevrolet Impala, Buick Lucerne, Chevrolet Malibu, Pontiac G6	CNG	Gasoline	Auto Gas America	AGMXV03.9055; AGMXV03.9048	AGMXR0133810; AGMXR0123702		CAGTR0133810	CAGTV03.9048	Int Appr
General Motors	2010	3.5, 3.9	CNG - Dedicated GM: Buick Lucerne, Chevrolet Impala, Chevrolet Malibu, Pontiac G6	CNG	Gasoline/E85	EvoTek LLC	AGMXV03.9055; AGMXV03.9048	AGMXR0133810; AGMXR0123702	BETKV03.9N2A-005	BETKR0000E2E	BETKV03.9N2A	EPA Cert
General Motors	2010	3.5, 3.9	IMPCO Technologies, Inc.: Buick Lucerne, Chevrolet Impala	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AGMXV03.9055	AGMXR0133810	BZ9XV03.9GFA-025	BZ9XR0133GFA	BZ9XV03.9GFA	EPA Cert
General Motors	2010	3.5, 3.9	NaturalDrive Partners: G6, Impala, Lucerne, Malibu	CNG	Gasoline, gasoline/E85	NaturalDrive Partners, LLC	AGMXV03.9048; AGMXV03.9055	AGMXR0123702; AGMXR0133810	ANTDV03.905A-003	ANTDR0000005	ANTDV03.905A	EPA Cert
General Motors	2010	3.5, 3.9	NaturalDrive Partners: G6, Impala, Lucerne, Malibu	CNG	Gasoline/E85	NaturalDrive Partners, LLC	AGMXV03.9048; AGMXV03.9055	AGMXR0123702; AGMXR0133810	ANTDV03.905Z-004	ANTDR0000005	ANTDV03.905Z	EPA Cert
General Motors	2010	3.5, 3.9	NaturalDrive Partners: G6, Impala, Lucerne, Malibu	CNG	Gasoline/E85	NaturalDrive Partners, LLC	AGMXV03.9048; AGMXV03.9055	AGMXR0123702; AGMXR0133810	CNTDV03.905A-001	CNTDR0000000	CNTDV03.905A	EPA Cert
General Motors	2010	4.8, 5.3	CNG - Dedicated GM: GM 5.3L Truck	CNG	Gasoline/E85	EvoTek LLC	AGMXT05.3373; AGMXT05.3377; AGMXT05.3381; AGMXT05.3389	AGMXR0176820; AGMXR0223610; AGMXR0223840; AGMXR0170956; AGMXR0197972	AETKT05.3N1A-004	AETKR0000N1D	AETKT05.3N1A	EPA Cert
General Motors	2010	4.8, 5.3	IMPCO Technologies, Inc.: CHEV G1500 EXPRESS CONV 2WD CARG, CHEV H1500 EXPRESS CONV AWD CARG, Chevrolet G1500 EXPRESS 2WD CARG, Chevrolet G1500 EXPRESS 2WD PASS, Chevrolet H1500 EXPRESS AWD CARG, Chevrolet H1500 EXPRESS AWD PASS, GMC G1500 SAVANA 2WD CARGO, GMC G1500 SAVANA CONV 2WD CARGO, GMC H1500 SAVANA AWD CARGO, GMC H1500 SAVANA AWD CARGO CONV, GMC H1500 SAVANA AWD PASS	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AGMXT05.3373	AGMXR0223610	BZ9XT05.3GFA-028	BZ9XR0223G4A	BZ9XT05.3GFA	EPA Cert
General Motors	2010	4.8, 5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C1500 AVALANCHE 2WD, CHEVROLET C1500 SUBURBAN 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 AVALANCHE 4WD, CHEVROLET SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AGMXT05.3373	AGMXR0223840	BZ9XT05.3GFA-029	BZ9XR0223G6A	BZ9XT05.3GFA	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2010	4.8, 5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C15 SILVERADO XFE 2WD, CHEVROLET C1500 TAHOE 2WD, CHEVROLET C1500 TAHOE XFE 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA XFE 2WD, GMC C1500 YUKON 2WD, GMC C1500 YUKON XFE 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD	CNG or gasoline/E85	Gasoline/E85	IMPCO Technologies, Inc.	AGMXT05.3373	AGMXR0176820	BZ9XT05.3GFA-027	BZ9XR0176GFA	BZ9XT05.3GFA	EPA Cert
			NTD 2: G1500 Savana 2WD Cargo NaturalDrive Partners: C15 Sierra 2WD, C15 Sierra XFE 2WD, C15 Silverado 2WD, C15 Silverado XFE 2WD, C1500 Avalanche 2WD, C1500 Suburban 2WD, C1500 Tahoe 2WD, C1500 Yukon 2WD, C1500 Yukon XFE 2WD, C1500 Yukon XL 2WD, G1500 Express 2WD Pass, G1500 Savana 2WD Cargo Conv, G1500 Savana 2WD Pass, G1500 Van 2WD Cargo, G1500 Van Conv 2WD Cargo, H1500 Express AWD Pass, H1500 Savana AWD Cargo Conv, H1500 Savana Cargo AWD, H1500 Savana Pass Van AWD, H1500 Van AWD Cargo, H1500 Van Conv AWD Cargo, H3 4WD, H3T 4WD, K15 Sierra 4WD, K15 Silverado 4WD, K1500 Avalanche 4WD, K1500 Suburban 4WD, K1500 Tahoe 4WD, K1500 Yukon 4WD, K1500 Yukon XL 4WD	CNG	Gasoline/E85	NaturalDrive Partners, LLC	AGMXT05.3373; AGMXT05.3381; AGMXT05.3389	AGMXR0176820; AGMXR023610; AGMXR023840; AGMXR0197972	BNTDT05.3FEA-004	BNTDR0000009	BNTDT05.3FEA	EPA Cert
General Motors	2010	6.0, 4.8	Baytech Corporation: G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD PASS, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD PASS, G2500 SAVANA CONV 2WD CARGO, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD PASS, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD PASS, G3500 SAVANA CONV 2WD CARGO	CNG	Gasoline	Baytech Corporation	AGMXT06.0398	AGMXR023841	ABYTT06.0918-002	ABYTE0000000	ABYTT06.0918	EPA Cert, CARB

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2010	6.0, 4.8	Baytech Corporation: G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD PASS, G2500 EXPRESS CONV 2WD CARGO, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD PASS, G2500 SAVANA CONV 2WD CARGO, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD PASS, G3500 EXPRESS CONV 2WD CARGO, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD PASS, G3500 SAVANA CONV 2WD CARGO	CNG	Gasoline/E85	Baytech Corporation	AGMXT06.0398	AGMXR0223841	BBYTD06.0118-004	BBYTE0000000	BBYTD06.0118	EPA Cert
General Motors	2010	6.0, 4.8	Baytech Corporation: C35 SIERRA 2WD, C35 SILVERADO 2WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0223842	BBYTD06.0126-006	BBYTR0223826	BBYTD06.0126	EPA Cert
General Motors	2010	6.0, 4.8	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0223841	BBYTD06.0126-007	BBYTR0223846	BBYTD06.0126	EPA Cert
General Motors	2010	6.0, 4.8	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	AGMXD06.0396	AGMXR0176821	BBYTD06.0126-008	BBYTR0176826	BBYTD06.0126	EPA Cert
General Motors	2010	6.0, 4.8	NTD 2: G2500 Express 2WD Pass, G2500 Savana 2WD Pass Natural Drive Partners: G2500 Express 2WD Cargo, G2500 Express Conv 2WD Cargo, G2500 Savana 2WD Cargo, G2500 Savana Conv 2WD Cargo, G3500 Express 2WD Cargo, G3500 Express 2WD Pass, G3500 Express Conv 2WD Cargo, G3500 Savana 2WD Cargo, G3500 Savana 2WD Pass, G3500 Savana Conv 2WD Cargo	CNG	Gasoline/E85	Natural Drive Partners, LLC	AGMXT06.0398	AGMXR0223841	BNTDT06.0VAA-002	BNTDR0000007	BNTDT06.0VAA	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2010	6.2, 5.3, 4.8	Auto Gas America: Cadillac Escalade 2WD, Cadillac Escalade AWD, Chevrolet C15 K15 Silverado 2WD, Chevrolet C15 Silverado 2WD, Chevrolet C15 Silverado 2WD XFE, Chevrolet C1500 Tahoe 2WD, Chevrolet C1500 Tahoe 2WD XFE, Chevrolet K15 Silverado 4WD, Chevrolet K1500 Tahoe 4WD, GMC C15 Sierra 2WD, GMC C15 Sierra 2WD XFE, GMC C1500 Yukon 2WD, GMC C1500 Yukon 2WD XFE, GMC K15 Sierra 4WD, GMC K15 Sierra AWD, GMC K1500 Yukon 4WD, GMC K1500 Yukon Denali AWD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas Store	AGMXT05.3373; AGMXT06.2375	AGMXR0176820	BAGTT06.2375-001	BAGTR0176820	BAGTT06.2375	EPA Cert
			Auto Gas America: Chevrolet G1500 Express 2WD Pass, Chevrolet G1500 Van 2WD Cargo, Chevrolet H1500 Express Conv 2WD, Chevrolet H1500 Express AWD Pass, Chevrolet H1500 Van AWD Cargo, Chevrolet H1500 Van Conv AWD, GMC G1500 Savana 2WD Cargo, GMC G1500 Savana 2WD Cargo Conv, GMC G1500 Savana 2WD Pass, GMC H1500 Savana AWD Cargo Conv, GMC H1500 Savana AWD Pass, GMC H1500 Savana Cargo AWD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas Store	AGMXT05.3373	AGMXR0223610	BAGTT06.2375-002	BAGTR0223610	BAGTT06.2375	EPA Cert
			Auto Gas America: Cadillac Escalade ESV 2WD, Cadillac Escalade ESV AWD, Cadillac Escalade EXT AWD, Chevrolet C15 Silverado 2WD, Chevrolet C1500 Avalanche 2WD, Chevrolet C1500 Silverado 4WD, Chevrolet K15 Silverado 4WD, Chevrolet K1500 Yukon XL 2WD, GMC C15 Sierra 4WD, GMC C1500 Yukon XL 2WD, GMC K15 Sierra 4WD, GMC K1500 Yukon XL 4WD	CNG or gasoline/E85	Gasoline/E85	The CNG Store, LLC; dba Auto Gas Store	AGMXT05.3373; AGMXT06.2375	AGMXR0223840	BAGTT06.2375-003	BAGTR0223840	BAGTT06.2375	EPA Cert

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OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2009	5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C1500 AVALANCHE 2WD, CHEVROLET C1500 SUBURBAN 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 AVALANCHE 4WD, CHEVROLET K1500 SUBURBAN 4WD, GMC C15 SIERRA 2WD, GMC C1500 YUKON XL 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXT05.3373	9GMXR0223840	BZ9XT05.3GF9-007	BZ9XR0223G49	BZ9XT05.3GF9	EPA Cert
General Motors	2009	5.3	IMPCO Technologies, Inc.: CHEVROLET C15 SILVERADO 2WD, CHEVROLET C15 SILVERADO XFE 2WD, CHEVROLET C1500 TAHOE 2WD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 TAHOE 4WD, GMC C15 SIERRA 2WD, GMC C15 SIERRA XFE 2WD, GMC C1500 YUKON 2WD, GMC C1500 YUKON XFE 2WD, GMC K15 SIERRA 4WD, GMC K1500 YUKON 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXT05.3373	9GMXR0176820	BZ9XT05.3GF9-008	BZ9XR0176G29	BZ9XT05.3GF9	EPA Cert
General Motors	2009	6.0	CK20, Silverado 2500, Silverado 2500HD, GMC Sierra 2500, GMC Sierra 2500HD, CK30, Silverado 3500, Silverado 3500 Cab Chassis, Sierra 3500, Sierra 3500 Cab Chassis, Express Cutaway 35000, Savana Cutaway 3500, Workhorse Custom Chassis P30, Isuzu NPR, Chevrolet W3500, GMC W3500	CNG	Gasoline	Baytech Corporation			EO A-330-0207	9BYTF0000000		CARB
General Motors	2009	2.4, 2.2	SATURN AURA, PONTIAC G6, CHEVROLET MALIBU, CHEVROLET COBALT, PONTIAC G5, CHEVROLET COBALT XFE, PONTIAC G5 XFE, CHEVROLET CLASSIC	Gasoline/CNG	Gasoline	Auto Gas America	9GMXV02.4027	9GMXR0133810, 9GMXR0105817		CAGTR0133810	CAGTV02.4009	Int Appr
General Motors	2009	3.5, 3.9	HPG ALTERNATIVE FUEL: HPGg6, HPGimpala, HPGmalibu	CNG	Gasoline/E85	High Pressure Group LLC	9GMXV03.9048; 9GMXV03.9051; 9GMXV03.9052	9GMXR0123702; 9GMXR0133810	BHPGV03.9001-001		BHPGV03.9001	EPA Cert
General Motors	2009	3.5, 3.9	IMPCO Technologies, Inc.: Chevrolet Impala	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXV03.9052	9GMXR0133810	BZ9XV03.9GF9-012	BZ9XR0133GF9	BZ9XV03.9GF9	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2009	3.5, 3.9	NaturalDrive Partners: G6, Impala, Malibu	CNG	Gasoline/E85	NaturalDrive Partners, LLC	9GMXV03.9048; 9GMXV03.9051; 9GMXV03.9052	9GMXR0123702; 9GMXR0133810	ANTDV03.9059-001	ANTDR0000002	ANTDV03.9059	EPA Cert
General Motors	2009	4.8, 5.3	NTD 2: Canyon 2WD, Canyon Crew Cab 4WD, G1500 Savana 2WD Cargo NaturalDrive Partners: C15 Sierra 2WD, C15 Sierra XFE 2WD, C15 Silverado 2WD, C15 Silverado XFE 2WD, C1500 Avalanche 2WD, C1500 Suburban 2WD, C1500 Tahoe 2WD, C1500 Tahoe XFE 2WD, C1500 Yukon 2WD, C1500 Yukon XFE 2WD, C1500 Yukon XL 2WD, Canyon 4WD, Canyon Crew Cab 2WD, Colorado 2WD, Colorado 4WD, Colorado Crew Cab 2WD, Colorado Crew Cab 4WD, G1500 Express 2WD Pass, G1500 Savana 2WD Cargo Conv, G1500 Savana 2WD Pass, G1500 Van 2WD Cargo, G1500 Van Conv 2WD Cargo, H1500 Express AWD Pass, H1500 Savana AWD Cargo Conv, H1500 Savana Cargo AWD, H1500 Savana Pass Van AWD, H1500 Van AWD Cargo, H1500 Van Conv AWD Cargo, H3 4WD, H3T 4WD, K15 Sierra 4WD, K15 Silverado 4WD, K1500 Avalanche 4WD, K1500 Suburban 4WD, K1500 Tahoe 4WD, K1500 Yukon 4WD, K1500 Yukon XL 4WD	CNG	Gasoline, gasoline/E85	NaturalDrive Partners, LLC	9GMXT05.3381; 9GMXT05.3373; 9GMXT05.3376; 9GMXT05.3377; 9GMXT05.3380; 9GMXT05.3384	9GMXR0176820; 9GMXR0233840; 9GMXR0170956; 9GMXR0197972	BNTDT05.3389-001	BNTDR0000006	BNTDT05.3389	EPA Cert
General Motors	2009	6.0, 4.8	C2500 HD Sierra 2WD, C2500 HD Silverado 2WD, K2500 HD Sierra 4WD, G2500 Savana 2WD Cargo, G2500 Chevy Van 2WD Cargo, G3500 Savana 2WD Cargo, G3500 Chevy Van 2WD Cargo, G2500 Express 2WD Pass, G2500 Savana 2WD Cargo, G2500 Savana 2WD Pass, G2500 Chevy Van 2WD Cargo, G3500 Express 2WD Pass, G3500 Savana 2WD Cargo, G3500 Savana 2WD Pass, G3500 Chevy Van 2WD Cargo, C3500 Silverado 2WD, K3500 Sierra 4WD, K3500 Silverado 4WD	CNG	Gasoline	Baytech Corporation			EO A-330-0204-1	9BYTR0000000		CARB

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2009	6.0, 4.8	Baytech Corporation: C35 SIERRA 2WD, C35 SILVERADO 2WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	9GMXD06.0396	9GMXR0223842	BBYTD06.0226-001	BBYTR0176826	BBYTD06.0226	EPA Cert
General Motors	2009	6.0, 4.8	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, K25 HD SIERRA 4WD, K25 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	9GMXD06.0396	9GMXR0176821	BBYTD06.0226-002	BBYTR0176826	BBYTD06.0226	EPA Cert
General Motors	2009	6.0, 4.8	Baytech Corporation: C25 SIERRA 2WD, C25 SILVERADO 2WD, C35 SIERRA 2WD, C35 SILVERADO 2WD, G2500 EXPRESS 2WD CARGO, G2500 EXPRESS 2WD PASS, G2500 SAVANA 2WD CARGO, G2500 SAVANA 2WD PASS, G3500 EXPRESS 2WD CARGO, G3500 EXPRESS 2WD PASS, G3500 SAVANA 2WD CARGO, G3500 SAVANA 2WD PASS, K25 HD SIERRA 4WD, K25 SILVERADO 4WD, K35 SIERRA 4WD, K35 SILVERADO 4WD	CNG or gasoline	Gasoline	Baytech Corporation	9GMXD06.0396	9GMXR0223841	BBYTD06.0226-003	BBYTR0223846	BBYTD06.0226	EPA Cert
General Motors	2009	6.0, 4.8	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET K35 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC K25 HD SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXD06.0396	9GMXR0176821	BZ9XD06.0GF9-001	BZ9XR0176GF9	BZ9XD06.0GF9	EPA Cert
General Motors	2009	6.0, 4.8	IMPCO Technologies, Inc.: CHEVROLET C35 SILVERADO 2WD, CHEVROLET K35 SILVERADO 4WD, GMC C35 SIERRA 2WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXD06.0396	9GMXR0223842	BZ9XD06.0GF9-002	BZ9XR0223G29	BZ9XD06.0GF9	EPA Cert
General Motors	2009	6.0, 4.8	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET C35 SILVERADO 2WD, CHEVROLET G2500 EXPRESS 2WD PASS, CHEVROLET G2500 VAN 2WD CARGO, CHEVROLET G3500 EXPRESS 2WD PASS, CHEVROLET G3500 VAN 2WD CARGO, CHEVROLET K25 SILVERADO 4WD, CHEVROLET K35 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC C35 SIERRA 2WD, GMC G2500 SAVANA 2WD CARGO, GMC G2500 SAVANA 2WD PASS, GMC G3500 SAVANA 2WD CARGO, GMC G3500 SAVANA 2WD PASSENGER, GMC K25 HD SIERRA 4WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	9GMXD06.0396	9GMXR0223841	BZ9XD06.0GF9-003	BZ9XR0223GF9	BZ9XD06.0GF9	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2009	6.2, 5.3	GMC C15 SIERRA 2WD, CHEVROLET C15 SILVERADO 2WD, CHEVROLET C1500 TAHOE 2WD, GMC C1500 YUKON 2WD, CADILLAC ESCALADE 2WD, CADILLAC ESCALADE AWD, GMC K15 SIERRA 4WD, GMC K15 SIERRA AWD, CHEVROLET K15 SILVERADO 4WD, CHEVROLET K1500 TAHOE 4WD, GMC K1500 YUKON 4WD, GMC K1500 YUKON DENALI AWD, GMC C1500 YUKON XL 2WD, CADILLAC ESCALADE ESV 2WD, CADILLAC ESCALADE EXT AWD, GMC C1500 YUKON XL AWD, GMC C15 SIERRA XFE 2WD, CHEVROLET SILVERADO XFE 2WD, GMC C1500 YUKON XFE 2WD, CHEVROLET C1500 AVALANCHE 2WD, CHEVROLET K1500 SUBURBAN 2WD, CHEVROLET K1500 AVALANCHE 4WD, CHEVROLET K1500 SUBURBAN 4WD, GMC K1500 YUKON XL 4WD	CNG or gasoline/E85	Gasoline/E85	Auto Gas America	9GMXT06.2375, 9GMXT05.3373	9GMXR0176820, 9GMXR0223840		CAGTR017009	CAGTT06.2009	Int Appr
	2008	5.3	C15/C1500/K15/K1500: SIERRA, SILVERADO, TAHOE, YUKON, AVALANCHE, SUBURBAN, AVALANCHE	Gasoline/CNG	Gasoline	Zavoli, s.r.l.	8GMXT05.3379	8GMXR0176820, 8GMXR0223840		DZAVR0176820	DZAVT05.3701	Int Appr
	2008	6.0	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET K25 SILVERADO 4WD, GMC C25 SIERRA 2WD, GMC K25 HD SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	8GMXX06.0396	8GMXR0176821	BZ9XD06.0GF8-039	BZ9XR0176GF8	BZ9XD06.0GF8	EPA Cert

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2008	6.0	IMPCO Technologies, Inc.: CHEVROLET C25 SILVERADO 2WD, CHEVROLET C35 SILVERADO 2WD, CHEVROLET K25 SILVERADO 4WD, CHEVROLET K35 SILVERADO 4WD, Chevrolet G1500/2500 Express 2WD, Chevrolet G1500/2500 VAN 2WD, Chevrolet G3500 EXPRESS 2WD, Chevrolet G3500 VAN 2WD, GMC C25 SIERRA 2WD, GMC C35 SIERRA 2WD, GMC G1500/2500 SAVANA 2WD PASS, GMC G1500/2500 Savana 2WD CARGO, GMC G3500 SAVANA 2WD CARGO, GMC G3500 SAVANA 2WD PASSENGER, GMC K25 HD SIERRA 4WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	8GMXX06.0396	8GMXR0223841	BZ9XD06.0GF8-040	BZ9XR0223GF8	BZ9XD06.0GF8	EPA Cert
			IMPCO Technologies, Inc.: CHEVROLET C35 SILVERADO 2WD, CHEVROLET K35 SILVERADO 4WD, GMC C35 SIERRA 2WD, GMC K35 SIERRA 4WD	CNG or gasoline	Gasoline	IMPCO Technologies, Inc.	8GMXX06.0396	8GMXE0223842	BZ9XD06.0GF8-041	BZ9XR0223G28	BZ9XD06.0GF8	EPA Cert
			SATURN AURA, PONTIAC G6, CHEVROLET MALIBU, CHEVROLET COBALT, PONTIAC G5, CHEVROLET COBALT XFE, PONTIAC G5 XFE, CHEVROLET CLASSIC	Gasoline/CNG	Gasoline	Auto Gas America	8GMXV02.4027, 8GMXV02.4025, 8GMXV02.2028	8GMXR0133810, 8GMXR0105817		CAGTR0133810	CAGTV02.4008	Int Appr
			SATURN AURA, PONTIAC G6, CHEVROLET MALIBU, CHEVROLET COBALT, PONTIAC G5, CHEVROLET COBALT XFE, PONTIAC G5 XFE, CHEVROLET CLASSIC	Gasoline/CNG	Gasoline	Auto Gas America	8GMXV02.4027, 8GMXV02.4025, 8GMXV02.2028	8GMXR0133810, 8GMXR0105817		CAGTR0133810	CAGTV02.4008	Int Appr
General Motors	2007	5.3, 4.8, 5.3	C15/C1500/K15/K1500: SIERRA, SILVERADO, TAHOE, YUKON, AVALANCE, SUBURBAN, G15/G25/G1500/G2500/H1500/H2500: SAVANA, VAN, EXPRESS	Flex Fuel/CNG	Gasoline/E85	Zavoli, s.r.l.	7GMXT05.3375, 7GMXT05.3379, 7GMXT05.3384	7GMXR0176820, 7GMXR0223840		DZAVR0176820	DZAVT05.3700	Int Appr
General Motors	2007	6, 4.8	GMC C1500 SIERRA CLASSIC 2WD, CHEVROLET C1500 SILVERADO CLASSIC 2WD, GMC C25 SIERRA 2WD, CHEVROLET C25 SILVERADO 2WD,	Gasoline/CNG	Gasoline	CNG Solutions LLC	7GMXX06.0396	7GMXR0176821, 7GMXR0223841	DCGSR0176821	DCGSD06.0396		Int Appr
General Motors	2003	6.0	CADILLAC ESCALADE	Gasoline/CNG	Gasoline	Wise Gas Inc	3GMXT06.0187	3GMXE0111911		CWSGE0111MIU	CWSGT06.0MIU	OUL

OEM	Original Model Year	Eng Disp	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion MFR	OEM Test Group	OEM Evap Families	Conversion Certificate Number	Conversion Evap Family	Conversion Test Group	Compliance Status
General Motors	2000	3.8, 3.5, 3.4	GRAND PRIX, IMPALA, LUMINA/MONTE CARLO, REGAL, BONNEVILLE, CAMARO, FIREBIRD/TRANS AM, LESABRE, PARK AVE, CENTURY, ALERO, GRAND AM, MALIBU, CAMERO, INTRIGUE, AURORA	Gasoline/CNG	Gasoline	NGV Motori	YGMXV03.8951, YGMXV03.8901, YGMXV03.8045, YGMXV03.8044, YGMXV03.8043, YGMXV03.8042, YGMXV03.5064, YGMXV03.5063, YGMXV03.4041	YGMXR0133918, YGMXR0133910, YGMXR0124919, YGMXR0124912		BNGCR0133910	BNGCV03.8C01	Int Appr

EPA Cert - U.S. EPA certified
 CARB - California Air Resource Board
 Int Appr - Intermediate Approval by U.S. EPA
 OUL - Outside Useful Life Approval by U.S. EPA

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families (s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Caterpillar	2004 to 2006	15.2	C15	Diesel or Diesel/CNG	Diesel	American Power Group, Inc.	4CPXH0928EBK, 5CPXH0928EBK, 6CPXH0928EBK				BAPGH15.2CP4	OUL
Caterpillar	2004 to 2006	11.1, 12.5	C11, C13	Diesel or Diesel/CNG	Diesel	American Power Group, Inc.	4CPXH0763EBK, 5CPXH0680EBK, 5CPXH0763EBK, 6CPXH0680EBK, 6CPXH0763EBK				CAPGH12.5CP4	OUL
Caterpillar	1996 to 2003	10.3, 11.9	C-10, C-12	Diesel or Diesel/CNG Diesel/LNG	Diesel	American Power Group, Inc.	WCPXH0629ERK, WCPXH0729ERK, XCPXH0629ERK, XCPXH0729ERK, YCPXH0629ERK, YCPXH0729ERK, 1CPXH0629ERK, 1CPXH0729ERK, 2CPXH0629ERK, 2CPXH0729ERK, 3CPXH0629EBV, 3CPXH0629EBX, 3CPXH0729EBV, 3CPXH0729EBX, TCP629EZDARK, TCP629EZDARM, TCP729EZDARL, VCP629EZDARK, VCP629EZDARK, VCP729EZDARX				CAPGH11.9CP4	OUL
Caterpillar	1996 to 2003	14.6, 15.8	C-15, C-16	Diesel or Diesel/CNG Diesel/LNG	Diesel	American Power Group, Inc.	WCPXH0893ERK, WCPXH0967ERK, XCPXH0893ERK, XCPXH0967ERK, YCPXH0893ERK, YCPXH0967ERK, 1CPXH0893ERK, 1CPXH0967ERK, 2CPXH0893ERK, 2CPXH0967ERK, 3CPXH0893EBV, TCP893EZDARW, TCP893EZDARK, VCP893EZDARA, VCP893EZDARX, VCP967EZDARK				CAPGH15.8CP4	OUL
Caterpillar	1998 to 2002	11.9	C-12	Diesel/CNG	Diesel	Clean Air Power, Inc.	WCPXH0729ERK, XCPXH0729ERK, YCPXH0729ERK, 1CPXH0729ERK, 2CPXH0729ERK				BCLAH0729E6J	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Caterpillar	1998 to 2002	14.6	C-15	Diesel/CNG	Diesel	Clean Air Power, Inc.	WCPXH0893ERK, XCPXH0893ERK, YCPXH0893ERK, 1CPXH0893ERK, 2CPXH0893ERK				CCLAH0893EGJ	OUL
Cummins	2010 - 2012	15	ISX	Diesel/CNG/ LNG	Diesel	Peake Fuel Solutions, LLC	ACEXH0912XAP, ACEXH0912XAQ, ACEXH0912XAR, BCEXH0912XAP, BCEXH0912XAQ, BCEXH0912XAR, CCEXH0912XAP, CCEXH0912XAQ, CCEXH0912XAR		PKE-ONHWY-12-01		CPKEH0912ANQ	EPA cert
Cummins	2007 to 2009	10.8	ISM	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc.	7CEXH0661MAA, 7CEXH0661MAB, 7CEXH0661MAY, 7CEXH0661MAZ, 8CEXH0661MAA, 8CEXH0661MAY, 8CEXH0661MAZ, 9CEXH0661MAD, 9CEXH0661MAE, 9CEXH0661MAF, 9CEXH0661MAY, 9CEXH0661MAZ				DAPGH10.8CM7	OUL
Cummins	2007 to 2009	14.9	ISX	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group Inc	7CEXH0912XAK, 8CEXH0912XAK, 9CEXH0912XAK, 9CEXH0912XAP, 9CEXH0912XAQ, 7CEXH0912XAL, 7CEXH0912XAM, 8CEXH0912XAL, 8CEXH0912XAM, 9CEXH0912XAL, 9CEXH0912XAM, 9CEXH0912XAN				DAPGH14.9CM7	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Cummins	2004 to 2009	14.9, 10.8	ISX, ISM	Diesel or Diesel/CNG/LNG	Diesel	EcoDual Group LP	9CEXH0912XAK, 9CEXH0912XAL, 9CEXH0912XAM, 8CEXH0912XAK, 8CEXH0912XAL, 8CEXH0912XAM, 7CEXH0912XAK, 7CEXH0912XAL, 7CEXH0912XAM, 6CEXH0912XAK, 6CEXH0912XAL, 6CEXH0912XAM, 6CEXH0912XAH, 6CEXH0912XAJ, 5CEXH0912XAH, 5CEXH0912XAJ, 4CEXH0912XAH, 4CEXH0912XAJ, 9CEXH0661MAC, 9CEXH0661MAD, 9CEXH0661MAE, 9CEXH0661MAF, 9CEXH0661MAY, 9CEXH0661MAZ, 8CEXH0661MAA, 8CEXH0661MAB, 8CEXH0661MAC, 8CEXH0661MAY, 8CEXH0661MAZ, 7CEXH0661MAA, 7CEXH0661MAB, 7CEXH0661MAC, 7CEXH0661MAY, 7CEXH0661MAZ				BEDGE14.9ISX	OUL
	2002 to 2006	10.8	ISM	Diesel/LNG + Diesel	Diesel	American Power Group, Inc.	2CEXH0661MAT, 3CEXH0661MAT, 3CEXH0661MAU, 4CEXH0661MAT, 4CEXH0661MAU, 5CEXH0661MAX, 5CEXH0661MAT, 5CEXH0661MAU, 6CEXH0661MAT, 6CEXH0661MAU, 6CEXH0661MAX, 6CEXH0661MAY, 6CEXH0661MAZ				CAPGH10.8CM2	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Cummins	2002 to 2006	14.9	ISX	Diesel or Diesel/CNG	Diesel	American Power Group, Inc.	2CEXH0912XAG, 3CEXH0912XAH, 3CEXH0912XAJ, 4CEXH0912XAH, 4CEXH0912XAJ, 5CEXH0912XAH, 5CEXH0912XAJ, 6CEXH0912XAH, 6CEXH0912XAJ, 6CEXH0912XAM, 6CEXH0912XAK, 6CEXH0912XAL				CAPGH14.9CM2	OUL
Daimler Chrysler AG	2006	6.37	OM 906	CNG	Diesel	NGV Motori	6MBXH6.37DJA				BNGCH6.37DID	Int Appr
Daimler Chrysler AG	2005	6.37	OM 906	CNG	Diesel	NGV Motori	5MBXH6.37DJA				BNGCH6.37DJC	Int Appr
Daimler Chrysler AG	2004	6.37	OM 906	CNG	Diesel	NGV Motori	4MBXH6.37DJA				BNGCH6.37DIB	Int Appr
Daimler Chrysler AG	2003	6.37	OM 906	CNG	Diesel	NGV Motori	3MBXH6.37DJA				BNGCH6.37DJA	Int Appr
Daimler Chrysler	2000 to 2003	12, 12.8	OM457LA, OM460LA	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc	YMBXH12.0DJA, 1MBXH12.0DJA, 1MBXH12.8DJA, 2MBXH12.0DJA, 2MBXH12.8DJA, 3MBXH12.0DJA, 3MBXH12.8DJA				DAPGH12.8DC1	

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Detroit Diesel	2002 to 2009	12.7, 14.0, 12.8, 14.8	SERIES 60 12.7L, SERIES 60 14L, OM460LA, MBE 4000, DD15, DD13	Diesel/CNG + Diesel	Diesel	American Power Group, Inc.	4DDXH12.7EGY, 4DDXH14.0ELY, 5DDXH12.7EGY, 5DDXH14.0ELY, 6DDXH12.7EGY, 6DDXH14.0ELY, 7DDXH12.8DJA, 7DDXH14.0ELY, 8DDXH12.8DJA, 8DDXH12.8TER, 8DDXH14.0ELY, 8DDXH14.8EEY, 9DDXH12.8DJA, 9DDXH12.8DJD, 9DDXH12.8FED, 9DDXH12.8FEY, 9DDXH12.8TER, 9DDXH14.0ELD, 9DDXH14.0ELY, 9DDXH14.8EED, 9DDXH14.8EEY, 2DDXH12.7EGL, 2DDXH14.0ELL, 3DDXH12.7EGY, 3DDXH14.0ELY, 4MBXH12.8DJA, 5MBXH12.8DJA, 6MBXH12.8DJA				CAPGH14.8DD8	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Detroit Diesel	1987 to 2002	12.7, 12, 14	SERIES 60	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc	HGM12.7FZA0, JDD12.7FZA2, KDD12.7FZA1, LDD12.7FZA0, MDD12.7FZAX, NDD12.7FZA9, PDD12.7FZA7, PDD12.7FZDX, RDD12.EJDARA, RDD12.EJDASW, SDD12.EJDARA, SDD12.EJDASW, TDD12.EJDASW, TDD12.EJDARA, TDD12.EJDATW, VDD12.EJDARA, VDD12.EJDATA, WDDXH12.7EGD, XDDXH12.7EGL, XDDXH14.0ELL, YDDXH12.7EGL, YDDXH14.0ELL, 1DDXH12.7EGL, 1DDXH14.0ELL, 2DDXH12.7EGL, 2DDXH14.0ELL				DAPGH14.0DD1	OUL
							LDD11.1FZA3, MDD11.1FZA2, NDD11.1FZA1, PDD11.1FZD2, PDD11.1FZAX, RDD11.EJDARA, SDD11.EJDARA, TDD11.EJDARA, VDD11.EJDARA, WDDXH11.1EHD, XDDXH11.1EHL				DAPGH11.1DD1	OUL
Detroit Diesel	1990 to 1999	11.1, 11	SERIES 60	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc						OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status							
Detroit Diesel	2002 to 2009	12.7, 14, 12.8, 14.8	SERIES 60 , MBE 4000, OM460LA, NA, DD15, DD13	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc.	2DDXH12.7EGL, 2DDXH14.0ELL, 3DDXH12.7EGY, 3DDXH14.0ELY, 4DDXH12.7EGY, 4MBXH12.8DJA, 4DDXH14.0ELY, 5DDXH12.7EGY, 5MBXH12.8DJA, 5DDXH14.0ELY, 6DDXH12.7EGY, 6MBXH12.8DJA, 6DDXH14.0ELY, 7DDXH12.8DJA, 7DDXH14.0ELY, 8DDXH12.8DJA, 8DDXH14.0ELY, 8DDXH12.8TER, 8DDXH14.8EY, 9DDXH12.8DJA, 9DDXH12.8FED, 9DDXH12.8TER, 9DDXH14.0ELY, 9DDXH14.8EY, 9DDXH12.8JD, 9DDXH12.8FEY, 9DDXH14.0ELD, 9DDXH14.8EED				CAPGH14.8DD8	OUL							
Ford	2013	6.8	V-10, 285 hp	CNG	Gasoline	BAF Technologies			EO A-364-0037		DBAFE06.83NN	CARB							
Ford	2013	6.8	V-10, 242 hp	CNG	Gasoline	BAF Technologies			EO A-364-0038		DBAFE06.89NN	CARB							
Ford	2013	6.8	V-10/ 362 hp	CNG	Gasoline	Greenkraft Inc			EO A-398-0006		DGKTE06.8FM1	CARB							
Ford	2013	6.8	V-10, 251 hp	CNG	Gasoline	IMPACO Technologies			EO-A-328-0063		DZ9XE06.8DC2	CARB							
Ford	2013	6.8	V-10/362 hp	CNG	Gasoline	Landi Renzo USA Corporation			EO A-400-0006		DLDRE06.8C10	CARB							
Ford	2012	6.8	V-10/285 hp	CNG	Gasoline	BAF Technologies			EO A-364-0031		CBAFE06.83NN	CARB							
Ford	2012	6.8	V-10, 242 hp	CNG	Gasoline	BAF Technologies			EO A-364-0032		CBAFE06.89NN	CARB							
Ford	2012	6.8	E450, 251 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0052		CZ9XE06.8CA1	CARB							
Ford	2012	6.8	F450, 308 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0053		CZ9XE06.8CA2	CARB							
Ford	2012	6.8	V-10, F-450/550/650 Chassis Cab and F53/F59 Step Van Chassis	CNG	Gasoline	Landi Renzo USA Corporation	CFMXE6.8BW5		LDR-ONHWY-12-01		CLDRE06.8C10	EPA Cert, CARB							
Ford	2012	6.8	V-10/362 hp	CNG	Gasoline	Landi Renzo USA Corporation			EO A-400-0004		CLDRE06.8C10	CARB							
Ford	2011	6.8	V-10/231 hp	CNG or HCNG	Gasoline	BAF Technologies			EO A-364-0025		BBAFE06.89CH	CARB							
Ford	2011	6.8	V-10/285 hp	CNG	Gasoline	BAF Technologies			EO A-364-0027		BBAFE06.83NN	CARB							

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Ford	2011	6.8	V-10, 242 hp	CNG	Gasoline	BAF Technologies			EO A-364-0028		BBAFE06.89NN	CARB
Ford	2011	6.8	E450, 251 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0046		BZ9XE06.8C1A	CARB
Ford	2011	6.8	F450, 308 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0047		BZ9XE06.8C2A	CARB
Ford	2010	6.8	E-450, 242 hp, 285 hp	CNG	Gasoline	BAF Technologies	AFMXE06.8BW	AFMXF0265NAT	BAF-ONHWY-10-01	ABAF00000001	ABAFE06.89FN	EPA Cert, CARB
Ford	2009	6.8	E-450	CNG	Gasoline	BAF Technologies	9FMXE06.8BW	9FMXF0265NAT	BAF-ONHWY-09-01	9BAFF00000001	9BAFE06.89FN	EPA Cert, CARB
Ford	2009	6.8	V-10/231 hp	CNG or HCNG	Gasoline	BAF Technologies			EO A-364-0020		9BAFE06.89CH	CARB
General Motors	2013	6	V8/model 605851111, engine codes 20, 30, 40, 50, 60	CNG	Gasoline	Greenkraft Inc			EO-398-0005		DGKTE06.0GM2	CARB
General Motors	2013	6	GM 6.0/265 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0059		DZ9XE06.0DCA	CARB
General Motors	2013	6	GM 6.0L/323 hp	CNG	Gasoline	Landi Renzo USA Corporation			EO A-400-0005		DLDRE06.0C10	CARB
General Motors	2013	6	GM 6.0L/ 323	CNG	Gasoline	Landi Renzo USA Corporation			EO A-400-008		DLDRE06.0C11	CARB
General Motors	2012	6	GM 6.0L/323 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0233		CBYTE06.0C10	CARB
General Motors	2012	6	GM 6.0/323 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0234		CBYTE06.0C11	
General Motors	2012	6	Engine V8/ model 605840211, engine codes 20,30,40,50,60	CNG	Gasoline	Greenkraft Inc			EO A-398-0002		CGKTE06.0GM1	EPA, cert CARB
General Motors	2012	6	Engine V8/ model 605851111, engine codes 20,30,40,50,60	CNG	Gasoline	Greenkraft Inc			EO A-398-0003		CGKTE06.0GM2	EPA cert, CARB
General Motors	2012	6	Van 265 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0051		CZ9XE06.0DCA	CARB
General Motors	2012	4.8	L20/model 48581201110, engine codes 20, 40, 50	CNG	Gasoline	Greenkraft Inc			EO A-398-0004		CGKTE04.8GM1	CARB
General Motors	2011	4.8	Van 237 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0044		BZ9XE04.8C1A	CARB
General Motors	2011	6	Engine models 605840211, engine codes 20,30,40,50,60	CNG	Gasoline	Greenkraft Inc	BGMXE06.0584	N/A	GKT-ONHWY-11-01.1	N/A	BGKTE06.0GM1	EPA Cert, CARB
General Motors	2011	6	GM 6.0L/266 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0230		B8YTE06.0613	CARB
General Motors	2011	6	Van 265 hp	CNG	Gasoline	IMPACO Technologies			EO A-328-0045		BZ9XE06.0C1A	CARB
General Motors	2010	6	GM 6.0L/266 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0218		ABYTE06.0613	CARB
General Motors	2010	8.1	GM 8.1L/283 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0221		ABYTE08.1C13	CARB
General Motors	2010	8.1	GM 8.1L/256 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0222		ABYTE08.1C12	CARB
General Motors	2009	6	GM 6.0L/266 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0205		9BYTE06.0613	CARB
General Motors	2009	6	GM 6.0L/266 hp CNG, 287 hp gasoline	CNG or Gasoline	Gasoline	Baytech Corporation			EO A-330-0216		9BYTE06.0623	CARB

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
General Motors	2009	8.1	GM 8.1L/283 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0208-1		98YTE08.1C13	CARB
General Motors	2009	8.1	GM 8.1L/256 hp	CNG	Gasoline	Baytech Corporation			EO A-330-0211		98YTE08.1C12	CARB
General Motors	2009	8.1	GM 8.1L/283 hp CNG, 317 hp gasoline	CNG or Gasoline	Gasoline	Baytech Corporation			EO A-330-0212		98YTE08.1C23	CARB
General Motors	2009	8.1	Workhorse Custom Chassis W30, W62 (283 hp CNG, 317 hp gasoline)	CNG or Gasoline	Gasoline	Baytech Corporation			EO A-330-0213		98YTF0407000	CARB
General Motors	2009	8.1	C4: Chevrolet Kodiak C4500, GMC Topkick C4500, 283 hp CNG, 317 gasoline	CNG or Gasoline	Gasoline	Baytech Corporation			EO A-330-0213		98YTF0300998	CARB
International Truck and Engine Corp.	2006	466	6NVHX0466AEA	CNG	Diesel	NGV Motori	6NVHX0466AEA				CNGCH0466AEA	Inter Appr
International Truck and Engine Corp.	2005	466	5NVHX0466AEA	CNG	Diesel	NGV Motori	5NVHX0466AEA				CNGCH0466AEB	Inter Appr
International Truck and Engine Corp.	2004	466	4NVXH0466AEA	CNG	Diesel	NGV Motori	4NVXH0466AEA				CNGCH0466AEC	Inter Appr
Mack	2004 to 2006	11.9	AC-460P, AC-460E, AC-427, AC-400, AC-355/380, AC-350, AC-330/350, AC-380/410, AC-310/330	Diesel/CNG	Diesel	FYDA Energy Solutions and The Hardstaff Group	4MKXH11.9H70, 5MKXH11.9H70, 6MKXH11.9H70, 4MKXH11.9H64				DFYDT11.9MAC	
Mack	2004 to 2006	11.9	AC-460P, AC-460E, AC-427, AC-400, AC-355/380, AC-350, AC-330/350, AC-380/410, AC-310/330	Diesel/CNG	Diesel	FYDA Energy Solutions and The Hardstaff Group	4MKXH11.9H70, 5MKXH11.9H70, 6MKXH11.9H70, 4MKXH11.9H64				DFYDT11.9MAC	
Navistar	2000 to 2003	7.6	C175, C195, CH195, CH215, CL215, C215, C230, CH230, C250, CH250	CNG	Diesel	Omnitek Engineering Corp.	1NVXH0466ANA, 2NVXH0466ANA, 3NVXH0466ANA, YNVXH0466ANA, 1NVXH0466ANB, 2NVXH0466ANB, 3NVXH0466ANB, YNVXH0466ANB				DOMNH07.6466	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status
Navistar	1996 to 2003	8.7	BT250, A250C, A250F, AL275C, AL275F, C275, CG275, AB275F, AF275C, AF275F, BT275, CH275, A275, A275C, A275F, BH275, CT280, C280, CV280, C300, AL300C, AL300F, CL300, AF300C, AF300F, A300, A300C, A300F, CH300, CV300, AF320C, AF320F, A330C, A330F, C330, CV320, A330, BH330, CH330, CV340	CNG	Diesel	Omnitek Engineering Corp.	XNVXH0530ACT, WNVXH0530CCB, WNVXH0530FNA, 1NVXH0530ANA, 1NVXH0530ATA, 2NVXH0530ANA, 2NVXH0530ATA, 3NVXH0530ANA, 3NVXH0530ATA, 3NVXH0530ATA, TNV530D8DARA, TNV530F8DAAA, VNV530D8DARA, VNV530D8DARA, XNVXH0530ANA, 1NVXH0530ACT, 2NVXH0530ACT, 3NVXH0530ACT, YNVXH0530ANA, YNVXH0530ACT, 2NVXH0530ANC, 3NVXH0530ANC, 2NVXH0530ANB, WNVXH0530CCD, WNVXH0530FNC, 1NVXH0530ANB, 3NVXH0530ANB, TNV530E8DASA, VNV530E6DASA, VNV530E8DASA, XNVXH0530ANB, YNVXH0530ANB				DOMNH08.7530	OUL
Navistar	1996 to 1999	7.6	A175, A175C, A175F, A190, A190C, A190F, A195, A195C, A195F, A210, A 210F, A210C, A210F, BH210, A230, A230C, A230F, A250, AB250F, A250C, A250F, B250	CNG	Diesel	Omnitek Engineering Corp.	VNV466D8DARW, WNVXH0466CCB, WNVXH0466FNA, XNVXH0466ANA, TNV466D8DARB, VNV466D8DASA, WNVXH0466CCD, WNVXH0466FNC, TNV466D8DATB, VNV466F8DAAA, XNVXH0466ANB				DOMNH07.6465	OUL

OEM	Original Model Year	Eng Disp (L)	Conversion Models Covered	Converted to Operate On	Original Fuel	Conversion Manufacturer	OEM Engine Families(s)	OEM Evap Families (if applicable)	Conversion Exhaust Certificate Number	Conversion Evap Family	Conversion Engine Family	Compliance Status																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																	
Volvo	2002 to 2009	11.9, 12.1, 12.8	E7, D12, MP8, D13	Diesel or Diesel/CNG or Diesel/LNG	Diesel	American Power Group, Inc	2MKXH11.9H04, 2MKXH11.9V65, 2MKXH11.9V66, 2MKXH11.9V67, 3MKXH11.9H64, 3MKXH11.9H70, 3MKXH11.9V65, 3MKXH11.9V67, 3MKXH11.9V68, 4VTXH12.150S, 4MKXH11.9H64, 4MKXH11.9H70, 4MKXH11.9H73, 4MKXH11.9V65, 4MKXH11.9V67, 4MKXH11.9V71, 5VTXH12.150S, 5MKXH11.9V71, 5MKXH11.9V65, 5MKXH11.9V74, 5MKXH11.9V67, 5MKXH11.9H70, 5MKXH11.9H73, 6VTXH12.150S, 6MKXH11.9V71, 6MKXH11.9V74, 6MKXH11.9V67, 6MKXH11.9V65, 6MKXH11.9H70, 6MKXH11.9H73, 6MKXH11.9V75, 6VPTH12.8H01, 6VPTH12.8H02, 6VPTH10.8H01, 6VPTH10.8H02, 6VPTH10.8H03, 7VPTH10.8H04, 8VPTH10.8H03, 8VPTH10.8H04, 9VPTH10.8H03, 9VPTH10.8H04, 6VPTH16.1H01, 7VPTH16.1H01, 8VPTH16.1H01, 9VPTH16.1H01					DAPGH12.8VP7	OUL																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																

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Clean Air Power, Inc.	13615 Stowe Drive, Poway, CA 92064	Kevin Campbell	909-393-7933	kcampbell@cleanairpower.com	cleanairpower.com
CNG Store (dba Auto Gas Store, or Auto Gas America)	350 N 650 W, Kaysville, UT 84037	Bryan Wilcox	866-931-8940	support@autogasamerica.com	autogasamerica.com
EcoDual, Inc.	9 Pin Drop Lane, Beaufort, SC 29902	John Reale	843-379-3825	ir@ecodual.com	ecodual.com
Go Natural CNG	2023 South 625 West, Woods Cross, UT 84087	Lucas Kjar	801-281-4766	lkjar@gonaturalcng.com	gonaturalcng.com
Greenkraft Inc	2530 S. Birch Street, Santa Ana, CA 92707	Sosi Bardakjian	714-545-7777	sosi@greenkraftinc.com	greenkraftinc.com
High Pressure Group	1468 James Road, Gardnerville, NV 89460	Trent Colbert	775-455-4059	info@highpressuregroup.com	highpressuregroup.com
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Landi Renzo USA/Baytech	23535 Telo Avenue, Torrance, CA 90505	Barry Carr	315- 278-2061	bcarr@LandiUSA.com	landiusa.com
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Wise Gas, Inc.	PO Box 266774, Weston, FL 33326	Sara Neal	954-636-4291	Sara@wisegasinc.com	wisegasinc.com

Please visit company websites for information on specific availability and ordering systems before contacting directly.

SEC INTERROGATORY #132

INTERROGATORY

Issue E46: Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Please provide a forecast (9+3 or 10+2) of actual rate base for 2013, and compare that forecast to Ex. N1, Tab 1, Schedule 1, Appendix A, Part 1, page 2 of EB-2011-0354. Where there are any significant differences between the Exhibit and the current forecast for 2013, please provide a detailed justification for those differences.

RESPONSE

The Company is not able to provide a forecast of 2013 rate base within the timelines for interrogatory responses and if it could does not believe it would be particularly informative to its Customized IR application. The development of the 2014 through 2018 forecast rate base amounts in the application used the 2013 Board Approved year end Property, Plant and Equipment ("PPE") balances as the starting point for their derivation.

As seen in the response to CCC Interrogatory #26 at Exhibit I.B18.EGDI.CCC.26. EGD's forecast capital expenditures are higher than the 2013 Board Approved levels. If EGD were to have used such an updated forecast of 2013 capital expenditures to develop a PPE starting point for the 2014 rate base then each of the 2014 through 2018 forecast rate base amounts would be higher.

SEC INTERROGATORY #133

INTERROGATORY

Issue E46: Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Please provide a forecast (9+3 or 10+2) of actual O&M costs excluding customer care, DSM and pension costs, but including RCAM and all other costs, for 2013. Please prepare the forecast on the same basis as the totals for All Other O&M plus RCAM in Ex. N1, Tab 1, Schedule 1, p. 18 and 19. Please compare these 2013 forecasts to the agreed 2013 All Other O&M of \$256.8 million. Where there are any significant differences between the Exhibit and the current forecast for 2013, please provide a detailed explanation for those differences.

RESPONSE

The significant differences between the Exhibit and the forecast are primarily due to higher safety and compliance related activities. Please also refer to the response to School Energy Coalition Interrogatory # 68 at Exhibit I.B17.EGDI.SEC.68.

Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2013 Budget to 2013 Forecast

Line No.	Categories (\$ Millions)	Col. 1	Col. 2	Col. 3
		Board Approved <u>2013</u>	Forecast <u>2013</u>	<u>Difference</u>
1.	OPEB	\$5.5	\$5.5	\$0.0
2.	Regulatory Cost Allocation Methodology("RCAM")	32.1	32.1	0.0
3.	Other O&M	219.2	235.3	16.1
4.	Total Net Utility O&M Expense	<u>\$256.8</u>	<u>\$272.9</u>	<u>\$16.1</u>

Witnesses: S. Kancharla
R. Lei

SEC INTERROGATORY #134

INTERROGATORY

Issue E46: Has Enbridge responded appropriately to all relevant Board directions from previous proceedings, including commitments from prior settlement agreements?

Please identify all components of the Application that the Applicant believes respond to the Applicant's commitment in Exhibit N1, Tab 1, Schedule 1 at Issue O3, dealing with productivity and efficiency record-keeping.

RESPONSE

In responding to the commitment in Exhibit N1, Tab 1, Schedule 1 at Issue O3, the Company has proposed a Performance Measurement Framework within this Customer IR Application as explained in evidence found at Exhibit A2, Tab 11, Schedule 2. The proposed framework is comprised of two reporting mechanisms: (1) Productivity Initiatives Report, and (2) Performance Metrics Benchmarking Report. The framework will provide visibility into the Company's efforts in implementing sustainable Productivity initiatives and an effective mechanism to communicate performance and outcomes over the IR term.

The proposed Productivity Initiatives Report will provide the Board and stakeholders a productivity reporting mechanism that demonstrates the Company's activities in pursuing productivity through customer, operational and financial performance initiatives to maintain safety, system reliability, and customer focused objectives. The Company proposes to file the Productivity Initiatives Report to the Board annually as part of the proposed annual Earnings Sharing Mechanism ("ESM") applications during the 2014 to 2018 IR term.

Please refer to Exhibit A2, Tab 11, Schedule 2, for further details about the Productivity Initiatives Report's components, objectives, and guiding principles.

Witnesses: I. Chan
S. Kancharla
I. MacPherson

SEC INTERROGATORY #135

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

Please file the 2012 Asset Plan, which is Exhibit B2, Tab 2, Schedule 1 in EB-2011-0354.

RESPONSE

The 2012 Asset Plan is attached as part of the response to this interrogatory.



EGD Asset Plan

2012-2021



May 9, 2012

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1. Executive Summary

Enbridge Gas Distribution (EGD) is one of North America's oldest investor-owned, regulated natural gas distribution utilities and shares many of the challenges facing some of its North American counterparts – an increased focus on safety and reliability, aging assets, an aging workforce, and the need to cost-effectively meet the demands of customer growth in its franchise area.

In response to these challenges, EGD has been adopting an Asset Management System approach to managing its distribution assets. Through the adoption of this approach, EGD is striving to enhance the value delivered to its customers through enhanced safety, reduced service disruptions, and improved cost effectiveness.

An Asset Plan is an important component of any Asset Management System. It defines and communicates what needs to be done with the organization's core assets over a specified period of time, the rationale behind these activities, and the resources needed for execution.

EGD's Asset Plan is a rolling 10-year plan that establishes the Company's distribution asset spending priorities over the term of the plan in a manner which attempts to address system needs while being mindful of ratepayer impacts.

This first iteration of the Asset Plan applies to the 2012-2021 time period. Going forward, the plan will be reviewed and updated on an annual basis. The scope of the plan includes EGD's core gas distribution system assets – Pipelines (Mains and Services), Valves, Fittings, and Measurement & Regulation equipment such as stations.

The Asset Plan includes a set of guiding principles which define EGD's Asset Management Objectives, Policies and Strategies.

Consistent with these guiding principles, the Asset Plan establishes the requirements and estimates the related capital expenditures to support four primary kinds of asset-related investments - Customer Additions, Reinforcements, System Integrity & Reliability, and Relocations.

Customer Additions:

EGD has experienced significant customer growth in its franchise area. This growth is forecast to continue in the future, as outlined in the chart below, driving the need to make continued investments in new distribution plant to service these new customers.

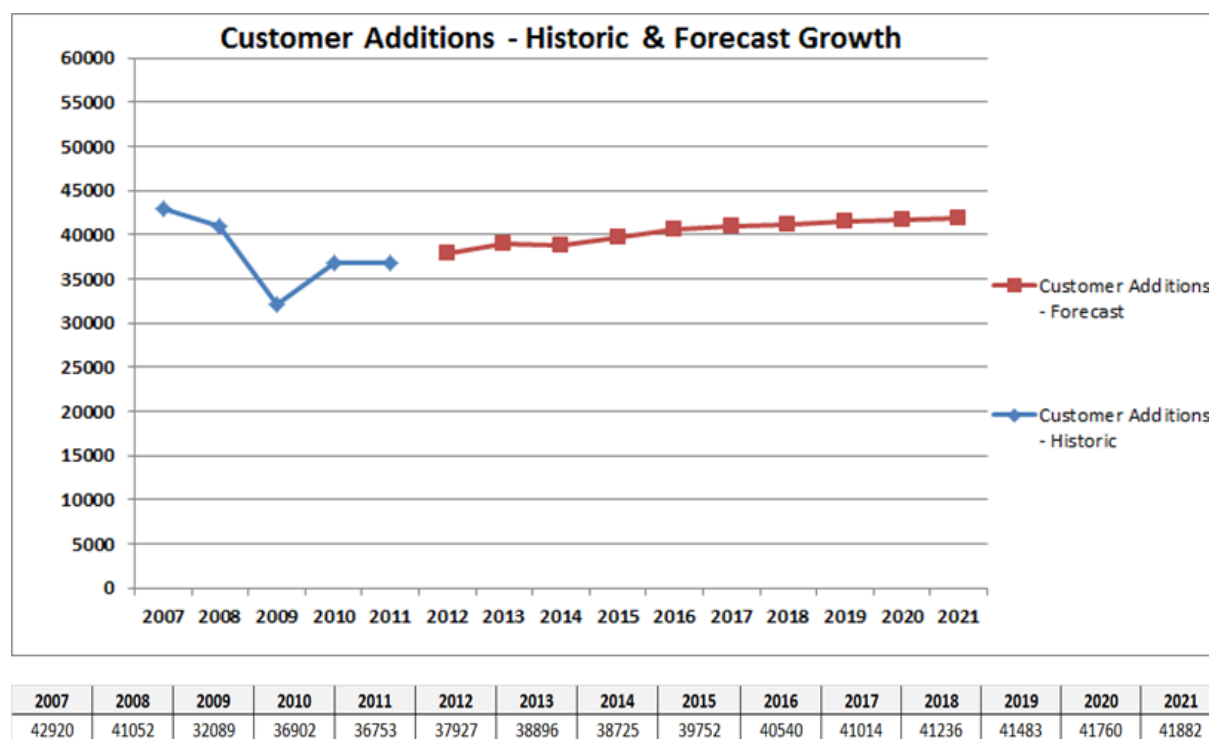


Chart 1 - Executive Summary: Customer Additions – Historic & Forecast Growth

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. Investments required to reinforce the distribution system are primarily driven by Customer Growth and System Integrity & Reliability considerations. As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up EGD's franchise area (Areas 10, 20, 30, 40, 50, 60 and 80). This analysis has determined that a significant increase in reinforcement investment is required over the 10 year horizon of this Asset Plan.

In addition to several routine reinforcements, two major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system serving the GTA

and Ottawa areas are required to further support customer growth and address significant system reliability and security of supply issues.

System Integrity & Reliability:

A critical responsibility in managing a gas distribution system is understanding potential threats to the safety and reliability of the system. This can be accomplished through condition monitoring, as well as reference to historical knowledge and industry developments and trends. By understanding these threats and the risks that they can manifest, mitigation programs have been, and continue to be developed and implemented to effectively manage these risks.

In addition, recent events in the natural gas industry, such as the tragic San Bruno explosion in September 2010, the Philadelphia explosion in January 2011, and the Allentown explosion in February 2011, have resulted in increased focus on public safety.

As part of applying an Asset Management System approach, EGD has made a concerted effort to identify, assess and prioritize risks to its distribution system and to continue to develop and implement programs to monitor, repair or replace components of the system as required, as part of this Asset Plan. In cases where risks require further analysis before the extent of mitigation can be determined, targeted risk studies have been identified and also included in this plan. These studies may result in additional programs or projects to address risks in future iterations of the plan.

The following are some of the key initiatives that represent a significant portion of the capital investments for System Integrity and Reliability requirements outlined in the Asset Plan:

- The need to continue to address classes of assets that are near the end of their useful life. Examples include Copper Services, Steel Tubing Services, AMP Fittings, and Mainline Compression Couplings
- The need to continue to conduct studies to improve our understanding of the condition of specific classes of assets where risks have been identified. These studies will help establish the requirements and scope of any related mitigation programs
- A number of initiatives to continue to enhance Records Integrity, including completeness, accuracy, verifiability, timeliness, and accessibility
- In-line inspect targetted XHP pipelines operating over 20% Specified Minimum Yield Strength (SMYS)

- Install additional mainline valves at key locations to enhance EGD's capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions

Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects.

In forecasting future years' relocations, EGD begins with the historical level of relocation activity and then adds projects or programs identified as incremental to that historical level. Within the 10 year horizon of this Asset Plan, a number of incremental activities, which are already underway or announced, are driving forecast relocation costs above historical levels. These activities include items such as Infrastructure Stimulus Fund activities, major transit projects (TTC Subway expansion, GTAA Rail Link, Rapid Transit – Eglinton LRT, York Region Rapid Transit, and Ottawa LRT), major road expansions (407 Extension) and preparations for the 2016 Pan Am Games.

Forecast Capital Cost of the Asset Plan

The following two charts summarize the total capital spend profile required to effectively meet the Customer Additions, Reinforcement, System Integrity & Reliability, and Relocation requirements included in this Asset Plan, as compared to the historic spend. The forecast costs are based on 2012 dollars (i.e. inflation and other time-based adjustments have not been applied) and include only the direct capital costs of the projects and initiatives.

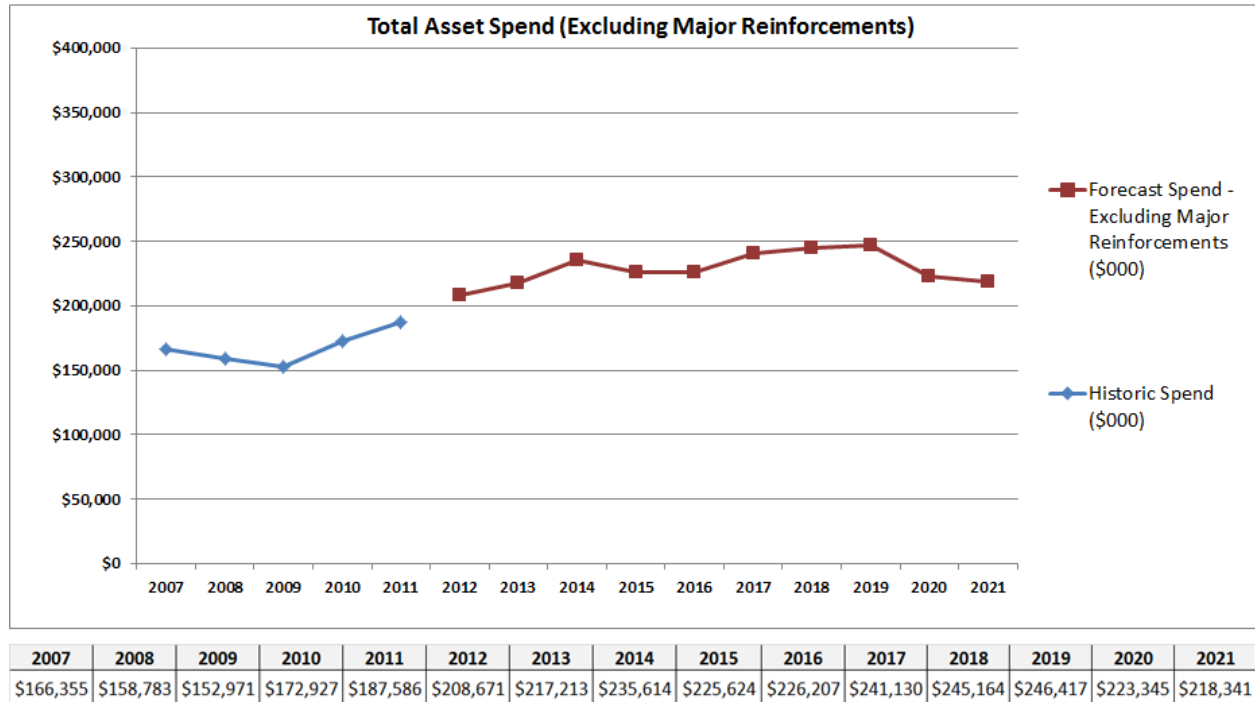


Chart 2 - Executive Summary: Historic & Forecast Capital Spend (Excluding Major Reinforcements)

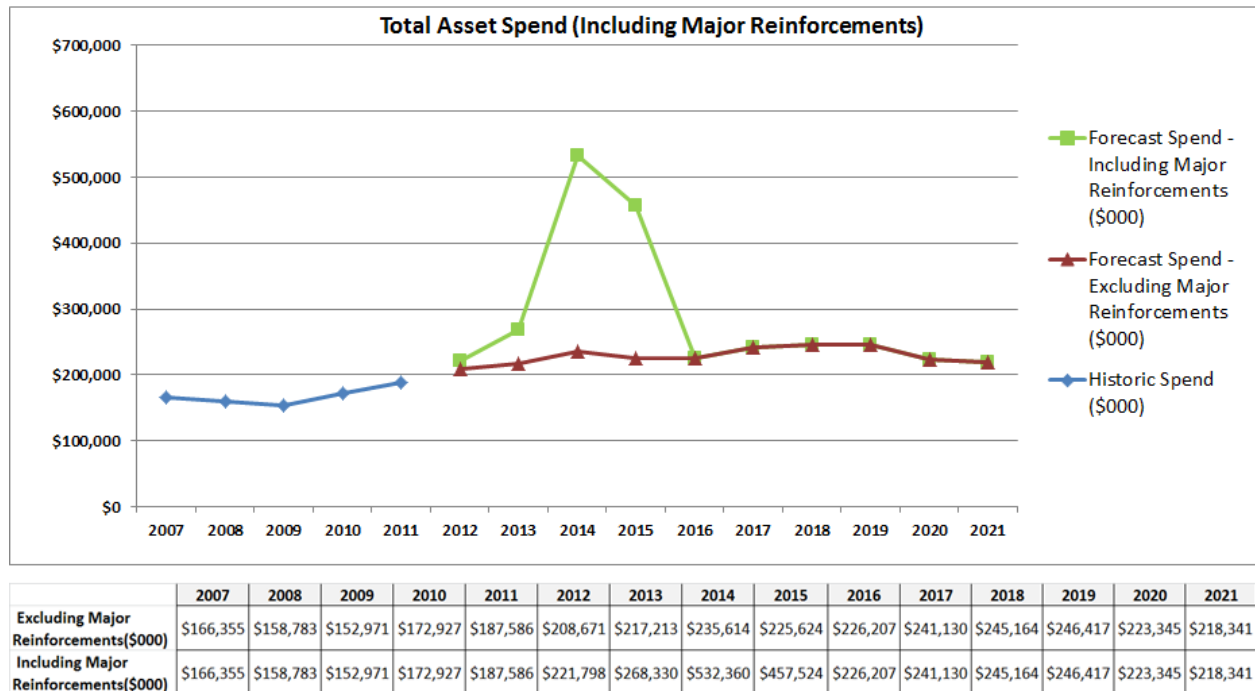


Chart 3 - Executive Summary: Historic & Forecast Capital Spend (Including Major Reinforcements)

2. Introduction

2.1 Background & Context

EGD is one of North America's oldest investor-owned, regulated natural gas distribution utilities and shares many of the challenges facing some of its North American counterparts – an increased focus on safety and reliability, aging assets, an aging workforce, and the need to cost-effectively meet the demands of customer growth in its franchise area. While meeting these challenges, EGD remains committed to the safe, reliable operation of its gas distribution network.

In response to these challenges, EGD has been working over the past several years to build on and enhance its past practices using an Asset Management System approach. Asset Management, as an approach, has been evolving over the past several years in a broad range of asset intensive industries, including utilities. The primary objective of an Asset Management System is to provide management with a systematic approach to making optimal asset related decisions based on trying to achieve an appropriate balance of risks, operational performance and costs. Achieving this balance enhances the value that EGD delivers to its customers through enhanced safety, reduced service disruptions, and improved cost effectiveness.

In working to adopt an Asset Management System approach, EGD has been using an asset management conceptual model developed by the Institute of Asset Management. This model was detailed in the asset management standard called PAS 55, a "Publicly Available Specification" published by the British Standards Institute. EGD took this model and adapted it to its gas distribution business.

Another important reference used by the Company was the Guiding Document on Asset Management released by the Canadian Gas Association in 2009. The CGA defines Asset Management as:

A strategic management system used to optimally manage assets over their life cycle by balancing performance, risk, and expenditures to achieve corporate strategic objectives.

From these reference sources, EGD created a framework that outlines all the major components of a comprehensive Asset Management System. EGD has used this framework to assess its current Asset Management activities to identify gaps and areas for improvement. Addressing these opportunities has become a continuous improvement process. Some areas

where work has already started include system health and performance monitoring, risk assessment and management, asset data, capital management, life cycle cost and value optimization and asset management leadership and accountability. These areas will continue to improve, through the Asset Management process going forward.

A key component of the Asset Management System is Asset Management Strategy and Planning. In addressing this Asset Management System requirement, EGD turned its attention to the development of a 10 year Asset Plan which will guide asset-related investments.

This document provides the first iteration of the plan, which will be reviewed, updated and improved every year going forward, thereby creating a 10-year rolling plan.

2.2 Purpose & Objectives of the Asset Plan

The purpose of an asset plan is to define and communicate what needs to be done with the organization's core assets over a specified period of time, the rationale behind these activities, and the resources needed for execution, consistent with the Company's key priorities. The needs of the assets should be considered over their entire life cycle including creation or acquisition, operation, maintenance and decommissioning.

EGD's Asset Plan establishes the Company's distribution asset spending priorities over a 10-year period (2012-2021) in a manner which attempts to address system needs while being mindful of ratepayer impacts.

More specifically, the objectives of this plan are:

- Align asset-related activities with the Company's key priorities (including safety, reliability, risk management, customer satisfaction, productivity and innovation)
- Provide inputs to the Company's long term planning and budgeting processes
- Provide a basis for substantiating financial requirements
- Meet regulatory requirements
- Serve as a mechanism to communicate EGD's asset management priorities and planned investments with internal and external parties

The target audience of the plan includes EGD's Senior Management, Operational Managers, partners, and external parties such as the OEB and other applicable stakeholders.

2.3 Scope of the Asset Plan

The following are the key elements that define the scope of this Asset Plan:

- The planning horizon for the Asset Plan is 10 years, 2012 to 2021.
- Organizationally, the Plan is limited to assets owned and operated by EGD across all regions within its franchise area.
- The Plan applies to core gas distribution assets only. These are physical plant assets that primarily make up the gas distribution system, including Pipelines (Mains & Services), Fittings, Valves, Stations, Meters and other Measurement & Regulation assets.
- The Plan does not include other assets such as Facilities, IT and Fleet.
- For this first iteration of the Asset Plan, Storage assets at EGD's Tecumseh Storage facility have not been included. In the future, EGD expects to include storage assets within the scope of the Asset Plan.
- This first iteration of the Asset Plan is focused on the capital investment requirements to optimally manage EGD's distribution assets. In future iterations, O&M requirements which are currently addressed in our O&M budgets will be addressed in more detail in the Asset Plan.

Based on the scope assumptions above, the Asset Plan will help substantiate a significant portion, but not all of EGD's capital requirements.

The Asset Plan is intended to supplement, but not replace, the evidence to be filed by the Company in support of its budget requirements in rate application filings.

2.4 High Level Overview of EGD's Asset Planning Process

Based on industry best-practices and internal expertise, EGD has developed, adapted and employed its own asset planning process. At the high level, this four-step process can be summarized as follows.

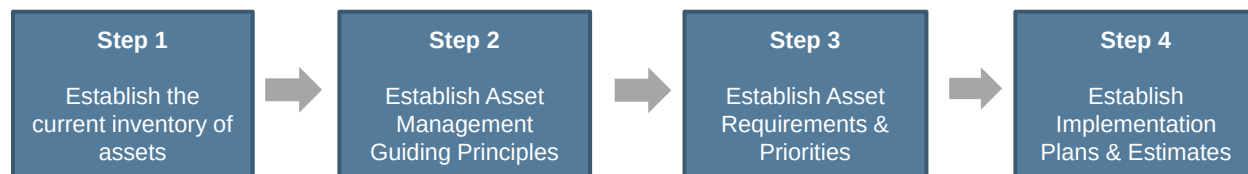


Figure 1 - Asset Planning Process

Step 1: Establish the Current Inventory of Assets:

The Distribution System is comprised of thousands of discrete components. To analyze and determine the needs of the assets, it is necessary to develop an appropriate classification for those assets, and inventory those assets by class rather than try to deal with discrete components.

- Based on the scope of the Asset Plan, a suitable “Asset taxonomy” has been established. The taxonomy identifies the key assets, and classifies them into a hierarchy
- Using the taxonomy as a reference, an inventory of assets was established. This represents a count of the key assets within the asset hierarchy
- Information on the asset inventory is supported by an explanation of relevant details on each class of asset, such as its age distribution

Step 2: Establish Asset Management Guiding Principles:

- Guiding Principles provide the basis and rationale for Asset Management decisions
- These principles include Asset Management Objectives, Policies, and Strategies

Step 3: Establish Asset Requirements & Priorities:

When considering asset requirements and priorities, it is necessary to consider the various types of asset investments that are required to build, operate and maintain the distribution system.

- Considering the various types of asset investments, there are primarily four categories of requirements that determine the overall plan for all the assets within the scope of the Asset Plan:
 - a. Customer Additions
 - b. Relocations
 - c. Reinforcements
 - d. System Integrity & Reliability
- The approach to establishing these requirements and prioritizing them varies by category
- In general, the requirements and priorities are determined based on a variety of sources of information, including asset condition data from operational systems, results of risk assessments, studies, forecasts, tacit knowledge, and historical information.

Step 4: Establish Implementation Plans & Estimates:

- The implementation plan establishes the scope and timing of asset-related projects, programs and investments that are needed to meet the asset requirements and priorities
- Capital investments needed to support the execution of the implementation plans are estimated by using a variety of approaches as appropriate, including historical expenditures and unit costs where available
- To the extent possible, an attempt has been made to manage potential rate impacts and resource availability by smoothing the expenditure profile and spreading out the costs over a longer term

3. Overview of EGD's Distribution Assets

This section provides an overview of how EGD classifies distribution assets, an inventory count, geographic distribution, and age-related profiles. This information will particularly help set the context for the discussion on System Integrity and Reliability requirements, strategies and plans that are discussed in subsequent sections of this document.

3.1 Asset Taxonomy and Inventory

EGD's distribution assets have been classified into four classes – Pipe, Fittings, Measurement & Regulation Equipment including Stations, and Valves. A further level of categorization has been done based on the sub-type of assets by material type / function. Figure 2 below is a depiction of the asset hierarchy.

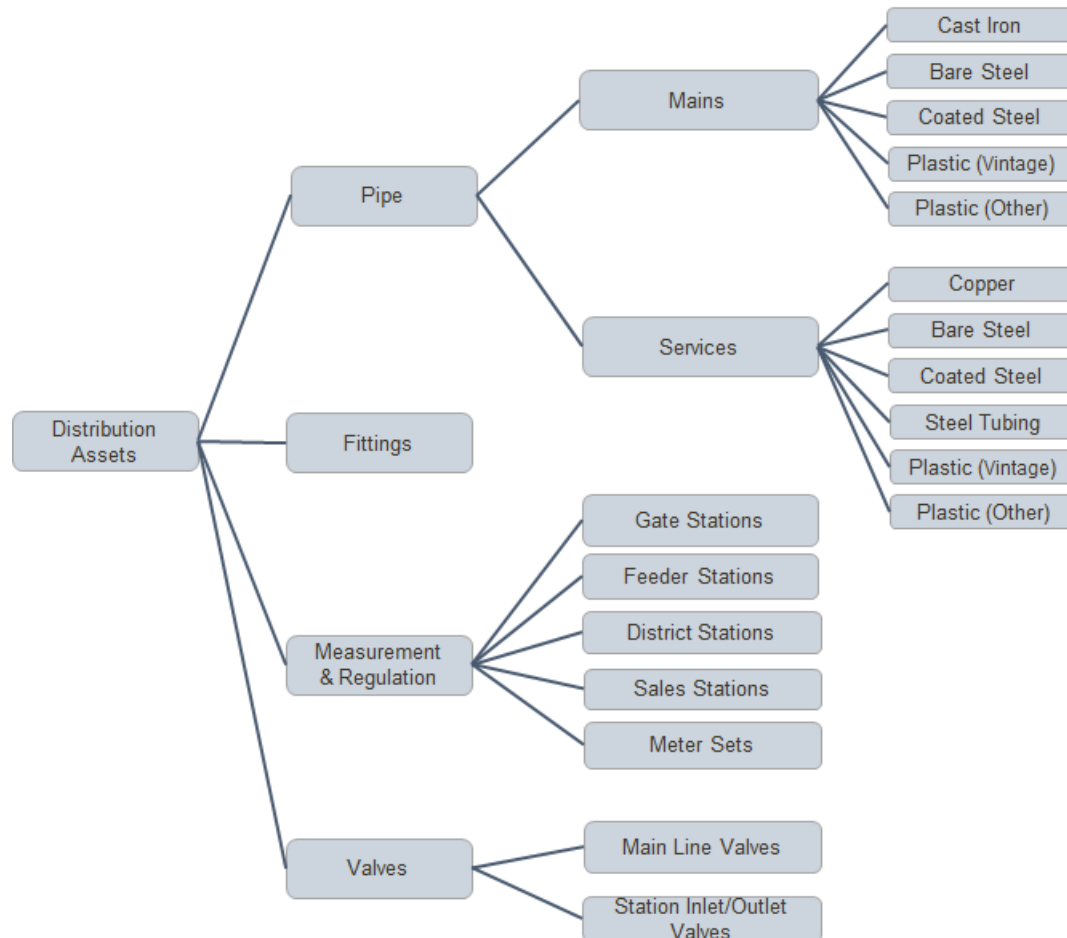


Figure 2 - Asset Taxonomy

Based on the Asset hierarchy above, Table 1 below quantifies the assets, as of March 2012.

Distribution Asset Classes		Quantity
Pipe		
Mains (#kms)		35,181
	Cast Iron	138
	Bare Steel	17
	Coated Steel	12,773
	Plastic - Vintage	3,689
	Plastic - Other	18,559
	Unclassified	5
Service Lines (#)		1,947,325
	Copper	6,754
	Bare Steel	30,714
	Coated Steel	159,744
	Steel Tubing	423
	Plastic - Vintage	284,892
	Plastic - Other	1,463,535
	Unclassified	1,263
Measurement & Regulation		
Gate Stations (#)		47
Feeder Stations (#)		19
District Stations(#)		4,613
Sales Stations (#)		9,391
Customer Meter Sets (#)		2,025,872
Main & Station Valves		
Main Line Valves (#)		19,884
Station Inlet/Outlet Valves (#)		9,273
Unclassified		1,225

Table 1 - Asset Inventory

A common reality faced by the natural gas industry is legacy records where some information about the asset that would be instructive to have is not available. In many cases this is because collection of specific types of data was not part of the records collection standard at the time of installation.

Where adequate information was not available to accurately classify the assets, they have been labeled “Unclassified”.

Although fittings are recognized as an important element of EGD’s asset inventory, historically these have not been recorded as separate assets, but rather associated with pipe assets. This makes it difficult to determine a precise inventory of these assets.

3.2 Geographic Distribution of Assets

EGD's franchise area is divided into seven administrative areas (Areas 10, 20, 30, 40, 50, 60, 80) as shown below. All of EGD's distribution assets reside in these areas.

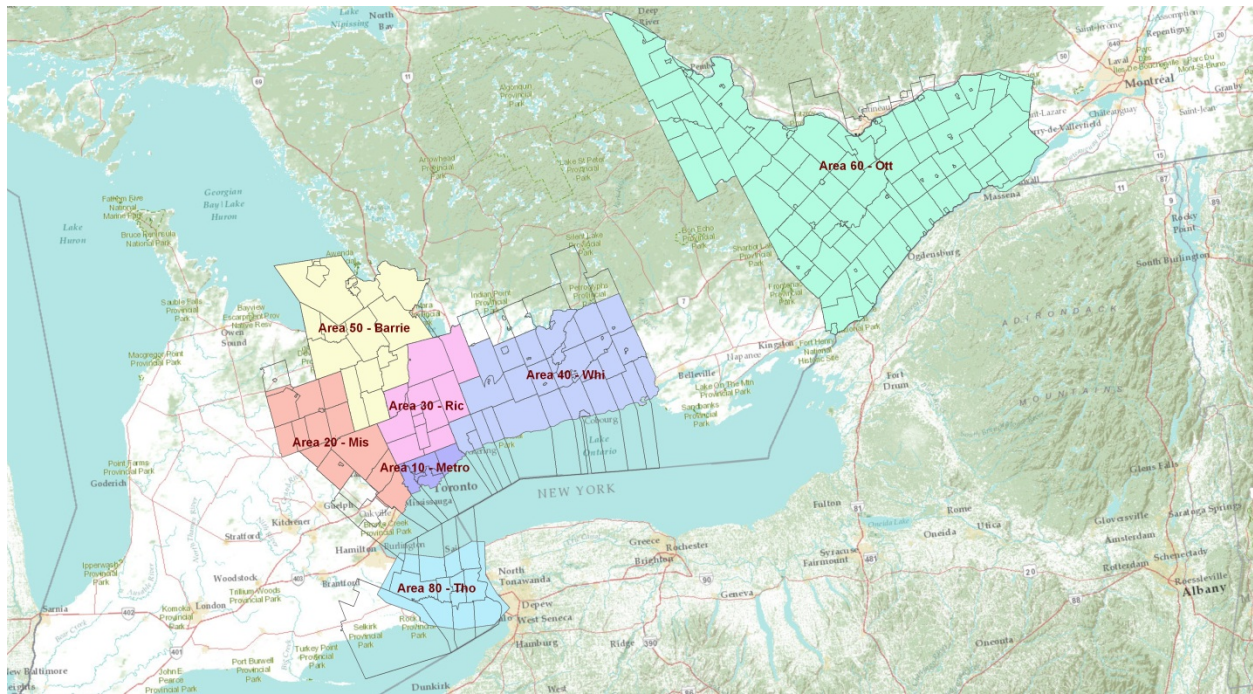


Figure 3 - EGD's Geographic Organization

Area 10 covers Toronto. Areas 20, 30, 40 and 50 cover the remainder of the Greater Toronto area. Area 60 covers the Ottawa region, and Area 80 covers the Niagara region.

In some cases, asset requirements can vary by area based on historic and future customer growth trends, historic regional practices, geographical conditions such as topography, soil conditions, and other factors.

The asset inventory outlined in Table 1 Asset Inventory is an aggregate of assets by asset class across all areas.

3.3 Understanding Assets by Age

EGD, as Ontario's oldest natural gas utility, has assets of varying age. Understanding the in-service date of the assets is important since materials degrade, and the performance characteristics of the assets can change over time. This understanding can help inform the need, scope and timing of replacement programs.

Histograms of Mains, Services and Main/Station Valves based on age follow.

Mains:

EGD's distribution system has over 35,000 km of mains. Based on when these assets were installed and their material type, there are different generations or distributions of mains as shown in the chart below.

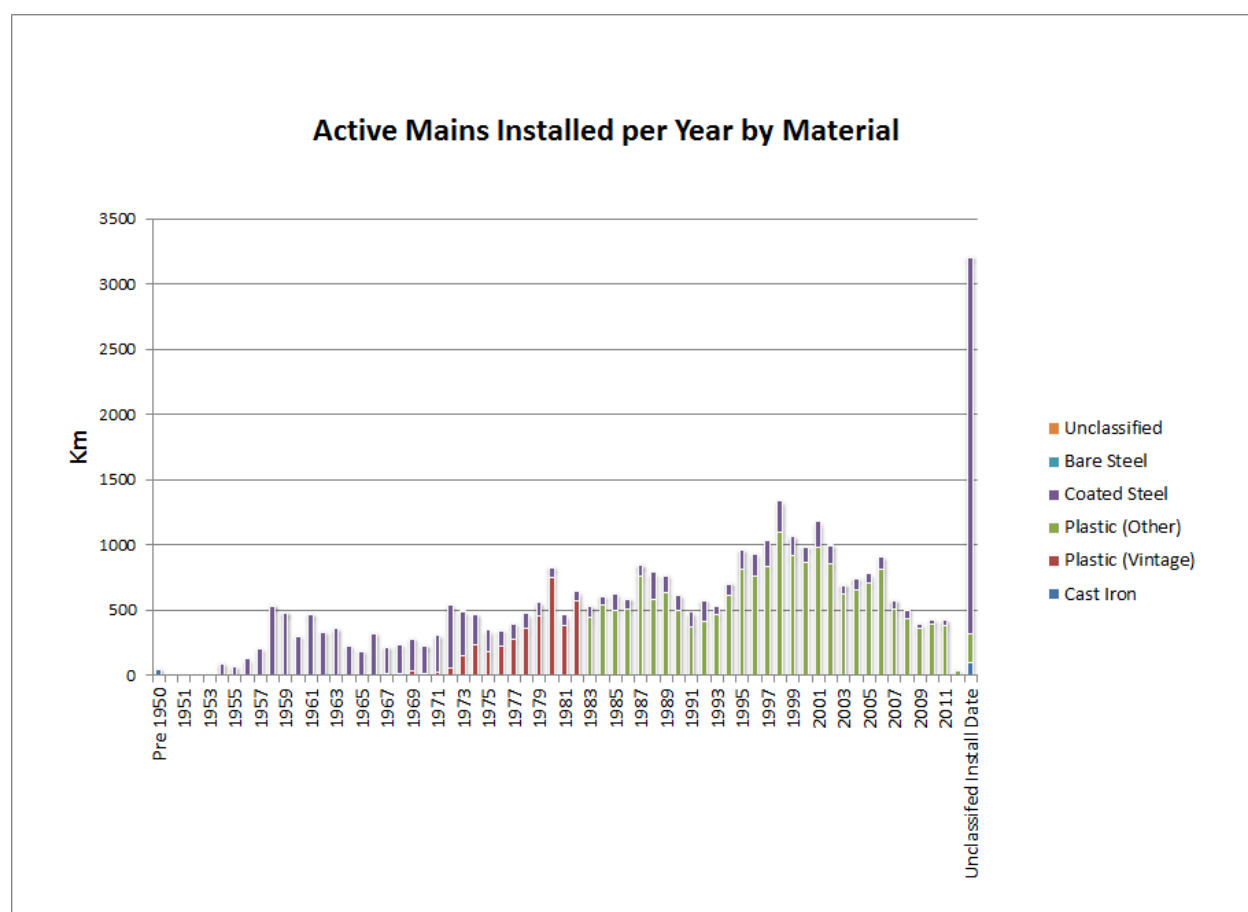


Chart 4 - Active Mains Installed by Year by Material

Services:

There are approximately 1.9 million active services across the franchise area. Similar to mains, there are several generations or distributions of services, based on their material type as shown in the chart below.

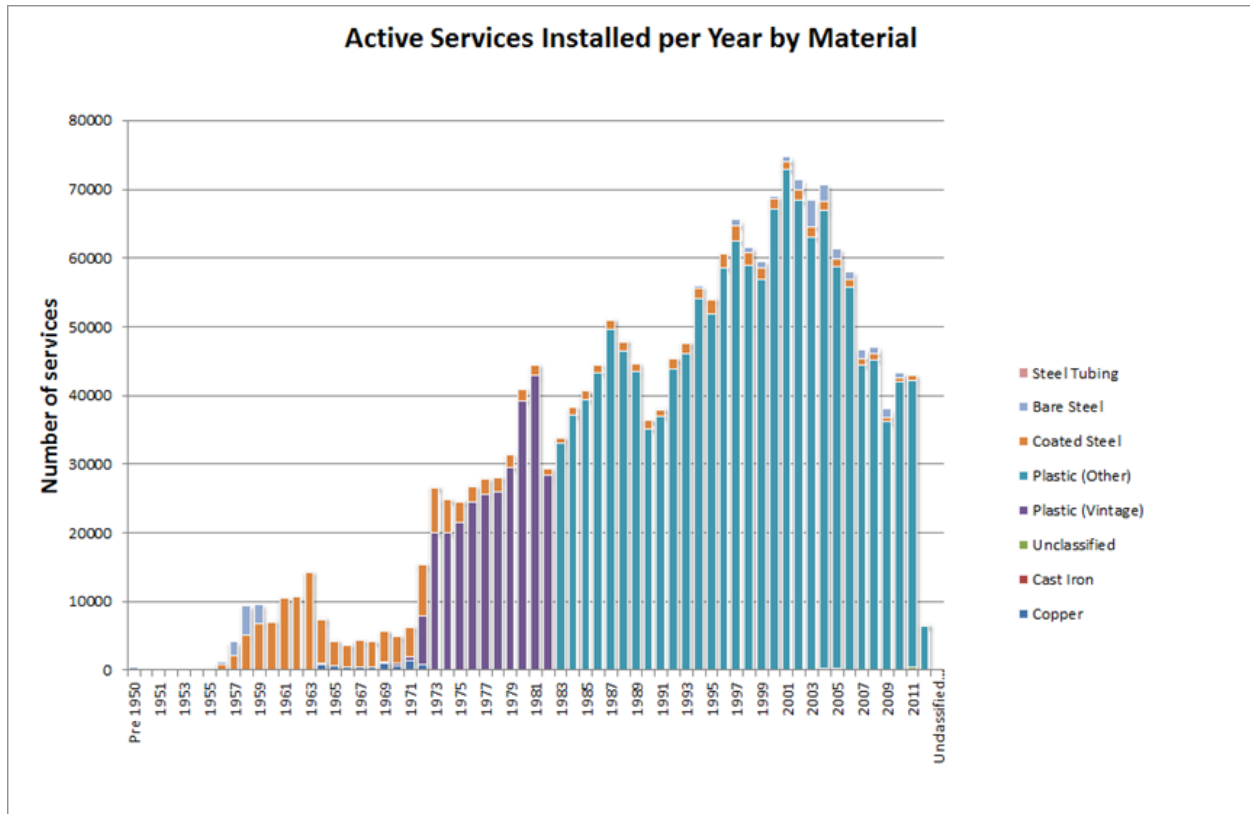


Chart 5 - Active Services Installed by Year by Material

Main and Station Valves

There are approximately 34,000 active main and station valves across the franchise area. Approximately 95% of these valves are steel, with the remaining 5% being plastic. These valves are located in system pressure regulating facilities, in-line in mains, as well as at customer sales stations. Similar to mains and services, there are several generations or distributions of valves as depicted in the chart below.

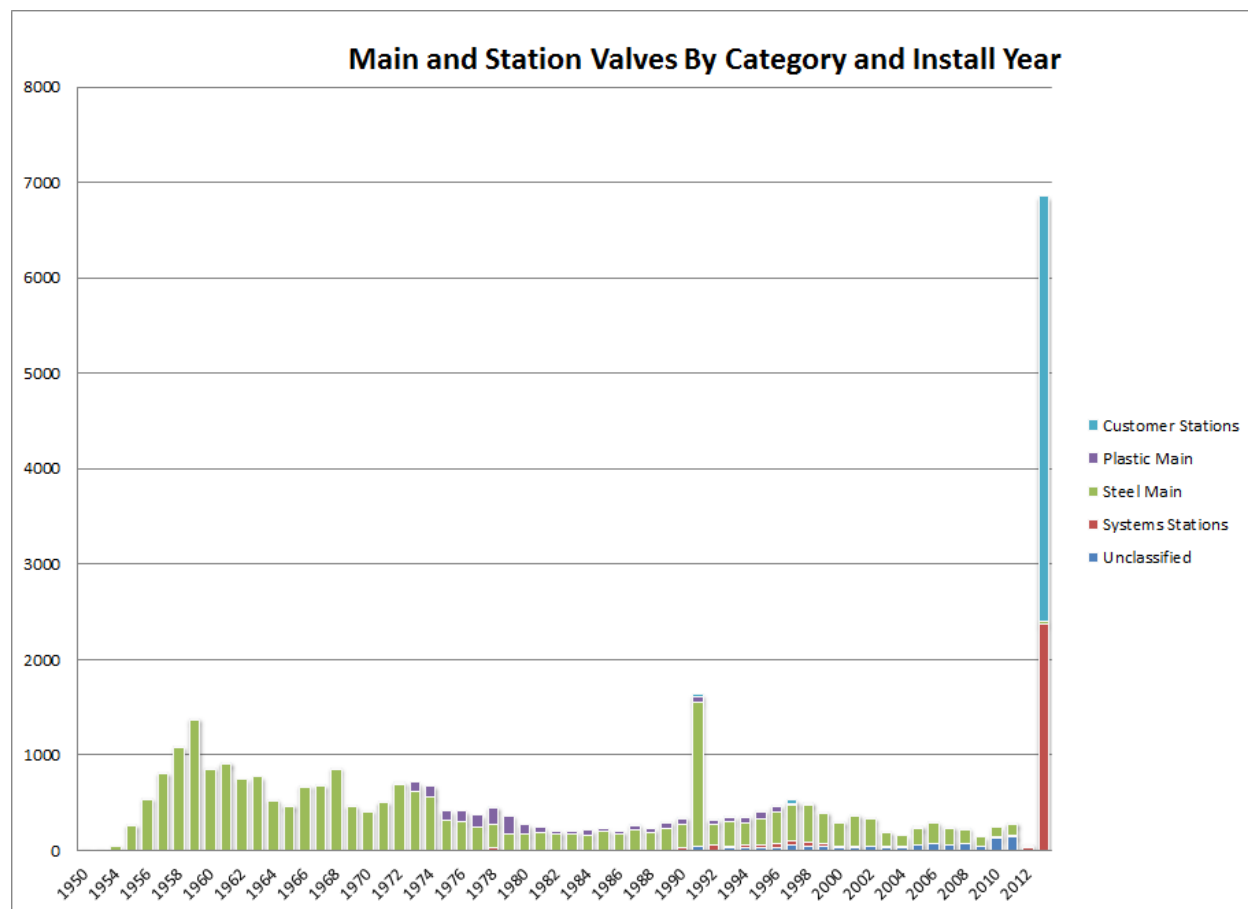


Chart 6 - Main and Station Valves by Category and Install Year

4. EGD's Asset Management Principles

As part of EGD's Asset Management System, several guiding principles have been developed. The principles are expressed as Objectives, Policies, and Strategies. These principles have been used to guide the development of the Asset Plan, more specifically with respect to the identification of requirements, their prioritization, and definition of plans to address requirements.

- Asset Management Objectives help align asset investments with the Company's strategic priorities
- Policies define the key considerations that should apply to ensure the effective management of the Company's assets
- Strategies define the high level approach to meet the Asset Management Objectives, consistent with the Asset Management Policies

4.1 Asset Management Objectives

The overall purpose of EGD's Asset Management System is to optimize the long term value of its distribution assets by achieving an effective balance of Risk, Operational Performance and Cost.

The specific objectives are:

- Safety : Continue to drive to zero incidents and property damage
- Reliability : Proactively identify and address asset related risks that can result in disruption of gas distribution service to customers
- Growth: Expand the distribution system to meet the growth in EGD's customer base in a sustainable manner
- Cost Effectiveness : Make prudent asset investment decisions while being mindful of rate payer impacts
- Environmental stewardship : Effectively manage the lifecycle of the Company's assets to reduce their environmental impact
- Compliance : Meet all applicable industry and regulatory requirements related to management of assets

4.2 Asset Management Policies

Enbridge Gas Distribution is committed to the safe, reliable, cost effective and environmentally responsible provision of gas distribution and services. At the core of this commitment is the effective stewardship of the company's distribution assets. It is through these assets that the company ultimately provides value to all of its stakeholders.

The following are policies that EGD has established to effectively manage its distribution assets:

1. The Company shall use the Asset Manager – System Operator model as the fundamental organizational construct to manage and operate its assets. This model provides a clear separation of accountabilities such that the Asset Manager is primarily responsible for decisions related to asset investments, while the System Operator executes building and operating the assets in the most efficient manner
2. The Company is committed to making all asset-related decisions on the basis of striving to achieve the appropriate balance of Risk, Operational Performance and Cost
3. The Company is committed to the regular assessment of risks associated with its assets, and ensuring that these risks are effectively managed
4. The Company acknowledges that asset information is critical to the effective management of its assets. Therefore, the organization shall ensure that its processes, systems and controls collectively strive to deliver complete, timely, accurate, verifiable and accessible asset information
5. The Company shall have an Asset Plan that is consistent with its key priorities. This plan will be reviewed, revised and ratified on an annual basis
6. The Company is committed to managing every stage in the lifecycle of its assets in compliance with all applicable laws and regulations, industry codes of practice, and internal company policies

4.3 Asset Management Strategies

The following table summarizes the high level strategies that have been developed by Management to address the asset requirements included in this Asset Plan.

Type of Investment	Strategies
Customer Additions	• The strategy for customer additions is to add all customers in existing and new communities that meet feasibility guidelines
Reinforcements	• Reinforce existing distribution assets to ensure that the system has the capacity to reliably meet current and future customer load demand • Ensure security of supply by enhancing the flexibility of the system to address disruptions in upstream supply or failures with major components of the system
System Integrity & Reliability	• Replace existing assets that are near the end of their useful life • Conduct studies to improve understanding of the condition of specific classes of assets where risks have been identified. Leverage these studies to develop mitigation plans, including risk prioritized replacement, repair or monitoring programs • Comply with all applicable rules and regulations related to system integrity and safety • Enhance the integrity of distribution asset records to reduce operational risk • Enhance our understanding of the condition of our critical assets by expanding the scope of inline inspection programs to include select XHP lines operating over 20% Specified Minimum Yield Strength (SMYS), consistent with current industry best-practices • Enhance the safety and reliability of our critical assets by verifying the Maximum Allowable Operating Pressure (MAOP) of targeted lines • Protect the distribution assets from damages through enhanced monitoring, installation of protective equipment, and the implementation of programs to address specific risks such as sewer laterals

	• Enhance the capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions • Continue with existing programs already in place to address operational and asset risks and compliance requirements
Relocations	• The need to relocate EGD assets is primarily driven by external parties such as municipal authorities. EGD's strategy is to meet these relocation requirements in the most cost-effective way while recovering costs allowed by franchise and other agreements

Table 2 - Asset Management Strategies

5. Asset Management Requirements

This section of the Asset Plan defines:

- The known, and anticipated requirements related to our assets
- The approach to fulfill these requirements, consistent with the Company's Asset Management Objectives, Policies and Strategies
- Estimates of the financial investments needed to meet these requirements

5.1 Overview of Requirements

The following diagram depicts the four primary types of asset-related capital investments that are required over the term of the asset plan.

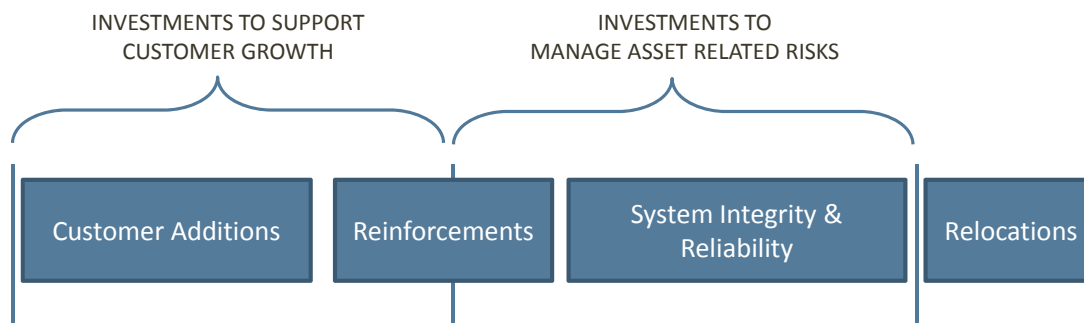


Figure 4 - Types of Asset Related Capital Investments

Customer Additions:

EGD is obligated to meet its customer growth demand by attaching customers that meet feasibility guidelines. Each year, there are several thousand Customer Addition projects that accomplish this. Customer Addition projects typically involve installing new segments of mains, installing services, and related meter sets.

In some cases, new Measurement & Regulation equipment such as stations need to be added or existing equipment needs to be upgraded due to increased loads.

Reinforcements:

Reinforcements increase the capacity and operating flexibility of the distribution system. They primarily refer to Mains. These projects are driven by Customer Growth and/or System Integrity & Reliability requirements.

System Integrity & Reliability:

In order to ensure safety and reliability, assets need to be effectively monitored, and risks need to be addressed in a proactive manner. There are a number of programs currently in place that address known risks. As new risks are identified, existing programs may need to be amended, or new programs may need to be established. Before amending existing programs or establishing new programs, studies are necessary to validate the requirements.

Relocations:

Distribution assets generally need to be relocated for reasons such as road-widening and other municipal or third party construction projects. The requirement and timing for these Relocation projects are primarily driven by municipal authorities. EGD recovers a portion of the capital investments for such projects.

5.2 Customer Additions

Requirements

EGD has experienced significant customer growth in its franchise area. This growth is expected to continue in the future.

The customer additions forecast at EGD is developed using a number of information sources:

1. Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
2. Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment, and mortgage rates
3. Projections developed by external consultants specializing in population growth forecasting, as well as municipality long term plans

The following chart depicts the historic customer additions and the forecast for the term of the Asset Plan.

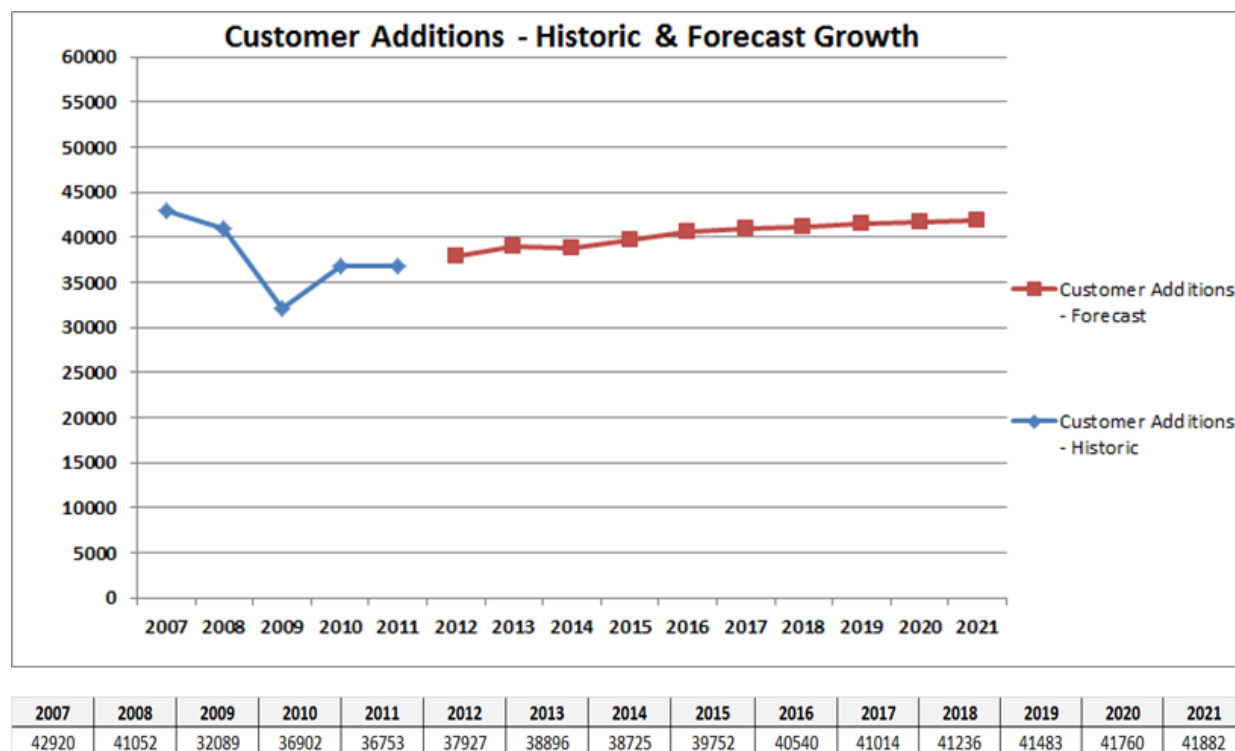


Chart 7 - Customer Additions: Historic & Forecast Growth

The pace of customer growth is expected to continue from 2012 to 2021.

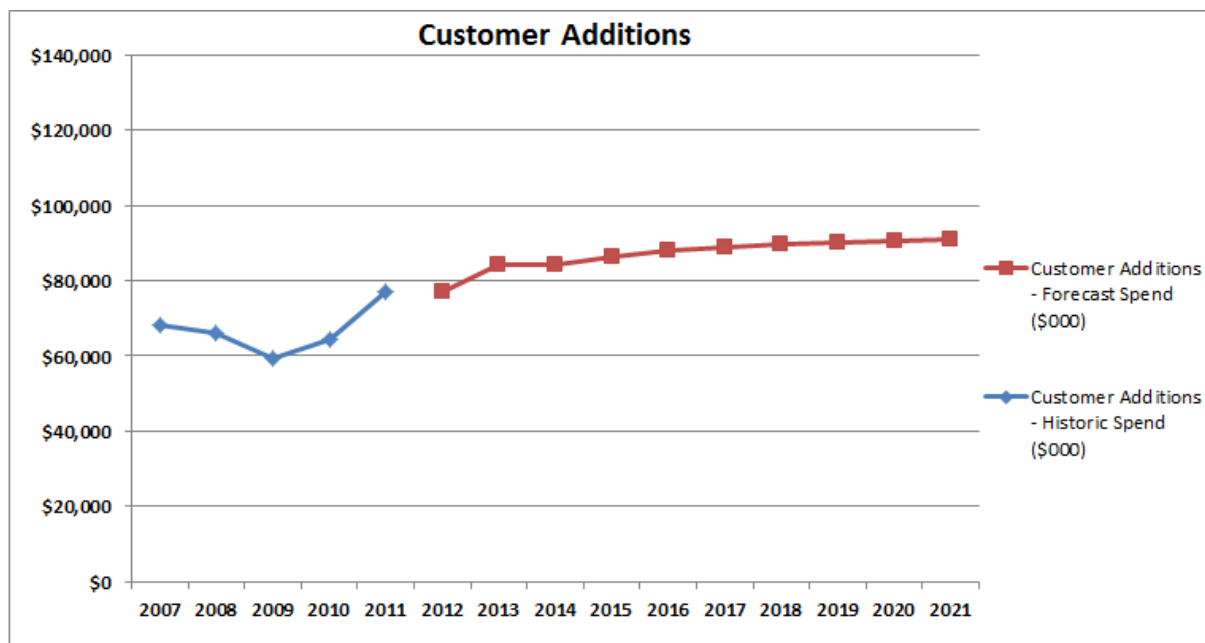
- The majority of these customer additions will be for new residential customers in existing communities
- Toronto (Area 10) will see approx. 10% of the annual customer additions. The Niagara region (Area 80) is expected to see the smallest share of these customer additions – under 3%. The Ottawa region (Area 60) will see approximately 20%. Over 60% of the new customer additions are expected to take place in the GTA, representing Areas 20, 30, 40 and 50. This in turn will inform when and where reinforcements to the system may be required

Implementation Plan & Estimated Capital Investments

Generally, there are three components of capital investments needed to support the customer additions requirements:

- Installation costs related to Mains, Services and Meters
- Material costs related to Mains, Services and Meters
- Cost related to Measurement & Regulation equipment required to support customer growth

The following chart depicts the historic capital spend on customer additions and the forecast spend for 2012-2021 based on the customer addition forecast numbers.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
\$68,323	\$66,132	\$59,257	\$64,226	\$77,116	\$76,982	\$84,413	\$84,036	\$86,264	\$87,974	\$89,003	\$89,485	\$90,021	\$90,622	\$90,887

Chart 8 - Customer Additions: Historic & Forecast Capital Spend

5.3 Reinforcements

Requirements

Reinforcement requirements are primarily driven by Customer Growth and System Integrity & Reliability considerations.

As part of the Asset Planning process, network analysis is performed to establish the need and timing for reinforcements within each of the operating areas that make up EGD's franchise area as defined in Section 3.2 - Geographic Distribution of Assets.

Routine Reinforcements:

Reinforcements to the distribution system are required to ensure that the system can continue to reliably deliver the gas load required by existing and new customers.

The basic objective at EGD for network design is that the system must meet anticipated peak demand at a temperature-dependent design condition. All load additions to the system are modeled based on this design temperature.

To determine the timing of the necessary reinforcements, yearly load additions are modeled by geographical area. Reinforcements are specified based on the system's ability to meet minimum system pressures at key control locations. The ultimate design is based on a minimum of 10 years of customer growth with due consideration given to 20 years of growth, security of supply, and operational flexibility.

This analysis yields the specific reinforcement projects in the following table. In addition, other reinforcements that have not been previously identified will be required from time to time. A provision has been made in the implementation plan to account for these.

The following is a summary of the known requirements by area as of December 2011.

AREA	PROJECT DESCRIPTION
Area 10	4.2 km of HP on Bathurst from Steeles to Sheppard & 3.5 km E on Sheppard to Bayview plus a new HP to IP District Station
	4.0 km of NPS 12" HP from Node 1802294 to 1802241 to 1801503, On Oriole from Roselawn to Kilbarry to Roxborough
	4.5 km of NPS 12" HP from Node 1803252 to 1890057, On Spadina from MacPherson to Lakeshore
	3.5 km of NPS 16" HP Steel Main from New Bayview Station to existing NPS 24" HP Main at Avenue /McPherson
	2.5 km of NPS 16" HP from Node 1803363 to 1900043 from Victoria Park on Dawes to Woodbine & Strathmore
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd
	Install approximately 1000m of NPS 6 ST HP on Hurontario from Steeles to County Court
	Install approx 5 km of NPS 8 XHP from the newly elevated Bondhead line northbound to increase the pressure in Dundalk and Shelburne
	Replace 1181.5m of NPS 4 with NPS 8 on Hurontario, from Steeles to County Court
	Replace 1279.9m NPS 4 with NPS 8 from 1803184 to 1802257
	Install 253.7m NPS 6 connect 21820195 to NPS 24 PineValley line (Mississauga Rd close to CNR)
Area 30	Scarborough Reinforcement - Phase 2 Station Installation
	Install 1200m NPS 12 HP main in new development to avoid construction on Steels and crossing of Rouge
	Install approximately 2000m of XHP NPS 8 ST on Carrville from Bathurst to Yonge
	Install approximately 1400m of NPS 4 ST on Keele from McNaughton to Teston
	Install 7400m of NPS 16 on Woodbine, from Victoria Square to Bloomington
	Install 1050m of NPS 4 on 6th Concession, from Silver Spring Cres to Old Stouffville Sdrd
	Install 200m of NPS 4 on Holburn, from Leslie to Woodbine
	Install 570m of NPS 8 on 16th Ave, from Granton to Spadina
	Install 1200m of NPS 8 on Hwy 7, from stn# 33027 to Woodbine
	Install 2200m of NPS 8 on 19th Ave, from 9th Line to Reesor
	Install 6500m of NPS 16 on Woodbine, from Bloomington to St. Johns Sdrd
	Install 6800m of NPS 8 on Glenwoods/Warden, from Woodbine to Bethel Sdrd

AREA	PROJECT DESCRIPTION
Area 40	Peterborough Reinforcement Phase 1 - Install approximately 1.5 km of NPS 8
	Peterborough Reinforcement Phase 2 - Install approximately 2.4 km of NPS 8 on Preston from the terminus of Phase 1 north to Mount Pleasant at Hwy 7
	Peterborough Reinforcement Phase 3 - Install 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant to Lily Lake
	Kingston Road Reinforcement, install 2.4 km of NPS 4 ST XHP from Lakeridge to Salem with Station
	Approx 8 km NPS 12 XHP, to support OPG and Durham EFW
	Install 300m of NPS 4 ST HP on Whites from south of HWY 401 to Oklahoma Drive, Pickering
	Replace 1.8 km of NPS 12 XHP main with 1.8km of NPS 16 XHP from Oshawa gate to Conlin and Wilson
	NPS 8XHP reinforcement - Kawartha Ethanol Reinforcement - Phase 2 & 3
	Install 2.8 km of NPS 8 ST HP main from ex NPS 8 HP main on at Brock & Kingston, Pickering to Ex.NPS 6 ST HP main at Westney and Kingston Rd in Pickering
Area 50	Alliston Reinforcement, 9 km NPS 8
	Angus Reinforcement
	Alliston Reinforcement Phase 2, 1.5 km NPS 8
	Stayner Second source, NPS 4 XHP with Station
	Alliston Reinforcement Phase 3, 2.8 km NPS 8
	Install 400m of NPS 4 on Hwy 27, from Hwy 9 south, with XHP to HP station Schomberg
	Alliston Reinforcement Phase 4, 3 km NPS 6
Area 60	Approx. 900m OF NPS 8 ST XHP River Crossing @ Woodroffe & Hwy.# 16 towards River Rd
	Mitch Owens Rebuild and install 2 km NPS 4 XHP
	Ottawa Innes Road Replacement - Replace 3.0 km of NPS 8 main with NPS 12, and remove an existing system bottleneck while ensuring a mandated inspection or elimination of high stress pipeline is completed by Dec 2013
	Pressure elevate HP network 6597 feeding Richmond to XHP, approx. 5300m of NPS 4 ST
	Approx. 6700m of NPS 20 ST HP pipe from Greenbank to Rideau Heights
Area 80	Chippawa Creek Road Reinforcement, Replace approx. 400m of NPS 6 ST HP with NPS 12 ST HP

Table 3 - Routine Reinforcements

Major Reinforcements:

In addition to the routine reinforcements, from time to time major reinforcements of the extra-high pressure grid mains that form the major backbone of the distribution system are required to further support customer growth and address significant system reliability and security of supply issues. These reinforcements are characterized by their size and complexity, and do not arise as frequently as the routine reinforcements.

Analysis of the supply chain and failure risks within the supply chain has indicated the potential for significant customer outages under certain upstream and downstream upset conditions affecting areas of high population densities, including the GTA and the Ottawa region.

This has led to the identification for the need of two major reinforcements in the 10-year planning horizon of this Asset Plan:

- The GTA Project will address these concerns for the Greater Toronto Area
- The Ottawa Reinforcement will address similar concerns for the Ottawa area

While these projects have been included within this Asset Plan, further details will be provided in the Leave-To-Construct applications that will be filed for each of these projects later in 2012.

The following is a summary of the Major Reinforcements.

PROJECT	PROJECT DESCRIPTION
GTA Project	Upgrading the XHP grid system in the Greater Toronto Area to meet load growth, ensure continued reliability and enable access to lower cost natural gas supplies
Ottawa Reinforcement	Ottawa Reinforcement Pre-Engineering
	Approx. 19300m of NPS 24 ST XHP pipe from Richmond Gate Station, North easterly to Greenbank
	Ottawa Reinforcement additional construction costs

Table 4 - Major Reinforcements

Implementation Plan & Estimated Capital Investments

Based on the reinforcement requirements, an implementation schedule was developed for reinforcement projects over the term of the Asset Plan. An estimate was also developed for the capital spend required for each of the projects. The following is a summary of this schedule.

Routine Reinforcements:

AREA	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) (\$'000)
Area 10	4.2 km of HP on Bathurst from Steeles to Sheppard & 3.5 km E on Sheppard to Bayview plus a new HP to IP District Station	2018							A-10				\$9,000
	4.0 km of NPS 12" HP from Node 1802294 to 1802241 to 1801503, On Oriole from Roselawn to Kilbarry to Roxborough	2018							A-10				\$6,000
	4.5 km of NPS 12" HP from Node 1803252 to 1890057, On Spadina from MacPherson to Lakeshore	2019								A-10			\$7,000
	3.5 km of NPS 16" HP Steel Main from New Bayview Station to existing NPS 24" HP Main at Avenue /McPherson	2017						A-10					\$20,000
	2.5 km of NPS 16" HP from Node 1803363 to 1900043 from Victoria Park on Dawes to Woodbine & Strathmore	2019								A-10			\$5,000
Area 20	Install approximately 2500m of 4" XHP on Mayfield east to Airport Rd	2012	A-20										\$1,000
	Install approximately 1000m of NPS 6 ST HP on Hurontario from Steeles to County Court	2012	A-20										\$750
	Install approx 5 km of NPS 8 XHP from the newly elevated Bondhead line northbound to increase the pressure in Dundalk and Shelburne	2012	A-20										\$1,900
	Replace 1181.5m of NPS 4 with NPS 8 on Hurontario, from Steeles to County Court	2017						A-20					\$1,000
	Replace 1279.9m NPS 4 with NPS 8 from 1803184 to 1802257	2019								A-20			\$1,000
	Install 253.7m NPS 6 connect 21820195 to NPS 24 PineValley line (Mississauga Rd close to CNR)	2020									A-20		\$250
Area 30	Scarborough Reinforcement - Phase 2 Station Installation	2012	A-30										\$751
	Install 1200m NPS 12 HP main in new development to avoid construction on Steels and crossing of Rouge	2012	A-30										\$1,000
	Install approximately 2000m of XHP NPS 8 ST on Carrville from Bathurst to Yonge	2013		A-30									\$1,900
	Install approximately 1400m of NPS 4 ST on Keele from McNaughton to Teston	2012	A-30										\$560
	Install 7400m of NPS 16 on Woodbine, from Victoria Square to Bloomington	2014			A-30								\$15,000
	Install 1050m of NPS 4 on 6th Concession, from Silver Spring Cres to Old Stouffville Sdrd	2016					A-30						\$400
	Install 200m of NPS 4 on Holburn, from Leslie to Woodbine	2017						A-30					\$600
	Install 570m of NPS 8 on 16th Ave, from Granton to Spadina	2018							A-30				\$600
	Install 1200m of NPS 8 on Hwy 7, from stn# 33027 to Woodbine	2018							A-30				\$800
	Install 2200m of NPS 8 on 19th Ave, from 9th Line to Reesor	2018							A-30				\$1,600
	Install 6500m of NPS 16 on Woodbine, from Bloomington to St. Johns Sdrd	2019								A-30			\$14,000
	Install 6800m of NPS 8 on Glenwoods/Warden, from Woodbine to Bethel Sdrd	2020									A-30		\$5,000

AREA	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) (\$000)
Area 40	Peterborough Reinforcement Phase 1 - Install approximately 1.5 km of NPS 8	2012	A-40										\$485
	Peterborough Reinforcement Phase 2 - Install approximately 2.4 km of NPS 8 on Preston from the terminus of Phase 1 north to Mount Pleasant at Hwy 7	2012	A-40										\$1,900
	Peterborough Reinforcement Phase 3 - Install 1.9 km of NPS 8 ST XHP on HWY 7 from north of Mt Pleasant to Lily Lake	2014			A-40								\$1,500
	Kingston Road Reinforcement, install 2.4 km of NPS 4 ST XHP from Lakeridge to Salem with Station	2013		A-40									\$1,000
	Approx 8 km NPS 12 XHP, to support OPG and Durham EFW	2014			A-40								\$12,000
	Install 300m of NPS 4 ST HP on Whites from south of HWY 401 to Oklahoma Drive, Pickering	2015				A-40							\$200
	Replace 1.8 km of NPS 12 XHP main with 1.8km of NPS 16 XHP from Oshawa gate to Conlin and Wilson	2016					A-40						\$3,500
	NPS 8XHP reinforcement - Kawartha Ethanol Reinforcement - Phase 2 & 3	2012	A-40										\$2,200
	Install 2.8 km of NPS 8 ST HP main from ex NPS 8 HP main on at Brock & Kingston, Pickering to Ex.NPS 6 ST HP main at Westney and Kingston Rd in Pickering	2017						A-40					\$2,500
Area 50	Alliston Reinforcement, 9 km NPS 8	2012	A-50										\$4,660
	Angus Reinforcement	2012	A-50										\$6,000
	Alliston Reinforcement Phase 2, 1.5 km NPS 8	2014			A-50								\$1,150
	Stayner Second source, NPS 4 XHP with Station	2013		A-50									\$750
	Alliston Reinforcement Phase 3, 2.8 km NPS 8	2015				A-50							\$1,989
	Install 400m of NPS 4 on Hwy 27, from Hwy 9 south, with XHP to HP station Schomberg	2017						A-50					\$500
	Alliston Reinforcement Phase 4, 3 km NPS 6	2019								A-50			\$1,917
Area 60	Approx. 900m OF NPS 8 ST XHP River Crossing @ Woodroffe & Hwy.# 16 towards River Rd	2012	A-60										\$1,600
	Mitch Owens Rebuild and install 2 km NPS 4 XHP	2012	A-60										\$950
	Ottawa Innes Road Replacement - Replace 3.0 km of NPS 8 main with NPS 12, and remove an existing system bottleneck while ensuring a mandated inspection or elimination of high stress pipeline is completed by Dec 2013	2013		A-60									\$6,000
	Pressure elevate HP network 6597 feeding Richmond to XHP, approx. 5300m of NPS 4 ST	2017						A-60					\$200
	Approx. 6700m of NPS 20 ST HP pipe from Greenbank to Rideau Heights	2018							A-60				\$10,000
Area 80	Chippawa Creek Road Reinforcement, Replace approx. 400m of NPS 6 ST HP with NPS 12 ST HP	2013		A-80									\$400
Contingency for Reinforcements	Contingency to account for additional Reinforcement requirements that might come up within each year	2012-2021											\$18,250

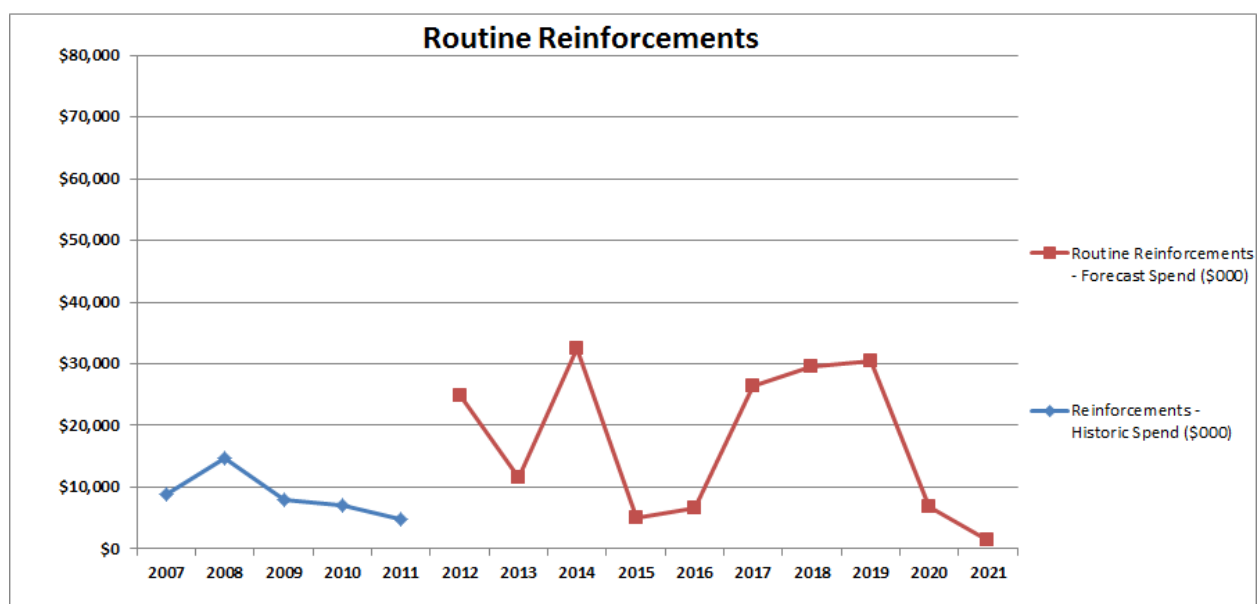
Figure 5 - Routine Reinforcements: Implementation Schedule & Cost

Major Reinforcements:

PROJECT	PROJECT DESCRIPTION	Dates	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) (\$000)
GTA Project	Upgrading the XHP grid system in the Greater Toronto Area to meet load growth, ensure continued reliability and enable access to lower cost natural gas supplies	2012-2015	A-10										\$548,144
Ottawa Reinforcement	Ottawa Reinforcement Pre-Engineering	2012	A-60										\$1,500
	Approx. 19300m of NPS 24 ST XHP pipe from Richmond Gate Station, North easterly to Greenbank	2013		A-60									\$30,000
	Ottawa Reinforcement additional construction costs	2014			A-60								\$13,246

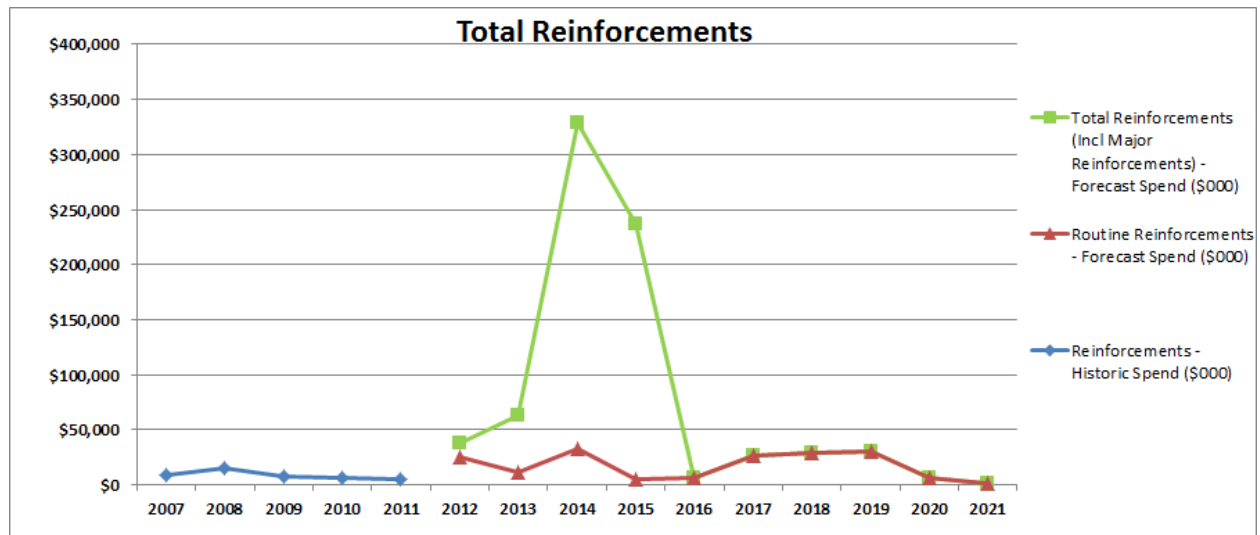
Figure 6 - Major Reinforcements: Implementation Schedule & Cost

The charts below depict the historic and forecast capital spend for routine reinforcements alone, and the total reinforcements within the term of the Asset Plan.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
\$8,795	\$14,710	\$8,061	\$7,054	\$4,742	\$24,756	\$11,550	\$32,400	\$4,939	\$6,650	\$26,300	\$29,500	\$30,417	\$6,750	\$1,500

Chart 9 - Routine Reinforcements: Historic & Forecast Capital Spend



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Routine Reinforcements (\$000)						\$24,756	\$11,550	\$32,400	\$4,939	\$6,650	\$26,300	\$29,500	\$30,417	\$6,750	\$1,500
Total Reinforcements (\$000)	\$8,795	\$14,710	\$8,061	\$7,054	\$4,742	\$37,883	\$62,667	\$329,146	\$236,839	\$6,650	\$26,300	\$29,500	\$30,417	\$6,750	\$1,500

Chart 10 - Total Reinforcements: Historic & Forecast Capital Spend

At this time, the forecast of costs for the GTA project for 2014 and 2015 are still being refined, and the estimates are only available as a range. The chart above assumes the mid-point of the estimated range.

5.4 System Integrity & Reliability

The Need for Integrity Management

A critical responsibility in managing a natural gas distribution system is to understand potential threats to the safety and reliability of the system. Threats to the system can manifest risks (defined as a combination of likelihood and impact), which if not appropriately managed, can lead to serious incidents.

In general, risks associated with gas distribution assets occur when there is a loss of containment of gas from the system. Two basic characteristics of natural gas are that it is lighter than air and when it is released from containment, it will follow the path of least resistance. In most cases, a release of gas will result in the gas escaping to the atmosphere with minor consequences. However, if the gas ignites or if the release of gas follows a path of least resistance to a confined space, increasing the probability of ignition, serious consequences can result. There are several threats to a gas distribution system, such as third party damages, corrosion or degradation, equipment malfunction, etc. which can result in a loss of containment of gas from the system.

In terms of System Integrity, EGD must meet its regulatory obligation to comply with the CSA Z662 Oil and Gas Pipeline Systems standard. EGD will be required to comply with Annex N of the 2011 edition of this standard, Integrity Management Programs and Activities, when the Technical Standards and Safety Authority (TSSA) adopts the standard, likely later this year. At this time, EGD is required to comply with a form of Annex N that is included in the current standard.

The following figure depicts the requirements of Annex N. To ultimately comply with this regulation, EGD must plan, assess, act, measure and improve its management of integrity on a continuous improvement cycle.

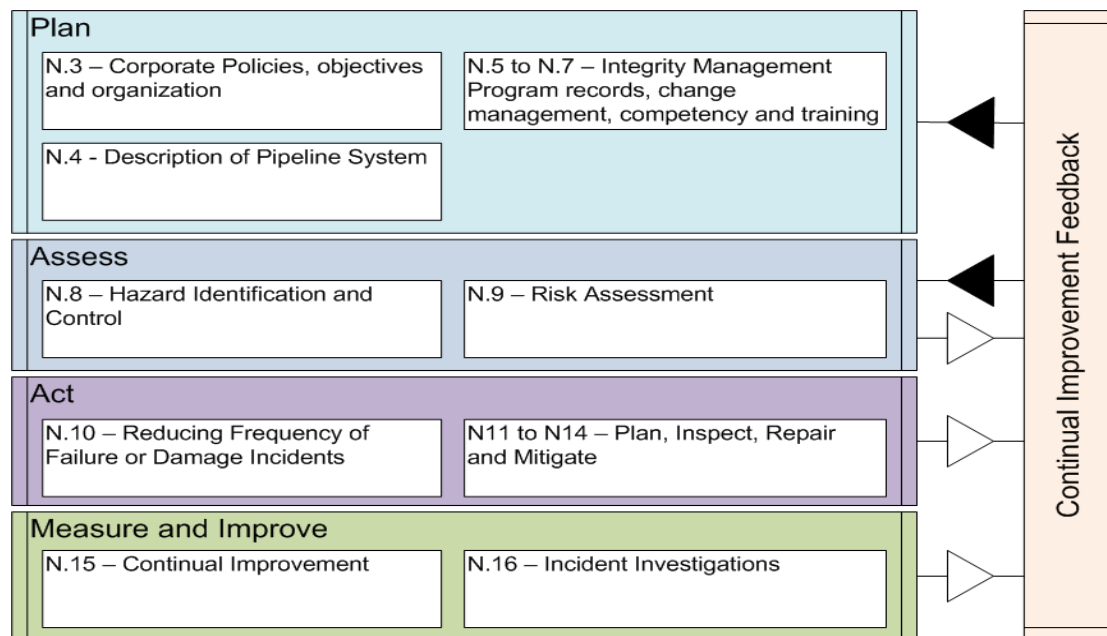


Figure 7 - Elements of CSA Z662 Annex N

In addition, recent events in the natural gas industry, such as the tragic San Bruno explosion in September 2010, the Philadelphia explosion in January 2011, and the Allentown explosion in February 2011, have resulted in increased focus on public safety. Lessons learned from these tragedies are expected to lead to changes in legislation and standards as the industry and regulators seek to minimize the chances of incidents occurring in the future.

EGD's Evolving Integrity Management Practice

Threats to the gas distribution system have existed from the inception of the industry. EGD has practiced a form of asset management to address integrity issues throughout its history. Integrity Management practices have focused on a wide variety of mitigation programs, including ongoing leak detection and damage prevention programs supported by effective emergency response processes to reactively respond to leaks and damages. In some cases, Integrity Management practices have been directed at proactively addressing specific assets that posed significant risks such as cast iron or bare steel mains and services.

In the case of cast iron, leak and failure rates due to cracking were significantly higher than with newer plastic and steel components. Assessing these risks led to a long term program to replace cast iron on a risk prioritized basis. Similarly, bare steel mains are approaching the end of their useful life due to corrosion failure. Therefore, a replacement program was also initiated

to replace EGD's bare steel mains. Both the Cast Iron and Bare Steel Main Replacement Programs are due to be completed in 2012.

Learning from these experiences and consistent with an Asset Management System approach, EGD has been working to adopt a broader risk based decision making approach to Integrity Management. This is not only consistent with a best practice industry trend, it is consistent with the evolution of regulations from a traditional "prescriptive" approach to a "goal oriented" or "risk based" approach. Annex N of CSA Z662 is an example of regulation that is evolving in this direction.

A risk based approach can be defined as a comprehensive and defensible process to identify threats, assess the potential risks from those threats, prioritize these risks and specify appropriate asset investments to mitigate likelihoods and impacts to effectively manage the risks.

The following figure is a high level representation of a risk based Integrity Management process.

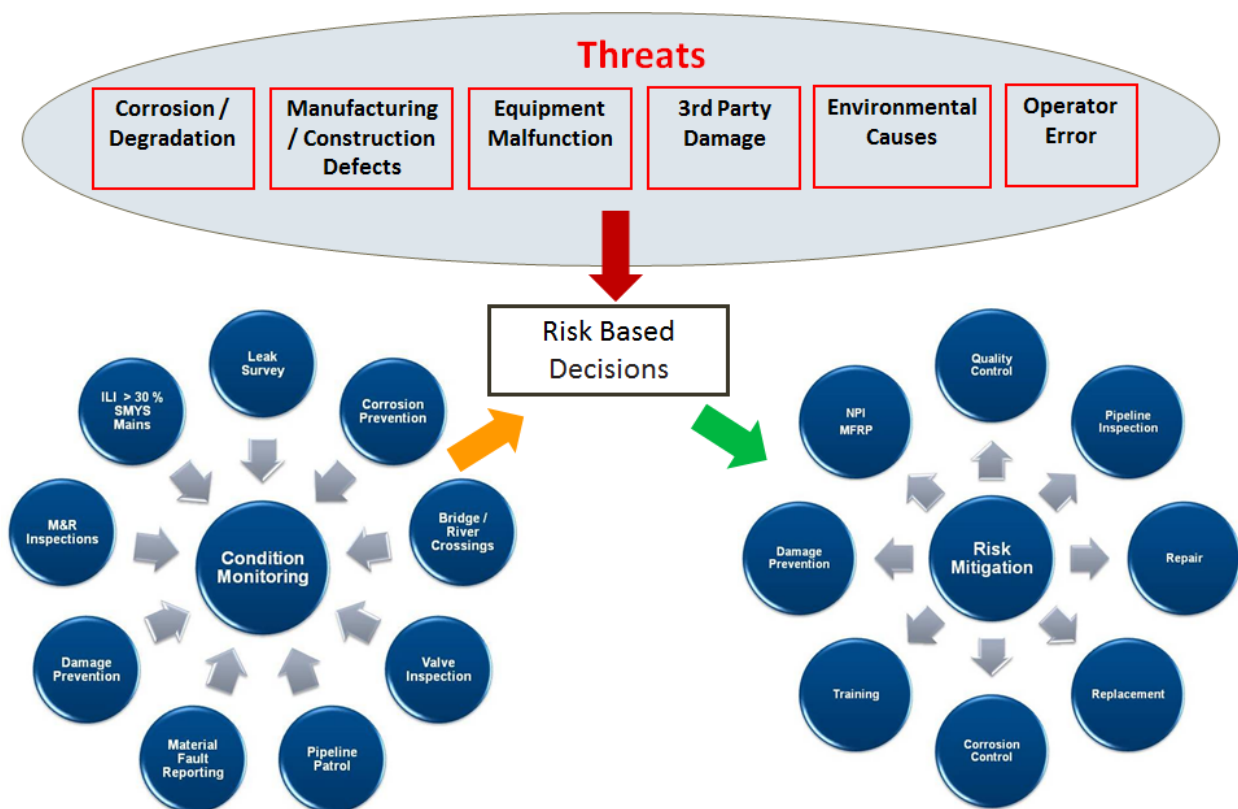


Figure 8 - Threats, Condition Monitoring and Risk Mitigation Programs

Following this risk based approach, EGD has been striving to better understand threats and related risks to the distribution system. One area of focus has been working to gain a better understanding of the condition of different classes of assets that comprise the system based on factors such as the age profile of the assets. As assets age, failure rates are anticipated to increase with the failure profile becoming more acute as the assets approach the end of their useful life. This increasing failure profile is expected to drive an increasing spend profile to maintain and ultimately replace the assets.

EGD has also been striving to improve the condition monitoring of its assets to better understand the factors that contribute to failure rates. For the past five years, since Distribution System Integrity Management Programs have been mandated through the CSA standard and the TSSA, EGD has been working to comprehensively and proactively analyze asset condition and assess which threats contribute to higher failure rates.

In the past, this form of analysis has at times been limited by the availability and completeness of the required asset information, which occurs throughout the industry. EGD continues to seek to improve its capture of asset information, which in turn continues to yield improved understanding of the condition and risks associated with the assets.

These analytical approaches are expected to play an increasing role in Integrity Management, particularly as improvements are made in gathering and correlating the required asset information. However, it is also expected that the tacit knowledge of experienced personnel will remain an important component in understanding and assessing threats and risks, prioritizing these risks and defining the mitigations needed to effectively manage these risks. Industry developments and trends will also continue to play an important role.

In summary, this evolving Integrity Management approach is intended to help ensure that EGD can continue to comply with current and future regulations and that EGD is constantly working to continue to reduce overall asset risks in a cost effective manner over time.

The development of the System Integrity and Reliability Requirements section of this Asset Plan has leveraged this Integrity Management work done to-date. It has also helped to focus these efforts and draw them together into a more formal Integrity Management process which will continue to evolve with subsequent iterations of the Asset Plan.

Theory Applied

As mentioned above, EGD has been comprehensively and proactively analyzing asset condition and failure incidents.

One trend that has been identified is the increased failure rate of a particular component, corrosion of the copper service riser immediately downstream of an AMP fitting (AMP fitting failure). A graph of the growing trend of AMP fitting failures is shown in the chart below. EGD has a Material Fault Program, under which field workers submit material failures so that the Company can physically evaluate why a component has failed through an analysis performed by EGD's Engineering Materials Evaluation Centre (EMEC). The increased trend of material faults on this asset highlighted an emerging risk. Further analysis through EGD's Work and Asset Management System identified the full scope of the issue. The red bars on the graph show the Material Fault Report submissions for AMP fitting failures. The green bars represent the failure rate as analyzed through EGD's Work and Asset Management systems.

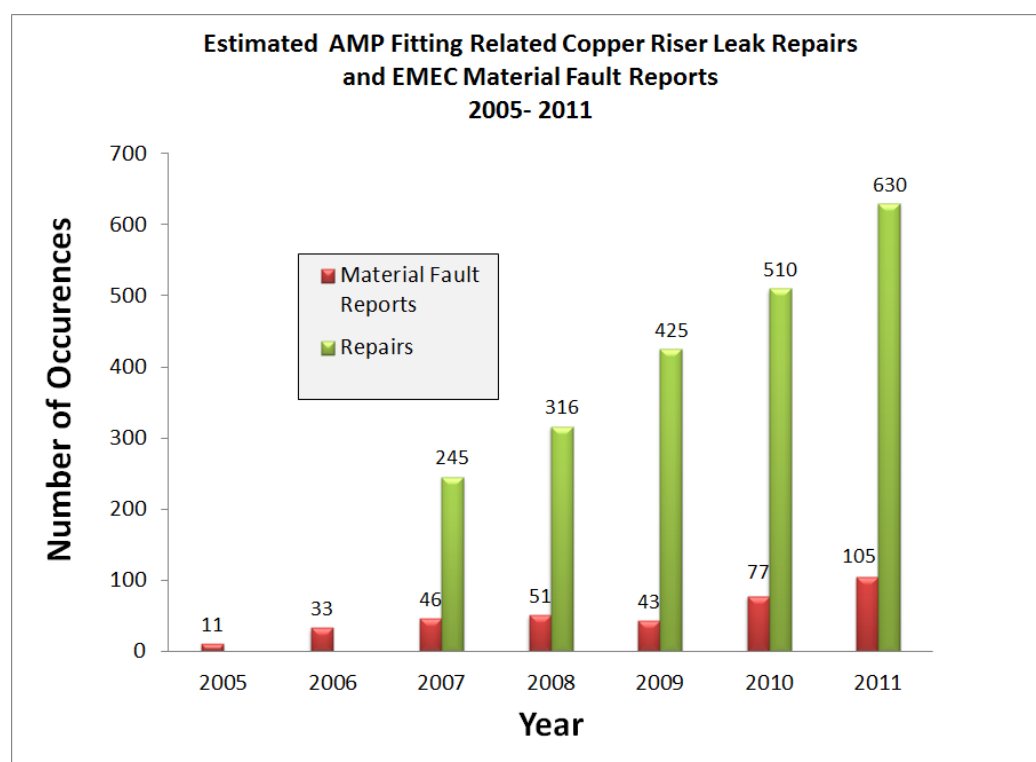


Chart 11 - Failure Analysis

Although EGD cannot predict exact future AMP fitting failure rates, the Company can predict that failures will increase over time.

Therefore, a program to mitigate failures for services that contain AMP fittings will be required going forward. This program will be designed to mitigate the risk of this failure mechanism, and

to the extent that EGD can predict which AMP fittings will fail next, a risk prioritized proactive program should be more cost effective than a reactive program.

EGD is continuing to work to understand how to predict which AMP fitting failures will occur next. In 2012, the Company plans to proactively extract physical samples in order to investigate the failure mechanisms in more detail. The outcome will provide insight into the prioritization of future replacement programs or activities.

The above failure analysis illustrates how EGD is evolving its understanding of its assets, threats to the assets, failures associated with these threats, and recommended mitigation plans.

Requirements

In applying the above Integrity Management approach, the process EGD undertook to develop the System Integrity and Reliability requirements of the Asset Plan is outlined below.

Step 1: System Integrity & Reliability asset risks were identified through three primary approaches:

- Asset condition assessment, by leveraging data gathered from EGD's operating systems and existing asset condition monitoring programs
- Tacit knowledge, gathered by engaging experienced Operations field staff to identify risks, that EGD has encountered historically
- Relevant industry developments and trends. This includes legislative and regulatory changes that are being implemented or contemplated in the United States in the wake of incidents that have occurred in the recent past as mentioned above.

The risks gathered by using these approaches were catalogued into a Risk Register.

Step 2: Risks within the Risk Register were assessed to establish a relative risk ranking.

This was accomplished by defining the risk, the current mitigation programs in place and asking a group of experienced Operational and Engineering personnel to determine the likelihood and impact of potential events based on their knowledge and experience. The following figure depicts the range of likelihood and impact that was used.

		Impact					
	Value	Minor	Moderate	Major	Severe	Worst Case	
Daily to monthly	5	P3	P2	P1	P1	P1	Likelihood
Monthly to yearly	4	P3	P2	P2	P1	P1	
Once in 1 to 10 years	3	P3	P3	P2	P2	P1	
Once in 10 to 100 years	2	P4	P3	P3	P2	P2	
Once in > 100 years	1	P4	P4	P3	P3	P3	
		1	2	3	4	5	

Figure 9 - Risk Prioritization: Likelihood & Impact Chart

The results of this qualitative risk assessment were validated with further analysis of available data.

As a result of this assessment, risks were prioritized into categories with items in the top right corner of the matrix having the greatest relative risk (Priority 1) and items in the bottom left having the least relative risk (Priority 4).

Step 3: Programs or other initiatives were defined to address each of the prioritized risks based on the Asset Management objectives, policies and strategies described in Section 4 - EGD's Asset Management Principles.

The outcome of this step was the identification of four different types of integrity initiatives to address the identified risks:

- Continuation of existing System Integrity risk mitigation programs (e.g. Cast Iron Replacement, Failure of M&R Station Components)
- Expansion of scope of existing System Integrity programs (e.g. In-Line Inspection (ILI) Scope and Technology, Damage to Non-Excess Flow Valve (EFV) Services)
- New System Integrity Programs (e.g. Corrosion Downstream of Amp Fittings)
- Studies to determine whether New System Integrity Programs are required (e.g. Field Applied Coatings on Tie-in to Steel)

The figure below provides a high-level summary of the process used to establish System Integrity and Reliability requirements.

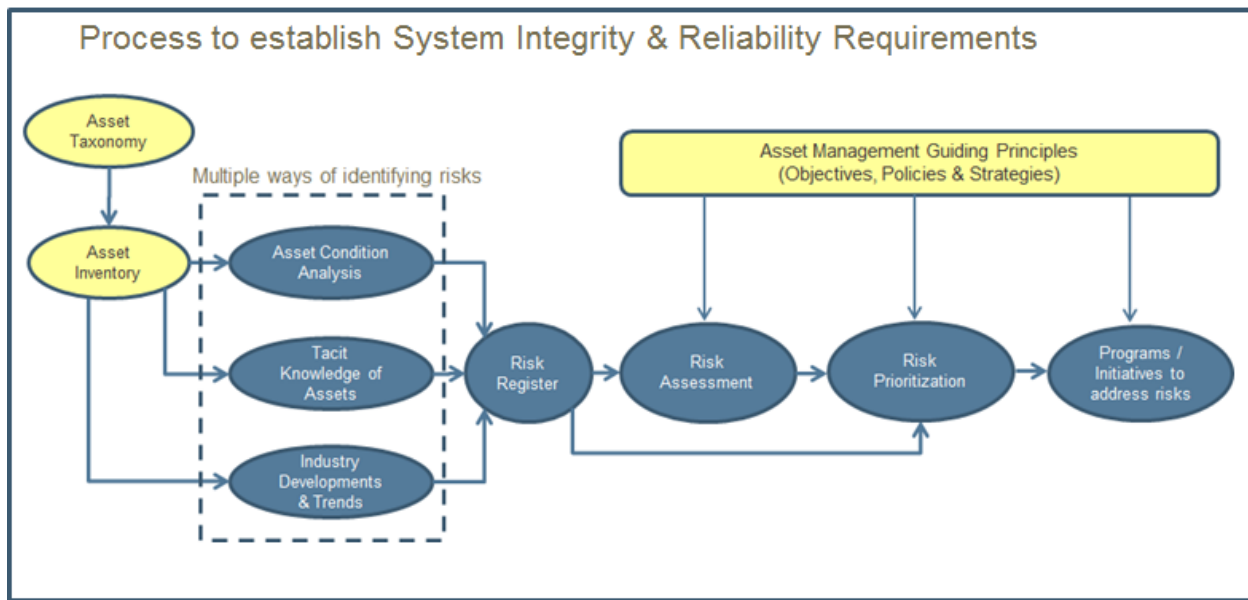


Figure 10 - Process to Establish System Integrity & Reliability Requirements

This is the first time EGD has applied the above process to support the development of a comprehensive, long range asset plan. Therefore, many of the methodologies and tools used to develop portions of the plan are first time efforts. It is expected that these methodologies and tools will be continuously improved over time with resultant improvements in future iterations of the Asset Plan.

Step 1: The Risk Register

The following table was developed through Step 1 of the process described above.

ASSET CLASS	RISK	RISK DESCRIPTION
Mains	Cast Iron	Cast iron mains have good corrosion resistance but the material can degrade due to graphitization. Leaks occur at main breaks or may occur at bell joints with the primary threat being ground movement by natural forces or excavation.
	Bare Steel	Bare steel mains may leak due to corrosion and cannot be effectively protected from corrosion in the same manner as coated steel.
	ILI Scope & Technology	The scope of current inspection programs consists of pipelines with operating pressures at or greater than 30% Specified Minimum Yield Strength (SMYS). Defects that are beyond the current scope and identification technology may not get identified.
	Older Coated Steel	Corrosion may occur where the coating is damaged.
	Field Applied Coatings on Tie-In to Steel	For certain field applied coatings on tie-in to steel, the coating may be disbonding from the steel pipe, leaving the area prone to corrosion.
	Plastic Mains (including Services)	Brittle like cracking has been identified by the industry in certain vintage plastic pipes. As a result, leaks may occur at stress points.
	Corrosion of Carrier Pipe in Casings	In situations where the steel carrier pipe touches the casing, cathodic protection may be compromised, possibly accelerating corrosion of the carrier pipe resulting in loss of containment.
	Reliability of Supply	Failure risk within supply chain. Potential for significant customer outages under certain upstream and downstream upset conditions.
	Don River Bridge Crossing	Extra High Pressure 30-inch line on bridge may be damaged in a flood resulting in significant customer outages.
Services	Corrosion of segment of the 20-inch Lakeshore line	There is a 650m segment of the line that has known coating disbondment leading to a risk of corrosion.
	Corrosion on Copper Services	Copper services were installed between the mid 1960's and early 1970's. Due to their age, these services are subject to the risk of leaks due to internal and external corrosion.
	Corrosion of Steel Tubing	Steel tubing is thin wall and can fail due to corrosion more quickly than steel pipe. It has a greater likelihood of release of gas than thicker wall steel pipe.
	Corrosion on Bare Steel Services	Bare steel services may leak due to corrosion and cannot be effectively protected from corrosion in the same manner as coated steel.
	Corrosion on Isolated Steel	Isolated steel pipe may not be cathodically protected from corrosion and therefore may be subject to accelerated corrosion.
M&R Equipment	Damage to Non-EFV Services	Significant volume of gas may be released when a service is damaged and the service does not have an Excess Flow Valve (EFV).
	Failure of Gate Station Components	Failure of gate station components can lead to overpressure and/or loss of containment of high pressure gas or odourant.
	Failure of District Station Components	Failure of district station components can lead to overpressure and/or loss of containment of gas.
	Failure of LP Station Components	Failure of Low Pressure (LP) station components can lead to overpressure and/or loss of containment of gas.
M&R Equipment	Failure of Farm Tap Components	Failure of farm tap components can lead to overpressure and/or loss of containment of gas.

ASSET CLASS	RISK	RISK DESCRIPTION
Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	Valve malfunction due to corrosion of bolts and material brittleness may result in loss of containment of gas.
	Failure of WingLock Valves	Incorrect application of force to operate such valves can cause the internal components of the valve to break which may result in loss of containment of gas.
	Isolation Valves	Due to limited number and/or the technology associated with isolation valves, the company may be constrained when addressing an emergency related to line failure.
	Main Line Valves	Main line valves may be difficult to access or may not operate as required which may result in delay in response to an emergency.
	Load Shed Zones	Due to a limited number and/or the technology associated with isolation valves, the company may be constrained when addressing an emergency related to gas supply disruptions.
Fittings	Corrosion downstream of AMP Fittings	Potential for an underground gas leak to occur downstream of the AMP fitting due to corrosion of the copper risers connected to plastic services.
	Mainline Compression Couplings	Unrestrained compression couplings, when exposed at a point of thrust, can lead to loss of containment.
	Anodeless Risers	Anodeless risers were purchased to avoid the need for cathodic protection. Corrosion may be occurring where the epoxy coating may have been chipped. Exposed plastic pipe can then degrade in sunlight.
	Chicago Fittings	Potential for an above ground gas leak to occur at the Chicago fitting due to age and/or ground movement.
	Compression Outlet Service Tees	Compression outlet on a steel service connection may pull apart due to third party damage or ground movement resulting in loss of containment of gas.
	Jumpers & Service Extensions	Steel jumpers and service extensions are used to connect regulators located outside of a building to piping or meters located inside a building. The jumper or service extension may corrode if the coating is damaged leading to a loss of containment of gas.
	Punch Tee Cap	Punch Tee Cap, including vintage plastic material variety are susceptible to cracking when over-torqued during installation which may result in leaks.
	Expansion Joints	Failure of aging expansion joints, resulting in leaks.
General	Records Integrity	Inaccurate or incomplete records may impact operational decisions and safety.
	Cross Bores	Homeowner/Plumber/City, while attempting to clear a sewer may damage a gas line that at time of installation was inadvertently installed through a sewer lateral, resulting in loss of containment of gas.
	Meter Barriers	A lack of meter barriers in areas where meters may be susceptible to damage from vehicles may result in damage to the meter set, resulting in loss of containment of gas.
	Residential Meter Sets	Changes to requirements around meter exchange government inspections (MXGIs).
	Inside Regulators	Third party damage to a service line may result in an unregulated gas escape inside a customer premise.
	Encased Bridge Crossings	Leaks or pipe support deterioration could develop where visual inspection isn't possible.

Table 5 - Risk Register

Step 2: Relative Risk Ranking

The result of the risk assessment and prioritization from Step 2 is summarized in the table below:

	Priority 1	Priority 2	Priority 3
Mains	Cast Iron	Older Coated Steel	
	Field Applied Coating on Tie-In to Steel	Corrosion of Carrier Pipe in Casings	
	Corrosion of segment of the 20-inch Lakeshore Line	Inline Inspection Scope and Technology	
	Don River Bridge Crossing	Plastic Mains	
		Bare Steel	
Services		Corrosion on Copper Services	
		Corrosion of Steel Tubing	
		Corrosion on Bare Steel Services	
		Corrosion on Isolated Steel	
		Damage to Non-EFV Services	
M&R Equipment	Failure of Gate Station Components	Failure of Farm Tap Components	
	Failure of District Station Components		
	Failure of LP Station Components		
Valves	Isolation Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	
	Main Line Valves	Failure of WingLock Valves	
	Load Shed Zones		
Fittings	Corrosion downstream of AMP Fittings	Anodeless Risers	Expansion Joints
	Mainline Compression Couplings	Chicago Fittings	
	Compression Outlet Service Tees	Jumpers & Service Extensions	
		Punch Tee Cap	
General	Records Integrity	Inside Regulators	
	Cross Bores	Encased Bridge Crossings	
	Meter Barriers	Residential Meter Sets	

Table 6 - Risk Prioritization

Assets assessed as Priority 4 risks are considered to simply require monitoring to ensure that their risk level is not increasing.

Step 3: Programs Defined to Address Risks

As an outcome of Step 3, the following table shows the initiatives that have been established to address the risks contained in the risk register.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
Mains	Cast Iron	Cast Iron Replacement Program	Complete the replacement and abandonment of all cast iron mains by 2012. Some restoration may be required in 2013.
	Bare Steel	Bare Steel Replacement Program	Complete replacement and abandonment of all bare steel mains by 2012.
	ILI Scope & Technology	ILI for pipelines over 20% SMYS	Continue the existing inline inspection (ILI) program, expand the scope to include targeted lines over 20% SMYS and include new technology ILI tools in future ILI runs.
	Older Coated Steel	Coated Steel Program (Mains & Services)	Study to evaluate the effectiveness of different manufacturer applied coatings to protect from corrosion over time in order to determine where upgrades or additional corrosion protection may be required.
	Field Applied Coatings on Tie-In to Steel	Field Applied Coatings Study	Study to understand issues with field applied coatings on tie-in to steel, and how to resolve it.
	Plastic Mains (including Services)	Plastic Mains (incl Services) Study	Study to understand plastic pipe susceptibility to cracking. Study to be done in conjunction with the Gas Technology Institute (GTI).
	Corrosion of Carrier Pipe in Casings	Casing Study & Program	Study to enhance knowledge of the effectiveness of cathodic protection of the carrier pipe in casing locations.
	Reliability of Supply	Reinforcement Projects	Projects to construct Reinforcement Mains in networks to address capacity or reliability issues.
	Don River Bridge Crossing	Don River Bridge Crossing Replacement	Determine the purpose, need and timing of a replacement solution and implement the solution.
Services	Corrosion of segment of the 20-inch Lakeshore line	20-Inch Lakeshore Line Replacement	Determine the purpose, need and timing of a replacement solution and implement the solution.
	Corrosion on Copper Services	Copper Services Replacement	Complete the current replacement program for copper services.
	Corrosion of Steel Tubing	Steel Tubing Service Replacement	Complete the current replacement program for steel tubing services.
	Corrosion on Bare Steel Services	Bare Steel Services Study	Identify locations of bare steel services not being replaced with the cast iron program in order to develop a proactive replacement program.
	Corrosion on Isolated Steel	Isolated Steel Study	Study to increase knowledge of where isolated steel pipe may occur to enhance corrosion prevention strategies.
	Damage to Non-EFV Services	EFV Program	Study and related pilot to determine how to install EFVs on pre-2006 services. Expand installation of EFVs to additional customers such as multi-family and small commercial customers.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
M&R Equipment	Failure of Gate Station Components	Gate Station Equipment Replacement	Continue with existing gate station maintenance & replacement programs.
	Failure of District Station Components	District Station Equipment Replacement	Continue with existing district station maintenance & replacement programs.
	Failure of LP Station Components	Low Pressure Delivery Meter Set Program	Study to enhance the knowledge of LP station condition and prioritize related upgrades, followed by required upgrade/replacement programs.
	Failure of Farm Tap Components	Farm Tap Study	Study to determine condition of farm taps and to define program requirements if necessary.
Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	Failure of Bonnet Bolts on Valves Study	Study to determine condition of Bonnet Bolts on Valves and to define program requirements if necessary.
	Failure of WingLock Valves	WingLock Valve Study & Replacement	Study to determine the condition of WingLock valves and to define program requirements if necessary.
	Isolation Valves	Isolation Valve Study & Installation (RCV / ASV)	Study to validate the adequacy of Enbridge Gas Distribution's current main line valve design requirements and any new/retrofit installations required associated with a change in the design requirement (including automatic shutoff and remote (ASV) control valves (RCV)).
	Main Line Valves		
	Load Shed Zones		
Fittings	Corrosion downstream of AMP Fittings	AMP Fitting Replacement	Study to examine leak rate trends and develop a replacement plan, followed by execution of the replacement plan.
	Mainline Compression Couplings	Targeted Compression Couplings Pressure Containment Sleeve Program	Study to identify targeted compression couplings and to install pressure containment sleeves over these couplings.
	Anodeless Risers	Anodeless Riser Replacement	Study to better understand the nature and extent of corrosion issues associated with anodeless risers, followed by a repair/replacement program as appropriate.
	Chicago Fittings	Chicago Fitting Study	Study to determine if a proactive replacement program would be more effective than reactive repair.
	Compression Outlet Service Tees	Compression Outlet Service Tee Study	Study to identify the most effective risk mitigation and define program requirements if necessary.
	Jumpers & Service Extensions	Jumper and Service Extension Study	Study to increase knowledge regarding steel jumper and service extension condition and determine program requirements if necessary, followed by program execution. This study will be done in conjunction with the Isolated Steel study.
	Punch Tee Cap	Punch Tee Cap Program	Continue to monitor and repair as required leveraging the material fault report program and Construction and Maintenance manual.
	Expansion Joints	Expansion Joint Study	Study to determine the condition of expansion joints.

ASSET CLASS	RISK	INITIATIVE NAME	INITIATIVE DESCRIPTION
General	Records Integrity	Distribution Records Management Program	Set of projects to identify and resolve various records related issues, including clean-up of data, refinement of processes and technology changes.
		Verification of MAOP	Required to mitigate records risks via MAOP verification and resulting in-line inspections requirements.
	Cross Bores	Sewer Safety Program	Inspection and other programs to proactively identify sewer lateral risks, ensure construction practices do not create new risks, increase public awareness, and resolve instances where identified.
	Meter Barriers	Meter Barrier Study & Program	Study followed by program to install meter barriers where field conditions have changed resulting in a meter barrier being required.
	Residential Meter Sets	Residential Meter Sets Study (incl. SMART system)	Study to evaluate the application of new technologies for improved management of residential meters while addressing revised requirements for meter exchanges
	Inside Regulators	Inside Regulator Replacement	Create exterior weak link on inside regulators so that break occurs outside if external force applied to the meter set. Move inside meters outside where possible.
	Encased Bridge Crossings	Encased Bridge Crossings Study	Study to evaluate the condition of bridge crossings.

Table 7 - System Integrity & Reliability Risk Mitigation Initiatives

Implementation Plan & Estimated Capital Investments

Based on the relative risk ranking, project interdependencies and current work in progress, an implementation schedule was established for the various initiatives that are required to meet the System Integrity & Reliability requirements. The relative risk ranking identified initiatives with varying priorities from 1 to 3 which consists of continuing existing programs, expanding the scope of other existing programs, initiating new programs and conducting studies.

Risks were prioritized based on current asset condition and tacit and industry knowledge information. As more knowledge is gained through studies, certain prioritization may change. Priority 1 initiatives address high impact assets. Priority 2 and 3 initiatives include risk mitigation programs for assets whose combination of likelihood of an event and degree of impact are lower.

Consistent with the risk based approach, Priority 1 and select priority 2 initiatives are identified early in the schedule. Select Priority 2 and Priority 3 initiatives are scheduled later. Within each risk mitigation program, a second level of prioritization is applied to address higher risk assets early in each program.

Some risks identified by the process are currently not well understood. These risks require studies to further analyze and understand risk dynamics and potential mitigation strategies. In the plan, where a risk study is followed by a program, EGD has a high confidence, based on failure data and tacit knowledge, that a risk mitigation program will be required, even though the form of the program may not be fully understood. Where a risk study does not have a program illustrated beyond the study, the level of certainty that a risk mitigation program will be required is lower. The study itself may allow EGD to reduce the assessment of the risk to a lower priority.

To the extent possible, EGD has attempted to smooth the spending on the overall system integrity and reliability programs. For example, many of the programs have been defined as multi-year, long term initiatives. However, it should be noted that, due to aging infrastructure and other factors such as increased Company or industry knowledge, EGD's belief is that asset investments will require increased spending over time. It should also be noted that improved understanding of certain risks may require a higher rate of spend to stay ahead of the failure curve, and reduce risk in a more timely manner.

The figure below summarizes the implementation plan for the initiatives, and provides an estimate for the required capital investments over the 2012 to 2021 period.

ASSET CLASS	RISK	INITIATIVE NAME	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) (\$000)
Mains	Cast Iron	Cast Iron Replacement Program	Prog										\$26,132
	Bare Steel	Bare Steel Replacement Program	Prog										\$900
	ILI Scope & Technology	ILI for pipelines over 20% SMYS	Program										\$82,600
	Older Coated Steel	Coated Steel Program (Mains & Services)			Study								\$720
	Field Applied Coatings on Tie-In to Steel	Field Applied Coatings Study	Study										\$720
	Plastic Mains (including Services)	Plastic Mains (incl Services) Study	Study										\$40
	Corrosion of Carrier Pipe in Casings	Casing Study & Program	Study		Program								\$4,200
	Reliability of Supply	Reinforcement Projects											Covered as part of Reinforcements
	Don River Bridge Crossing	Don River Bridge Crossing Replacement		Prog									\$3,500
	Corrosion of segment of the 20-inch Lakeshore line	20-Inch Lakeshore Line Replacement	Prog										\$2,000
Services	Corrosion on Copper Services	Copper Services Replacement	Program										\$15,000
	Corrosion of Steel Tubing	Steel Tubing Service Replacement	Program										\$2,000
	Corrosion on Bare Steel Services	Bare Steel Services Study				Study							\$200
	Corrosion on Isolated Steel	Isolated Steel Study	Study										\$200
	Damage to Non-EFV Services	EFV Program		Study									\$1,500
M&R Equipment	Failure of Gate Station Components	Gate Station Equipment Replacement	Program										\$50,424
	Failure of District Station Components	District Station Equipment Replacement	Program										\$25,013
	Failure of LP Station Components	Low Pressure Delivery Meter Set Program	Program										\$95,380
	Failure of Farm Tap Components	Farm Tap Study				Study							\$200

ASSET CLASS	RISK	INITIATIVE NAME	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Forecast (2012-2021) (\$000)
Valves	Failure of Bonnet Bolts on Valves (1.25" to 2")	Failure of Bonnet Bolts on Valves Study					Study						\$200
	Failure of WingLock Valves	WingLock Valve Study & Replacement		Study				Program					\$26,300
	Isolation Valves	Isolation Valve Study & Installation (RCV / ASV)											
	Main Line Valves		Study					Program					\$27,480
	Load Shed Zones												
Fittings	Corrosion downstream of AMP Fittings	AMP Fitting Replacement	Study					Program					\$221,200
	Mainline Compression Couplings	Targeted Compression Couplings Pressure Containment Sleeve Program	Study					Program					\$18,200
	Anodeless Risers	Anodeless Riser Replacement			Study			Program					\$4,320
	Chicago Fittings	Chicago Fitting Study		Study									\$200
	Compression Outlet Service Tees	Compression Outlet Service Tee Study	Study										\$400
	Jumpers & Service Extensions	Jumper and Service Extension Study	Study		Program								\$500
	Punch Tee Cap	Punch Tee Cap Program						Program					Covered through O&M (maintenance cost)
	Expansion Joints	Expansion Joint Study							Study				\$200
General	Records Integrity	Distribution Records Management Program						Program					\$59,023
		Verification of MAOP		Program									\$18,300
	Cross Bores	Sewer Safety Program						Program					\$8,976
	Meter Barriers	Meter Barrier Study & Program						Program					Included as part of Customer Growth related M&R
	Residential Meter Sets	Residential Meter Sets Study (incl. SMART system)			Study								\$200
	Inside Regulators	Inside Regulator Replacement	Prog										\$380
	Encased Bridge Crossings	Encased Bridge Crossings Study				Study							\$200

Figure 11 - System Integrity & Reliability: Implementation Schedule & Cost

The following chart depicts EGD's historic and forecast capital spend for System Integrity & Reliability.

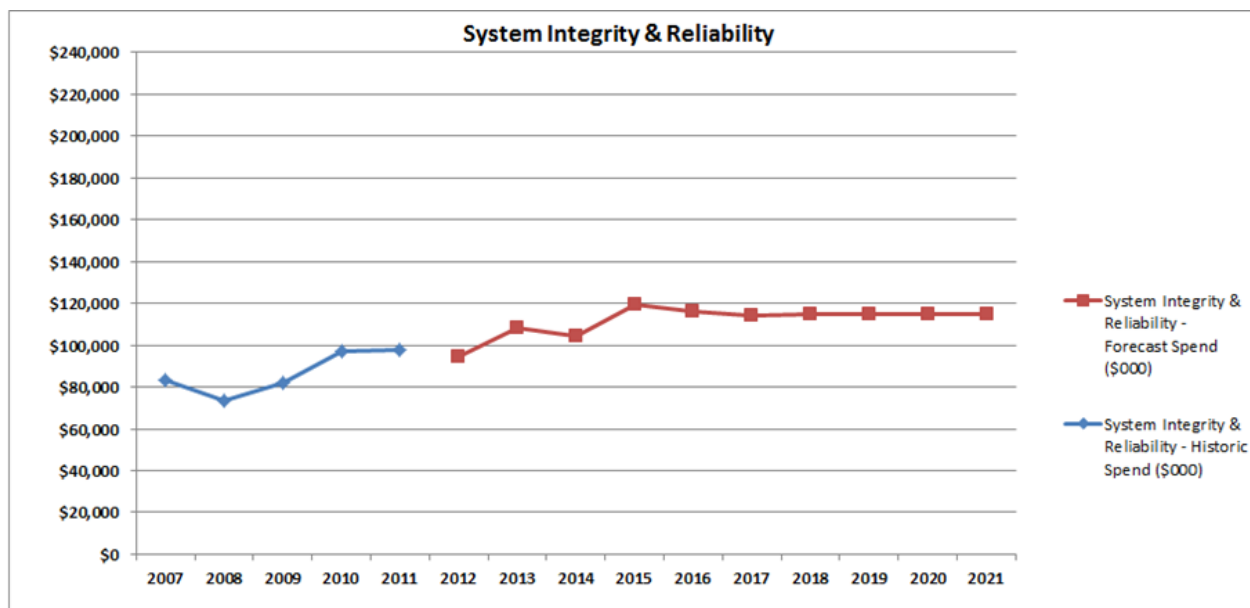


Chart 12 - System Integrity & Reliability: Historic & Forecast Capital Spend

The forecast spend for System Integrity and Reliability trends up between 2012 and 2015 and then stays relatively flat until 2021.

There are several reasons that contribute to the upward trend in the capital spend from 2012 to 2015 :

- Beyond the existing programs to replace Cast Iron and Bare Steel, the risk assessment has identified the need to address additional classes of assets that are near the end of their useful life. Examples include Copper Services, Steel Tubing Services, AMP Fittings, and Mainline Compression Couplings
- Studies will need to be conducted to improve our understanding of the condition of specific classes of assets where risks have been identified. These studies will help establish the requirements and scope of any related mitigation programs
- Records Integrity, including completeness, accuracy, verifiability, timeliness, and accessibility, was assessed as one of the key risks. EGD has identified a number of initiatives, with significant upfront investments in 2013 and continuing investments in 2014 to 2021 to address this risk. For example, the Company is embarking on utilizing

Geospatial Positioning System (GPS) technology to more accurately identify the location of EGD's distribution assets

- Consistent with industry best-practices, EGD will expand its current in-line inspection program to include targetted XHP pipelines operating over 20% Specified Minimum Yield Strength (SMYS)
- EGD will enhance its capability to effectively isolate portions of the system to minimize the impact of planned or unplanned service disruptions by installing additional mainline valves at key locations

Many of the programs that are needed to mitigate System Integrity & Reliability risks span multiple years. An effort was made to smooth these expenses over the term of the Asset Plan.

5.5 Relocations

Requirements

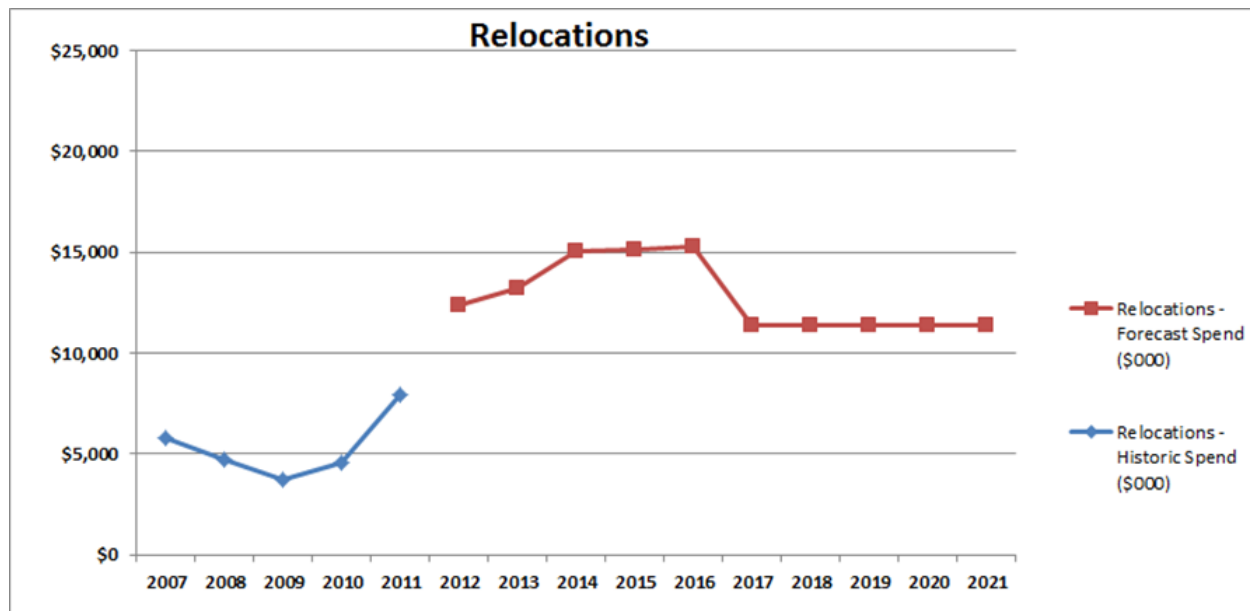
Relocation requirements are generally driven by municipal and other third party works. While some of these relocation requirements are known for the next few years, it is not possible to comprehensively forecast the future relocation requirements over the term of the Asset Plan. Hence, known future projects have to be combined with historic and projected trends to estimate the capital investments needed to support relocation requirements.

Relocation requirements primarily arise from road realignments and expansions, bridge rehabilitation, grade separations or other developments that are initiated by a city, municipality or other third party. In most cases, EGD is able to recover a portion of the relocation costs from the municipality or other party requiring the relocation.

While forecasting relocation requirements and costs, EGD takes into account the normal activity level of relocations and their associated costs. Projects or programs identified as incremental to that normal activity level are then added. Incremental activity could include items such as Infrastructure Stimulus Fund activities, major transit projects (subway expansion, GTAA Rail Link, Rapid Transit – Eglinton LRT, York Region Rapid Transit, Ottawa LRT), major road expansions (407 Extension) and preparation for the 2016 Pan Am Games.

Implementation Plan & Estimated Capital Investments

The following chart depicts the historic and forecast capital investments, net of the re-billable portion, required for relocations.



2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
\$5,770	\$4,717	\$3,749	\$4,551	\$7,965	\$12,350	\$13,209	\$15,035	\$15,150	\$15,259	\$11,400	\$11,400	\$11,400	\$11,400	\$11,400

Chart 13 - Relocations: Historic & Forecast Capital Spend

The capital spend profile shows an escalation of relocation expenditure over the period of this Asset Plan. In addition to known relocation projects in this time period, EGD expects additional relocations driven by preparations for the Pan Am games, and light rail transit and subway projects that have been planned and already under way in the GTA and Ottawa.

6. Financial Summary

The table below summarizes the forecasted capital spend profile to meet the four types of asset related requirements within the scope of the Asset Plan.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Customer Additions (\$000)	\$76,982	\$84,413	\$84,036	\$86,264	\$87,974	\$89,003	\$89,485	\$90,021	\$90,622	\$90,887
Relocations (\$000)	\$12,350	\$13,209	\$15,035	\$15,150	\$15,259	\$11,400	\$11,400	\$11,400	\$11,400	\$11,400
Routine Reinforcements (\$000)	\$24,756	\$11,550	\$32,400	\$4,939	\$6,650	\$26,300	\$29,500	\$30,417	\$6,750	\$1,500
System Integrity & Reliability (\$000)	\$94,583	\$108,041	\$104,143	\$119,271	\$116,324	\$114,427	\$114,779	\$114,579	\$114,573	\$114,554
Total (Excluding Major Reinforcements)	\$208,671	\$217,213	\$235,614	\$225,624	\$226,207	\$241,130	\$245,164	\$246,417	\$223,345	\$218,341
Major Reinforcements (\$000)	\$13,127	\$51,117	\$296,746	\$231,900	\$0	\$0	\$0	\$0	\$0	\$0
Total (Including Major Reinforcements)	\$221,798	\$268,330	\$532,360	\$457,524	\$226,207	\$241,130	\$245,164	\$246,417	\$223,345	\$218,341

Chart 14 - Financial Summary of Asset Spend by Category of Requirements

The following is a general set of assumptions that was used in developing these forecasts:

- For the term 2014-2021, the estimated capital spend is based on 2012 dollars, i.e. inflation and other time-based adjustments have not been applied
- Estimates are based on EGD's asset requirements as of December 2011. Going forward, as part of the annual Asset Planning cycle, these requirements will be reviewed and revised as needed. The capital investment profile is expected to change as the requirements evolve
- Estimates include only the direct capital costs of the projects and initiatives set out in the Asset Plan
- At this time, only a range of estimates is available for the GTA project. The mid-point of this range has been assumed for the purpose of the Asset Plan

The charts below depict the overall spend for the term of the Asset Plan excluding and including major reinforcements.

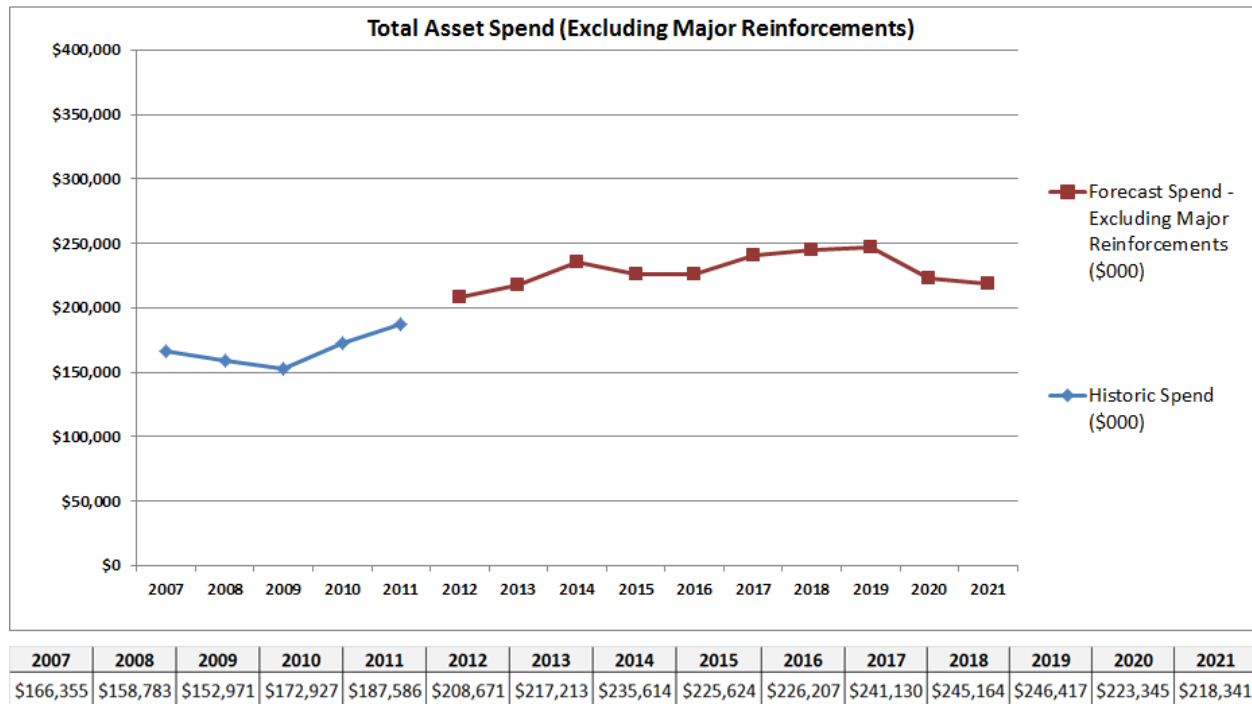


Chart 15 - Financial Summary of Total Asset Capital Spend (Excluding Major Reinforcements)

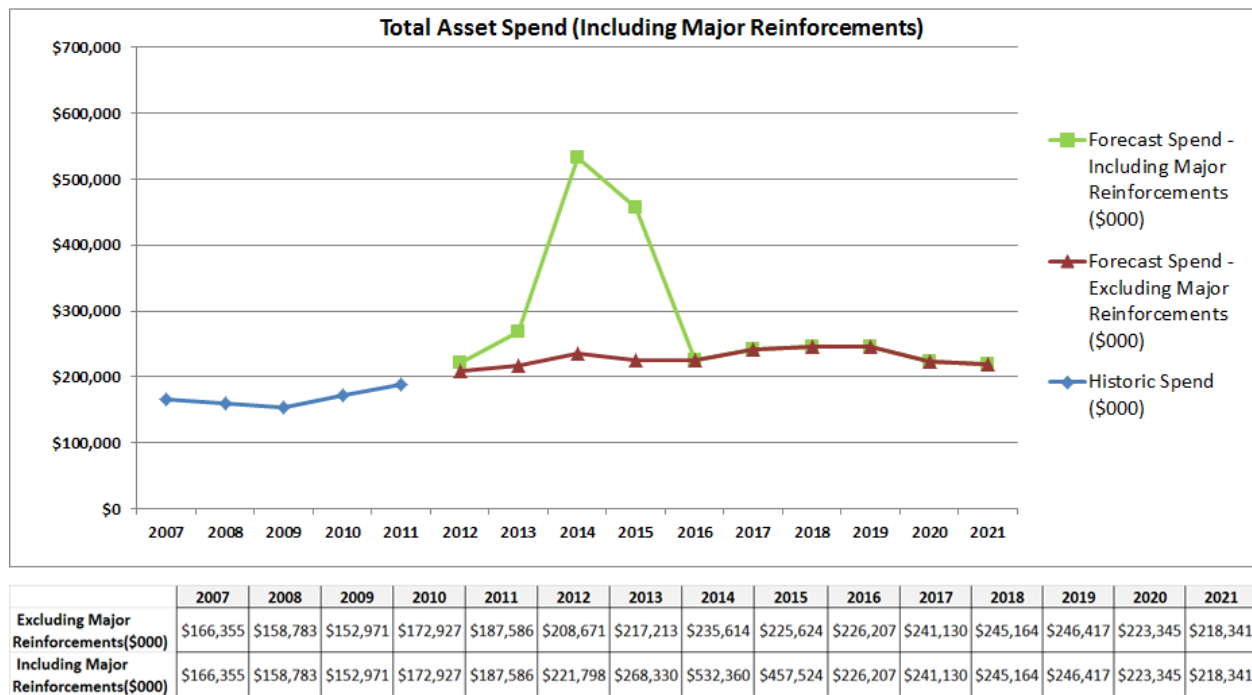


Chart 16 - Financial Summary of Total Asset Capital Spend (Including Major Reinforcements)

SEC INTERROGATORY #136

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 9] With respect to the spreadsheet attached, and headed up "Capital Spending Actuals and Forecasts from Asset Plan":

- a. Please confirm that line 1 correctly sets out the total direct capital excluding major reinforcements, from Chart 1.
- b. Please confirm that lines 2 and 3 correctly calculate the one year dollar and percentage increases in direct capital.
- c. Please confirm that line 4 correctly calculates the three year rolling average percentage increase in direct capital.
- d. Please confirm that line 5 correctly calculates the percentage increase in direct capital from the sixth previous year.
- e. Please confirm that line 6 correctly sets out the total direct capital excluding major reinforcements from the 2012 Asset Plan.
- f. Please confirm that lines 7 and 8 correctly calculate the dollar and percentage increases in annual direct capital from the 2012 Asset Plan to the 2013 Asset Plan.
- g. Please extend lines 1 through five of the table back to 2000.
- h. Please extend the two charts to include the extension of data included in (g) above.

RESPONSE

- a) The figures in Chart 1 of pre-filed evidence Exhibit B2, Tab 10, Schedule 1, for the line item labeled Total Excluding Major Reinforcements is correctly represented in Line 1 of the attached spreadsheet, headed "Capital Spending Actuals and Forecasts from Asset Plan".

Witness: L. Lawler

- b) Lines 2 and 3 of the spreadsheet attached are correctly calculating the year over year dollar and percentage variance in direct capital.
- c) Line 4 of the spreadsheet attached correctly calculates the 3 year rolling average of the year over year percentage variance in direct capital.
- d) Line 5 of the spreadsheet attached correctly calculates the percent increase in direct capital from the six previous years.
- e) Line 6 of the spreadsheet attached correctly represents the total direct capital excluding major reinforcements from the 2012 Asset Plan.
- f) Lines 7 and 8 of the spreadsheet attached are correctly calculating the dollar and percentage variance in direct capital from 2012 Asset Plan to the 2013 Asset Plan.
- g) Refer to attached file.
- h) Refer to attached file.

Witness: L. Lawler

Capital Spending Actuals and Forecasts from Asset Plan

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1 Actual/Forecast	\$ 126.2	\$ 162.4	\$ 170.6	\$ 137.1	\$ 143.0	\$ 164.2	\$ 193.9	\$ 166.4	\$ 158.8	\$ 153.0	\$ 172.9	\$ 187.6	\$ 221.3	\$ 219.8	\$ 242.8	\$ 293.1	\$ 294.2	\$ 317.4	\$ 344.3	\$ 353.4	\$ 308.1	\$ 312.3	\$ 339.2
2 Increase	\$126.2	\$36.2	\$8.2	-\$33.5	\$5.9	\$21.2	\$29.7	-\$27.5	-\$7.6	-\$5.8	\$20.0	\$14.7	\$33.7	-\$1.5	\$23.0	\$50.3	\$1.2	\$23.2	\$26.9	\$9.1	-\$45.3	\$4.2	\$26.8
3 Percentage		28.71%	5.03%	-19.62%	4.32%	14.79%	18.08%	-14.21%	-4.55%	-3.66%	13.05%	8.48%	17.99%	-0.69%	10.47%	20.71%	0.39%	7.88%	8.47%	2.64%	-12.83%	1.37%	8.60%
4 Three Year Rolling				4.71%	-3.42%	-0.17%	12.40%	6.22%	-0.22%	-7.47%	1.61%	5.95%	13.17%	8.59%	9.25%	10.16%	10.52%	9.66%	5.58%	6.33%	-0.57%	-2.94%	-0.95%
5 Six Year Increase							53.67%	2.43%	-6.92%	11.56%	20.89%	14.24%	14.15%	32.12%	52.92%	91.59%	70.15%	69.22%	55.57%	60.80%	26.89%	6.56%	15.27%
6 2012 Asset Plan	\$ 126.2	\$ 162.4	\$ 170.6	\$ 137.1	\$ 143.0	\$ 164.2	\$ 193.9	\$ 166.4	\$ 158.8	\$ 153.0	\$ 172.9	\$ 187.6	\$ 208.7	\$ 217.2	\$ 235.6	\$ 225.6	\$ 226.2	\$ 241.1	\$ 245.2	\$ 246.4	\$ 223.3	\$ 218.3	\$ 2079.1
7 Increase from 2012	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$12.7	\$2.6	\$7.2	\$67.5	\$68.0	\$76.3	\$99.2	\$107.0	\$84.8	\$94.0	\$606.5
8 Percentage Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.07%	1.19%	3.05%	29.90%	30.07%	31.64%	40.45%	43.43%	37.95%	43.04%	29.17%

SEC INTERROGATORY #137

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 9] Please restate Chart 1 including overheads.

RESPONSE

The purpose of the Asset Plan is to identify the work required to be performed on the assets associated with maintaining System Integrity and Reliability. Since it is not a budget document, it informs the budget regarding the direct costs associated with this work. The overheads associated with capital expenditures are a function of the annual capital program and are incorporated into the overall Capital Budget.

Witness: L. Lawler

SEC INTERROGATORY #138

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 1] Please provide the Applicant's plan, road map, or other internal document that formed the basis of the initiative of "adopting an Asset Management System approach".

RESPONSE

In the initial stages of developing its Asset Management System, EGD engaged a consulting firm (The Woodhouse Partnership) to assess its current Asset Management practices relative to the PAS 55 Standard and develop a roadmap for enhancing those practices through the implementation of an Asset Management System. The consulting firm also provided assistance in developing some of the components of the system. Over time, EGD developed its own expertise in Asset Management and continued the development of its Asset Management System without further assistance from the consulting firm.

See the attached report entitled "Asset Management Roadmap".

ENBRIDGE GAS DISTRIBUTION

ASSET MANAGEMENT ROADMAP

(WORKING DOCUMENTS & EXPLANATION)



— The —
Woodhouse Partnership
— Limited —

26th September 2005
DRAFT version 1.1

Enbridge Gas Distribution – the way forward

1 Introduction

This is a high-level discussion of Asset Management 'Roadmap' for EGD which is described in the simplified Gantt chart (figure 1) which shows the recommended programme of desirable activities and their interdependencies. It is intended to be read in conjunction with the Interactive Assessment Report and the spreadsheet of detailed issues identified, goals and objectives, and component actions which were identified in an interactive workshop with EGD staff.

It must be stated clearly at the outset that, in contrast with many traditional consultancy assignments, that generate a report and 'recommendations', the Roadmap and following activity descriptions comprise mostly a coordination of EGD's own recognised requirements and desires to move forward. Our role, as both discussion catalysts and AM experts, has been to distil, collate and complement the ideas and opportunities put forward by EGD personnel, so that the 'Roadmap' is not a consultancy proposal but a working document/framework for discussing and refining priorities towards a clearer and more aligned management of EGD's assets.

The second 'caveat' we must mention is the clear sensitivity on the subject of cost/benefits. Whatever we suggest in terms of opportunity value, or efforts required, is going to be tempered by the recent experiences and variety of opinions surrounding the EnVision project. We have therefore restricted ourselves to very conservative estimation of the achievable *incremental* benefits to be obtained by the various activities proposed and the *combined impact* of the necessary components. It is vital to recognise that this is not a 'pick-and-mix' menu of possible activities – the whole point of a more integrated approach to life cycle asset care & asset exploitation is that the jigsaw components are addressed in combination. Tackling the capital investment planning process, for example, without adequate attention to the education/motivation/communication 'enablers' would risk being yet another 'temporary enthusiasm'. Indeed, any item that is deemed *not* necessary or worthwhile in the Roadmap should be reviewed for its secondary impact on cost-effectiveness and sustainability of the total picture (i.e. we don't want to design and build a Ferrari, then leave off one wheel just to save money!).

Furthermore it should be recognised that asset management 'best practice' includes the coordination of initiatives into a structured programme of continuous improvement. There are already numerous initiatives underway in EGD, and our proposal includes the necessary alignment and prioritisation of these initiatives within an asset management framework. In particular, leveraging benefit from Envision is inevitably tied in with the intelligent use of the data, and the proposed programme will provide focus and (in many cases) define the way forward. It is therefore strongly recommended that consideration of an integrated AM Roadmap IS NOT DEFERRED until after Envision has been delivered.

2 The overall Roadmap

The workshops of 6-9th September yielded significant output – both in volume and quality. All of this material has been captured in a structured manner and is provided in electronic form (spreadsheets of assumptions, concerns, proposed actions, collated goals etc). The following is an assembly of the key conclusions and recommended actions resulting. However the final part of the road-mapping workshop was time constrained, so the team involved have not yet had sufficient chance to review and adjust the activity timings or sequencing in the light of other initiatives, resources and objectives. It should be expected, therefore, that the associated Gantt chart (see figure 1) will be significantly updated, firstly by the working team (prior to presentation to the EMT) and secondly, following the Strategic Planning meetings in early October.

3 Asset Management Goals

One of the more specific outputs from the workshops is a first cut definition of what EDG is aiming to deliver in improved management asset. This is an evolved ‘best combination’ of different component objectives, challenged for realism and the practical ability to demonstrate their achievement. This definition of EDG AM goals should provide an important starting point for clarification and alignment of what comprises good asset management within the company.

Workshop definition of the 3-5 year goal for AM:

EGD aims to be recognised by its customers, regulators, shareholders, employees and peer organisations as excellent in Asset Management (AM), providing a cost-, risk- and performance-optimised, and sustainable, gas distribution system.

It will achieve this through the establishment of an asset management culture and by successfully implementing and applying appropriate AM processes and methods (such as risk based decision techniques, continuous improvement, whole life costing and planning, appropriate competencies and multi-disciplined teamworking).

Regardless of the Regulatory regime, AM will allow us to justify better to the Regulator a more robust and defensible process for all of our expenditures, which will result in bottom line improvements in financial performance and risk management.

It is important that these goals are supported by measures and specific target ‘symptoms’ that can be used to align the organisation and demonstrate progress/success. The chosen ‘top 6’ such items (not in any particular order) were:

1. AM specific basket of KPI's in total scorecard (reliability, integrity, ROE, LCCost per customer, TSSA orders, PSRI & ratios)
2. Hosting AGA Asset Management Best Practice Workshop (2009)
3. Regulatory review - effort reduction & final decision
4. Demonstrable VP support (signed mandates & active participation in steering)
5. PAS55 certification (achievable ‘spin-off’ of getting the key elements in place)
6. Survey results of customer and staff perception of Enbridge AM performance

4 Main areas of attention and activity

There are a number of natural groupings within the Roadmap. These are:

4.1 Leadership, enablers & coordination

The sorts of things that will set the right environment, improve the acceptance, coordination and sustainability of the whole programme. These are very easy to overlook, or to allow slippage in priority/resourcing – yet make the biggest difference between a temporary enthusiasm and embedded, sustainable improved behaviours and results.

4.2 AM skills & resource development

Self explanatory; building the understanding and awareness necessary to deliver the programme and sustainability/succession competence. If you think such training is expensive – try putting a price on the alternative!

4.3 AM strategy development

The more technical activities needed to diagnose asset needs, criticality, risks, maintenance/investment strategies and priorities; the key decision-making elements of AM. In addition to the development of an overall approach (AM policy, clarity of direction, communication and awareness thereof), there are four main themes identified in this area, summarised below, and more detail of the specific actions and their resultant outputs are provided in Appendix A of this report.

4.3.1 Asset Health Review

This is the baseline exercise to determine the real profile of equipment and network condition. It provides the foundation, along with a profile of business criticality, for the future requirements for investment, asset renewal and maintenance. The roadmap includes two levels of such review – the first is a quick, high level, sample-based scan to provide the main indications and priorities. Thereafter, a more thorough, bottom-up data collection and collation exercise to provide the ongoing fact-based business process for investment planning, maintenance optimisation etc.

Task description:

- Stage 1: small team with data-mining and interview programme to generate first high-level asset health profile
- Stage 2: more rigorous, criticality-targeted data collection, probably linked in with existing work programmes and EnVision data gathering activities.

Deliverables:

- After Stage 1: Asset health profile for major asset groupings, clearer understanding of condition diversity and investment programme 'fit'.
- After Stage 2: More detailed profile and business process to use the data directly to influence operations planning, investment and maintenance strategy reviews.

4.3.2 Asset Criticality

The same equipment items or tasks have widely varied significance to the business in different functional locations and at different times. Also, the

various assets and activities are 'important' for different underlying reasons (e.g. safety, environmental protection, regulatory compliance, economic impact) – so a single clear 'criticality' definition is very valuable. The corresponding activities in the roadmap will generate this consistent structure for assigning importance and priority to systems, individual assets, projects and other activities, calibrated and visibly linked to the company's strategic objectives (and simply adjusted as these drivers change over time). The results will significantly affect investment priorities, performance indicators (calibrating or 'balancing' the scorecard) and maintenance/resource plans.

Task description:

- Small multi-disciplined team draft a criticality 'architecture' to combine different business drivers, and tables of severities or degrees of impact (aligned with scales of any corporate/strategic risk management system).
- Pilot application to a representative sample of assets, projects etc.
- Refinement, feedback and management approval steps essential.
- Rollout/application at systems level and, by discussion, targeted subsystems/individual assets/asset groupings.

Deliverables:

- Definition and scoring system for system, asset and task criticality.
- System-level profile of criticalities, with selective 'drill-down' to subsystems and asset groups/individual problems.

4.3.3 Investment strategy & Life Cycle Costing

The long term capital investment plan is a key deliverable for Enbridge – but this in turn relies on fact-based determination of what is needed and when. The combination of asset health and criticality (in combination with demand and growth predictions) determine the asset needs – and a transparent evaluation and prioritisation method is then needed to assess the best investment options and timings. This is a combination of business processes, education and analysis tools (such as Life Cycle Costing) – it also involves a big cultural change, as planning, budgeting, project performance measures and organisational responsibilities/accountabilities will be affected. The Roadmap includes a fairly complex sequence of preparatory steps and pilot studies to introduce and embed good practices, while building awareness and confidence (to minimise the resistance to change).

Task description:

- Investment strategy process review & refinement (to include asset condition, criticality and cost/risk evaluation of renewal/other options).
- Design, prove and implement Life Cycle Costing tool to evaluate renewal and investment options.
- Build the first 25-year capital programme/Long Range Plan.
- Embed investment review process into planning, budgeting and resourcing processes.

Deliverables:

- LCC tool
- Long Range Plan for asset investments
- Investment evaluation and prioritisation process

4.3.4 Maintenance strategy optimisation

A review of what maintenance is worthwhile, when, comprises one of the 'quick win' opportunities for Enbridge – but it also represents a new business process (the review and updating of such strategies). The toolbox approach that we suggest involves pilot studies (both to build confidence and demonstrate the quick wins) followed by criticality-prioritised systematic review, at progressively shallower levels of analysis detail and more 'batching' or template-derived methods for the low criticality elements.

Task description:

- Maintenance strategy process review & refinement (to include asset condition, criticality and cost/risk evaluation of maintenance options).
- Design, prove and implement maintenance optimisation tools to evaluate inspection, testing and planned maintenance strategies and intervals.
- Embed strategy review process into planning, budgeting and resourcing processes.

Deliverables:

- Maintenance Optimisation toolbox
- Revised intervals for testing and other inspection/maintenance tasks
- Maintenance strategy evaluation and optimisation process

4.4 AM delivery efficiency & effectiveness

The links to EnVision, work management and work delivery. Clearly a vital 'closing of the loop' and one that should actually release many of the benefits currently ascribed to EnVision alone.

In many of these areas there are short-term clarification, planning, pilot studies or 'quick win' activities, and it may prove valuable to split these out into the suggested preparation phase, leading to a revised (first) rollout phase, corresponding to the two practical timescales we have mentioned in this regard, namely a 12-month specific plan (with details of who will do what, when, why and with what target deliverables), and a more strategic 3-5 year sequence of initiatives and goals. This re-grouping and increased level of specification should be considered once the total picture has been discussed for value, appropriateness and deliverability.

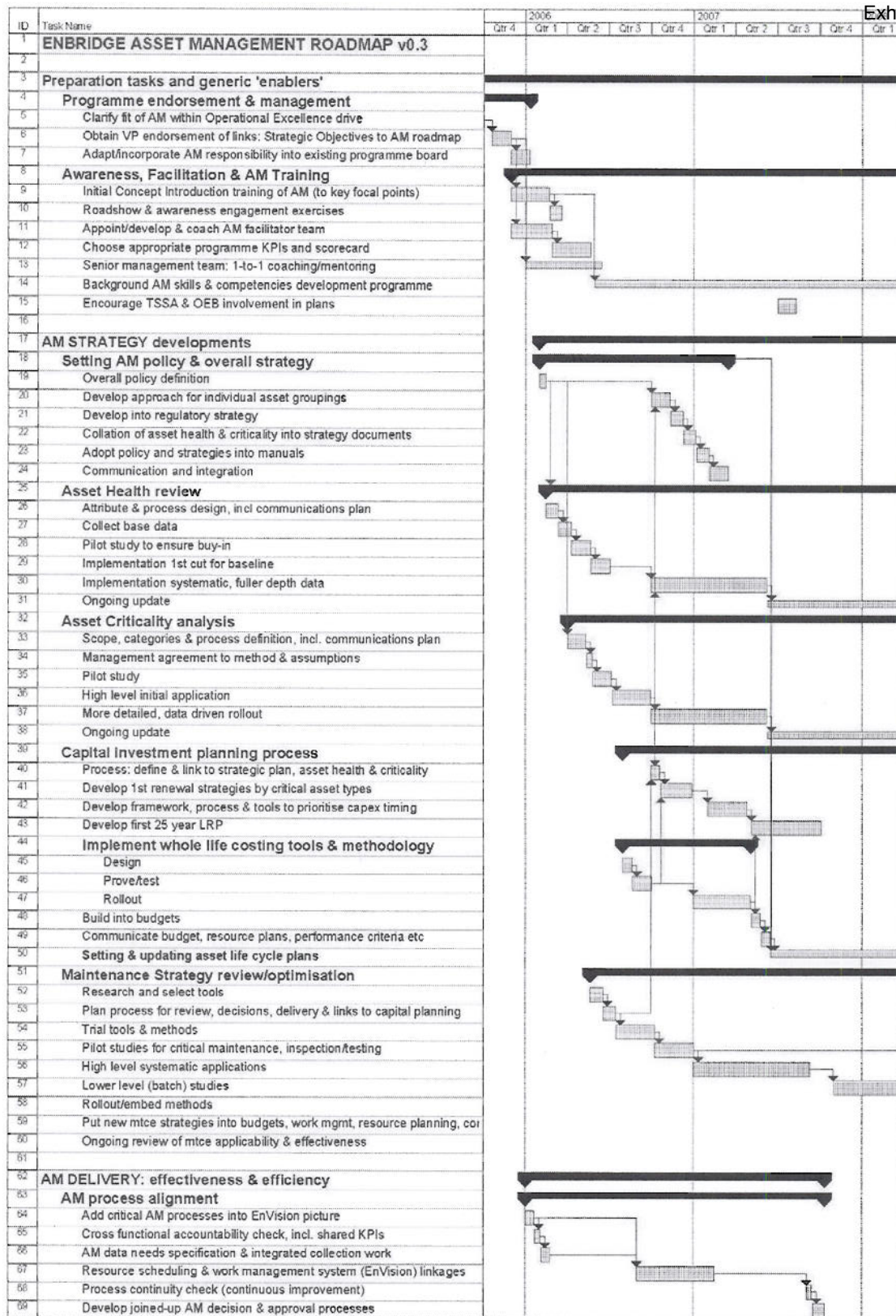


Figure 1 Draft Roadmap (version 0.3)

5 Business case

The costs and potential benefits for such an integrated approach to managing EDG assets fall into two groups:

- Activities that are 'must do' items anyway – where the questions are merely how urgently and how best to address the subject
- Added value activities, that will harness existing good practices, release new business performance or avoid unnecessary costs.

It should be recognised that many of the suggested items are associated with better organising of activities that are either already underway or recognised as necessary. Therefore a high proportion of the resource is effectively already committed by EGD, and there are likely to be cost and resource efficiencies coming out of organising them into a co-ordinated framework. Furthermore, to deliver some of these outputs, several other items in the programme are necessary precursors or feeder/enabler activities. For example:

The 25 year Long Range Plan

- > needs a robust Capital Investment Planning process,
 - > which needs knowledge of asset condition/health,
 - > and a consistent basis and mechanism for defining criticality.
- > and all of these elements are only likely to be credible and effective if there is adequate understanding of objectives, performance criteria, tools (including Whole Life Costing) and data requirements & usage.

5.1 Benefits

The combined programme, therefore, can largely be justified on the basis of component steps needed to delivery existing objectives and undertakings. On the other hand, there are clearly tangible business opportunities associated with addressing these areas also. These include:

- 1 Improve internal efficiencies by reducing overlaps & process misalignments
- 2 Reduce some operational costs by removing ineffective tasks & optimising test intervals.
- 3 Shift some asset care expenditure from O&M to capital – both the immediate benefit arising from the nature of the regulatory mechanism, and the secondary opportunities released by demonstrating such shifts to be the best practice long-term solution. For example: numerous repairs to existing equipment results in poor performance and high O&M cost – timely replacement improves all aspects of the EGD 'bottom line'.
- 4 Improve performance effectiveness by prioritising & coordinating initiatives.
- 5 Negotiate future regulatory strategy from position of greater strength (defensible audit trail for plans & expenditures).
- 6 Position the company to take advantage of competitive opportunity by being able to demonstrate how value can be leveraged from business acquisitions.
- 7 Improve support to staff & relieve observed stress / risk of future poor performance.

Of these, the most obvious realisable financial benefit lies in number 3 (the likely shift resulting from criticality-targeted elimination or conversion of maintenance expenditure to selective asset replacement (capital investment to eliminate operating expenditure or raise performance). Even if only 2% of the current 'non-customer service' O&M spend is affected this way, this represents a value of **\$0.5-5 million/year** (extrapolated from 2003 figures). Track records elsewhere indicate this sort of shift is very conservative. This gives us great confidence that the entire roadmap will be, at very least, self-funding.

Figures realised for the re-targeting of maintenance expenditure elsewhere have shown consistent ranges of 25-40% of asset maintenance costs are at stake. It is recognised that EGD have already made big savings in this area, therefore our estimate of potential saving would be at the conservative end of this spectrum, and likely to arise from the alteration of inspection intervals and discontinuance of ineffective tasks. Of course, EGD cannot realise the operating cost reductions that these represent under the current regulatory regime, but there are tangible opportunities in revising test intervals and elimination of low-value activities to concentrate on, or accelerate, higher criticality tasks. Prior to pilot studies, it is difficult to estimate the realisable benefits from this area, but other utility networks have been able to shift 25-30% of low-criticality maintenance, inspection or testing onto higher criticality or urgency activities.

And the key "*enablers*" (of education, communication, KPI's and facilitation) are often the ultimate differentiators between just temporary enthusiasms and sustainable realisation of benefits. One of the lessons from the recent Envision experience is that adequate communication, education and process alignment are necessary factors for success.

The *combination* of visible, logical asset management strategy, the targeted application of that strategy to both asset investment and asset care (maintenance), and tracking of resulting performance and effectiveness to continuously improve ('closing the loop') comprises an exploitable and demonstrable competence in asset management. Therein lie probably the biggest opportunity and deliverables for the Roadmap: providing the credibility and evidence to back up EGD's case for a revised regulatory model. The same demonstrable competence can be exploited in the mergers and acquisitions area – if EGD wishes to broaden its influence and asset portfolio (AM skills are largely transferable).

5.2 Costs

As already described, it is anticipated that many of the internal costs are effectively already committed, and we are discussing the more structured use of existing resources and alignment of programmes. The new costs of implementing the roadmap, therefore, are not as large as many would expect – provided the resources are targeted (by criticality and iterative, step-wise rollout). Many of the principal initiatives (e.g. criticality assessment, asset health review, maintenance strategy review) comprise initial design and piloting activities, followed by initial high level application. What is necessary, however, is the assignment of an appropriate multi-disciplined team (usually 4-6 persons) to drive each of these – typically for a high intensity period of 3-6 months to achieve at least the first level targeted rollout.

The other items of vital commitment lie in the *enabler* areas of training, communication and facilitation (including visible management participation and leadership). Our first estimates for 'concepts introduction' levels of training might represent costs of \$100-200k and include:

- Preparation and widespread delivery of roadshow (probably 2-4 hours) to field force.
- 1-to-1 briefings and mentoring for senior management team over 3-4 months.
- Small team 'total picture' training in range of AM concepts, tools & implementation skills (typically 4 weeks total over 6-12 months).

- Selective task-force/team training in component methods (such as Life Cycle Costing, Criticality, Maintenance Strategy methods etc) – short courses of 2-3 days each.

Other cost items include the development/acquisition of various AM tools. These, with typical staged implementations and associated training and services, would cost in the range of \$300-400k/year for the first 3 years, tailing down to c.25% of this figure subsequently.

Important note: estimates for both costs and benefits can be significantly improved during the first phases of individual activity specification, trials and pilot studies. In most cases, such proving exercises identify specific benefits sufficient to 'fund' the more systematic refinements and rollouts, so that the AM programmes become 'self-funding'. In Enbridge's case, this may not represent immediately realisable benefits, but the cumulative and strategic impact will become increasingly clear as examples accumulate.

Appendix A Summary of Principal Elements in Asset Management Roadmap

Workstream	Summary	Purpose	Key Elements
Asset Health Review	Review of asset issues including condition & performance. Initially achieved using structured cross functional meetings, the asset health review becomes a regularly updated living document. This is both a record of current condition/performance for assets and the basis for improvement in strategy and prioritised actions.	• Overview and common understanding of asset status across the business (up to board level). • Enables significant issues to be identified, and appropriate action initiated. • Provides a framework for structured feedback from knowledgeable staff – leading to retention of corporate knowledge. • Provides the technical justification to support asset strategy – e.g. capital plan. • Provides a mechanism for co-ordination and alignment of best practice integrated across processes • Focus for reporting of asset performance and condition – clear and aligned reporting requirements. • Provides a framework for the developing data based decisions and the use of decision support tools	• Start up - agree process, scope, resources and timescales. • Communication – presentations and communications • Pilot – identify scope (assets) & team. Collect data. 2/3 meetings to produce result for an asset grouping. • Review of pilot – improvement/adjustment. • Integration into processes – detailed discussion with key staff – process ‘owners’, business planners. Agree use to drive change. • Rollout – set out detailed programme, templates for review, collation of data, train facilitators. • Report production – production of reports (management and asset level), recommendations, actions • Endorsement/sanction – 1-2 iterations to agree content with key staff and presentation to gain endorsement. • Embedding long term solution – design of reporting to provide data for future reviews, design of electronic access via intranet, review of frequency for updates, accountabilities, process, and integration of asset criticality analysis.

Workstream	Summary	Purpose	Key Elements
Asset Criticality Analysis	Development of a mechanism to prioritise assets based on their total business contribution. Including their contribution to EGD's risks and opportunity. This will deliver a ranked list of assets based on their criticality to the business, and enable options to be compared and prioritised.	- Will support and be integral to the Asset Health Review Targets best use of resources - Provides an objectively ranked list of assets based on overall business priority. - Use of priority will enable the development of a long term strategic plan Demonstrable good stewardship Alignment of business decisions with management of strategic risk	Start up – launch meeting, scope, development of EGD specific criteria. Development – design of appropriate solution (spreadsheet/database solution). Endorsement – iteration of solution, endorsement, agree resources. Communication – buy in from key staff. Pilot study – trial, fine tuning, review Rollout – training, communication, integration into processes (e.g. capital planning, asset health review), implementation across asset base, integration into, alignment with corporate risk etc.
Asset Management Policy	Documents setting down the policy and strategy clearly for EGD on how each major asset management activity (for example maintenance) is managed	- Provides clear and consistent guidance to improve understanding and consistency in applying best practice. - Ensures that communication with external parties (e.g. regulator) is managed consistently and efficiently - Auditable reference to support new detailed documents	Start up – Launch meeting to key staff, identify resources & reporting/endorsing mechanism, agree scope and timetable. Pilot – Trial on one process/asset type, draw up format develop and deliver. Review – feedback from pilot, management review, adjustment of format and design Roll out – set up task teams/individuals using templated documentation and process, managed delivery plan. Endorsement – management team including regulation Integration – integration into processes and document suite

Workstream	Summary	Purpose	Key Elements
Capital Investment Planning	Develop a capital plan and associated process to provide long term and short term investment plans based on asset management best practice integrated with the business plan and budget.	• Provides a long term forecast of capital requirements consistent with ensuring funding provision is available. • Connects budget with the strategic plan. • Ensures that appropriate priority is given to priority work • Balances capital and revenue solutions to give the best business mix, and avoids unnecessary operational expenditure • Manages long term sustainability of the business • Essential to negotiate in an incentivised regulatory environment • Management of strategic risk	• Set up – launch meeting to key staff, scope and agree requirements, resources and staged delivery • Pilot – Limited scope trial using priority assets and task team. Training, development of process and methods. Produce limited scope short and long term plans, identify interfaces and process requirements. • Review of pilot – check stage with management team, endorsement for progressing rollout. • Training – methods and techniques, aligned to EGD requirements • Rough cut plan – Building on the output of the asset health review and criticality exercise, identify priority candidates for asset replacement. • Business case development – Build business cases for critical assets & high value decisions, simplified business cases to support other decisions. Develop templates and consistent approach. • Integration into business – integrate with strategic planning, local capital planning, budget process, risk management, maintenance strategy, asset health review. Communication and governance of finance processes. • Development and rollout – increasing detail and accuracy of plan, improved financial modelling including whole life costing.

Workstream	Summary	Purpose	Key Elements
Whole Life Costing	Training in the use of whole life costing techniques. Application of this approach by EGD to use financial and engineering data to support investment decisions and the optimisation of alternative asset management solutions.	• Ensure that high value investment decisions are properly justified and supported by business cases • Provide evidence to support business plan to stakeholders including regulators • Ensure best value to EGD for investment and operational expenditure mix. • Consistent approach for all assets for critical decisions • Approach supports sustainable business, and is the most appropriate for long lived assets	• Training – skill transfer to appropriate staff, and an appreciation of requirement to most engineering and financial staff. • Facilitated trials – assisted application to some assets, EGD staff working with TWP staff. • Roll out – Determination of appropriate techniques to be applied including value of decisions/asset types. Endorsement by management. Installation of software/training. Embedding of techniques into business processes (e.g. capital planning, budgeting)
Maintenance Optimisation	Application across EGD of a consistent approach to the testing and maintenance of equipment based on cost/risk/performance optimisation.	• Ensures that maintenance strategy is defensible if challenged by stakeholders (e.g. regulator), or following an incident • Reduction in costs through removal of ineffective tasks and optimisation of inspection/maintenance intervals • Demonstrable risk management – e.g. evaluation of predicted reliability • Optimised mix of operational cost and capital investment (ability to compare alternative whole life strategies)	• Training – skill transfer to appropriate staff, and an appreciation of requirement to most engineering and financial staff. • Facilitated trials – assisted application to some assets, EGD staff working with TWP staff. • Roll out – Determination of appropriate techniques to be applied including value of decisions/asset types. Endorsement by management. Installation of software/training. Embedding of techniques into business processes (e.g. capital planning, budgeting)

SEC INTERROGATORY #139

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 20] Please restate Table 1 replacing the figure "Quantity" on each line with the net dollars in rate base at that time.

RESPONSE

The following table shows the Plant balances of the items by asset category.

Line Item			Depreciable Plant Balance at March 31, 2013 (\$M)
1	473/4	Services & Meter Installations	2,256
2	475	Mains	
3	475	Mains - plastic	1,544
4	475	Mains - coated & wrapped steel	1,094
5		Subtotal: Mains	2,638
6	477	Regulating Equipment	355
7	478	Meters	393
8		Total Depreciable Plant (Services, Mains, Measurement and Regulation)	5,642

The table on the following page shows the above balances in the format per the table at Exhibit B2, Tab 10, Schedule 1, page 20.

Witness: L. Lawler

Distribution Asset Classes		Quantity	Rate Base \$M
Pipe			
Mains (km)		36,665	2,638
	Cast Iron	-	
	Bare Steel	3	
	Coated Steel	13,128	
	Plastic - Vintage	3,760	
	Plastic - Other	19,774	
	Unclassified	-	
Services (#)		1,998,682	2,256
	Copper	7,063	
	Bare Steel	29,317	
	Coated Steel	154,797	
	Steel Tubing	283	
	Plastic - Vintage	283,523	
	Plastic - Other	1,523,680	
	Unclassified	19	
Measurement & Regulation			748
Gate Stations (#)		44	
Feeder Stations (#)		19	
District Stations (#)		2,118	
Header Stations (#)		2,418	
Sales Stations (#)		9,991	
Customer Meter Sets (#)		2,098,342	
Main & Station Valves			
Main Line Valves (#)		20,527	
Station Valves (#)		11,200	
Unclassified		8	
			5,642

Witness: L. Lawler

SEC INTERROGATORY #140

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 32] Please confirm that, for the ten year period 2012 through 2021, Chart 5 forecasts customer additions totalling 389,528. Please confirm that the 2012 Asset Plan, for the same period, forecast customer additions totalling 403,215. With respect to this difference:

- a. Please explain the primary reasons for the 3.4% decrease in the customer additions forecast over that period.
- b. Please confirm that the Company's application in EB-2011-0354 was consistent with the customer additions in the 2012 Asset Plan with respect to the revenue forecast, the O&M forecast, and the capital expenditures forecast. If there are inconsistencies, please provide details of each including reasons.
- c. Please confirm that the Company's application in EB-2012-0459 is consistent with the customer additions in the 2013 Asset Plan with respect to the revenue forecast, the O&M forecast, and the capital expenditures forecast. If there are inconsistencies, please provide details of each including reasons.

RESPONSE

- a. A vast majority of customer additions come from Residential New Construction sector, which has recently exhibited weaker than expected growth. This weaker trend has been reflected in 2013 Asset Plan and is the primary reason for 3.4% decrease in customer additions over the forecast horizon.
- b. The revenues, O&M and capital expenditures forecasts in the EB-2011-0354 application are consistent with the customer additions in the 2012 Asset Plan.
- c. The revenues, O&M and capital expenditures forecasts in the EB-2012-0459 application are consistent with the customer additions in the 2013 Asset Plan.

Witnesses: F. Ahmad
F. Smith

SEC INTERROGATORY #141

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 35] Please confirm that, for the ten year period 2012 through 2021, Chart 6 forecasts direct customer additions capital of \$996.267 million. Please confirm that the 2012 Asset Plan, for the same period, forecast direct customer additions capital of \$869.647 million. With respect to this data:

- a. Please explain the primary reasons for the 14.6% increase in the direct customer additions capital forecast over that period.
- b. Please confirm that the 2012 Asset Plan resulted in an average direct customer additions capital, per customer addition, of \$2,156.78 over that period, while the 2013 Asset plan results in an average direct customer additions capital, per customer addition, of \$2,557.63 over that period, an 18.6% increase.
- c. Please provide details of the primary reasons the capital cost per customer addition increased by 18.6% in the one-year period between one asset plan and the next.

RESPONSE

- a) When comparing the 2013 Asset Plan to the 2012 Asset Plan for the ten year period on 2012 through 2021, the increase is \$126.6M or 14.6%. There are two main reasons for the increase. Inflation was not considered in the 2012 Asset Plan. The 2013 Asset Plan assumes a 2% inflation escalation in each year following 2012. This accounts for \$70.7M of the increase. The remaining increase is due to higher direct costs anticipated in the 2013 Asset Plan partially offset by decreased customer additions relative to the 2012 Asset Plan.
- b) Please see the table below which shows the variances between the 2013 Asset Plan as compared to the 2012 Asset Plan.

Witnesses: F. Ahmad
F. Smith

Comparison of 2013 Asset Plan vs. 2012 Asset Plan: Ten Years (2012-21) of Customer Attachment Data					
		Col 1	Col 2	Col 3	Col 4
Line Item		2013 Asset Plan	2012 Asset Plan	Variance	Percentage Variance
1.0	Customer Additions 2012-21	389,528	403,215	(13,687)	-3.4%
2.0	Customer Additions Capital 2012-21:				
2.1	Pre Inflation	925,607	869,687	55,920	6.4%
2.2	Inflation Impacts	70,659		70,659	
2.3	Customer Additions Capital	996,266	869,687	126,580	14.6%
3.0	Average Cost per Customer Addition	\$ 2,558	\$ 2,157	\$ 401	18.6%
4.0	Unit price Variance due to Inflation			\$ 181	8.4%
4.1	Unit price Variance due to Cost pressures			\$ 219	10.2%
4.3					18.6%

- c) Customer additions are driven by economic conditions, forecasts anticipated by the builder community among other factors as described in the Customer Growth Capital evidence filed at Exhibit B2, Tab 2, Schedule 1. There would have been a re-evaluation of the customer growth requirements for the 2013 Asset Plan scenario. The primary factors that influence the average cost per customer are the mix of customer additions and service types (i.e., replacement versus new construction, residential versus commercial or industrial), mix of meter types and length of main required for the customer addition. As shown in the table above, the 2013 Asset Plan was based on a revised set of assumptions as compared to the 2012 Asset Plan. The 2013 Asset Plan includes inflation where the 2012 Asset Plan did not; this would account for 8.4% of the 18.6% variance. The remaining variance is due to other cost pressures. For example, the mix of customers in the 2013 Asset Plan includes more Residential Replacement customers. These customers are more expensive to attach versus New Construction customers. Also, the 2013 Asset Plan included the re-negotiated contract prices with the Company's extended alliance contractors, which are higher by around 5% as compared to the forecast costs contained within the 2012 Asset Plan.

Witnesses: F. Ahmad
F. Smith

SEC INTERROGATORY #142

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 54] Please confirm that, for the ten year period 2012 through 2021, Chart 7 forecasts routine reinforcements direct capital of \$172.728 million. Please confirm that the 2012 Asset Plan, for the same period, forecast routine reinforcements direct capital of \$174.762 million.

RESPONSE

The 2013 Asset Plan shows routine reinforcement direct capital of \$172.728 million for 2012 through 2021. Also, the 2012 Asset Plan shows routine reinforcement direct capital of \$174.762 million for the same period. The Asset Plan is an iterative document that is regularly updated. As such, based on operational needs, projects can be deferred, advanced, cancelled or deferred beyond the scope of the Asset Plan resulting in differences in a ten year projected total spend.

Witness: L. Lawler

SEC INTERROGATORY #143

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 61] Please advise whether the previous integrity management process included a focus on "striving to better understand threats and related risks to the distribution system". If it did, please explain how the new process changes that risk-based analysis in material ways.

RESPONSE

EGDI has always had a strong focus on "striving to better understand threats and related risks to the distribution system" and this focus continues. Since 2001, EGDI developed the Integrity Management Program associated with assets operating over 30% SMYS. Under this program pipelines over 30% Specified Minimum Yield Strength ("SMYS") have been inspected through in-line inspection or direct assessment and remediated accordingly to mitigate risks.

As well, condition monitoring programs such as Leak Survey and Corrosion Survey have contributed to understanding the condition of the assets and have led to studies and remediation programs. Asset information data associated with leak survey, corrosion survey, and maintenance repairs is analyzed as part of the Distribution System Integrity Management Program ("DSIMP"), for lines operating below 30% SMYS in order to understand which lower stress assets are impacted by threats and risks, thus enabling the Company to prioritize and target mitigation programs more effectively.

An example is the AMP fitting program that has recently been implemented. Over the past number of years, EGDI has been analyzing the increasing failures associated with AMP fittings, and determined that these fittings are failing at an accelerated rate. Instead of implementing a replacement program based solely on the increasing number of leaks, using a risk-based approach, EGDI conducted an extensive study to identify the root cause of the failures, the associated contributing factors to failures, and developed a predictive model to apply to the entire system population of AMP fittings. The work concluded that the AMP fitting failure rate will continue to increase and an aggressive replacement program is needed to mitigate the risk associated with AMP failures. Please see Exhibit B2, Tab 5, Schedule 3, Attachment 2.

Witness: L. Lawler

SEC INTERROGATORY #144

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 64] Please describe what is meant by "tacit knowledge interviews". Please provide a summary of the "existing asset condition monitoring programs".

RESPONSE

In the context of the Asset Plan, tacit knowledge interviews are a means of gaining first hand and supplemental information from subject matter advisors on assets. This information is necessary to perform a qualitative assessment of risk associated with the assets based on the advisors' knowledge and experience with those assets.

Existing asset condition monitoring programs are the day-to-day activities that can be used to assess the condition of our assets to provide early indication of incipient failures and their causes. The existing asset condition monitoring programs include:

- Material Fault Reporting Program
- Gas Storage & Transmission System Integrity (in-line inspection and assessment)
- Valve Inspection and Repair
- Leak Management (survey, repair and monitoring)
- Bridge and River Crossing Inspections
- Cathodic Protection Survey
- Scheduled Patrols
- Regulator Inspection and Repair
- Depth of Cover Survey

Witness: L. Lawler

SEC INTERROGATORY #145

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, pp. 65-70] Please provide a side by side comparison of this risk register with the similar risk register on pages 48-49 of the 2012 Asset Plan. In that comparison:

- a. Please identify all 2012 risks that are no longer listed, and explain why.
- b. Please identify all 2012 risks that have been materially expanded or altered, and explain why.
- b. Please identify all risks that are new in 2013, and explain why they were not included in the 2012 risk register.
- d. Please provide any previous "risk registers" or similar documents listing risks for the period 2007 through 2011.

RESPONSE

- a. The following are all 2012 risks that are no longer listed:

Risk	Reason
Cast Iron Mains	Program has been completed and cast iron mains have been removed from the system.
Bare Steel Mains	Program has been completed and bare steel mains have been removed from the system.
Steel Tubing	This asset was being addressed through the ongoing Service Relay program. No longer listed as a risk as it was treated as an inherent risk to the normal operation of the utility.
Expansion Joint	This asset was being addressed through the annual bridge crossing inspection. No longer listed as a risk as it was treated as an inherent risk to the normal operation of the utility.
Encased Bridge Crossing	Is on the Risk register but is a Priority 4.

Witness: L. Lawler

b. The following are all 2012 risks that have been materially expanded or altered:

Risk	Reason
ILI Scope and Technology	Expanded: Name changed to <i>High Stress Steel Mains</i> . The risk expands to selected pipelines operating between 20% and 30% SMYS as well as all lines operating over 30% SMYS.
Plastic Mains	Altered: Risk name changed to <i>Vintage Plastic Mains-Pre 1982</i> . This better reflects the risk of brittle-like cracking in the plastic main.
Gate Station Components	Altered: Separated to address the following risk: <i>Gate Station (and Feeder Stations), Heating Systems, Odorant and SCADA/ Telemetry</i> . These additional risks were part of Gate Station Components because they have different risk scenario for each asset, they were separated out to provide insight into the risk.
Isolation Valves	Altered: Combined with <i>Load Shed Zones</i> resulting in <i>Reliability of Supply</i> . Isolation Valves and Load Shed Zones are addressing the same risk of not being able to isolate sections of the system in case of emergency. Reliability of Supply encompasses the risk of the inability to isolate portions of the system.
Load Shed Zones	Altered: Combined with <i>Isolation Valves</i> resulting in <i>Reliability of Supply</i> . See <i>Isolation Valves</i> for comments.

c. The following are all risks that, although not new to the Company, are new to the risk register in 2013, identified by the Subject Matter Advisors ("SMA's"). The risk register is a living document, and as such it is intended to identify all risks in a centralized location to ensure they are being addressed systemically.

Risk	Reason
Isolated Steel Mains	New risk identified by SMAs.
Pipelines in AC Susceptible Areas	New risk identified by SMAs.
Vintage Steel Network	New risk identified by SMAs.
Meter Boxes	New risk identified by SMAs.
Plastic Services	New risk identified by SMAs.
Plastic Services with EFV	New risk identified by SMAs.

Witness: L. Lawler

Stand Pipes	New risk identified by SMAs.
Steel Services	New risk identified by SMAs.
XHP/HP Services Close to Building	New risk identified by SMAs.
Blow Off Valves	New risk identified by SMAs.
Isolation Valves (Separating pressures)	New risk identified by SMAs.
Bare Steel Drips	New risk identified by SMAs.
Tap-n-Valve Tee	New risk identified by SMAs.
Vintage Plastic Service Tee cap	New risk identified by SMAs. This asset is similar to <i>Plastic Punch Tee Caps</i> as they pose the same risk scenario, a leaking service cap.
Header Station	This asset is very similar to <i>District Stations</i> but is on private right of way. This was included so the same programs that address <i>District Stations</i> also address <i>Header Stations</i> .
Heating System	This asset was part of the general 2012 <i>Gate Station Components</i> risk. This asset posed a different risk to the asset than the one identified in 2012 hence it was separated.
Load Changes for Customers	New risk identified by SMAs.
Multi Cut regulators	This asset is similar to <i>District Stations</i> in terms of the components used. This was included so the same programs that address <i>District Stations</i> also address <i>Multi Cut regulators</i> .
Odorant	The odorant system was part of the general 2012 <i>Gate Station Components</i> risk. This system posed a different risk to the asset than the one identified in 2012 hence it was separated.
Pounds Delivery Stations	This asset is similar to <i>District Stations</i> in terms of the components used. This was included so the same programs that address <i>District Stations</i> also address <i>PSI Delivery Stations</i> .

Regulator Enclosure	This scenario is similar to Inside Regulators as they pose the same risk scenario, a regulator located in an enclosed area.
Regulator	New risk identified by SMAs.
Regulator Vent Protection	New risk identified by SMAs.
SCADA/ Telemetry	This SCADA / Telemetry system was part of the general 2012 <i>Gate Station Components</i> risk. This asset posed a different risk to the asset than the one identified in 2012 hence it was separated.
Single Cut Regulator	New risk identified by SMAs.
Tracer Wire	New risk identified by SMAs.
Single Source Feed (Upstream Supply)	New risk identified by SMAs.

- d. A consolidated list of risks for all assets, ranked relative to each other, had never been formally produced prior to 2012. However, the Integrity Management Program associated with pipelines operated above 30% SMYS were managed within a risk framework. The following tables identify the consolidated risk view associated with the high stress pipelines for the period from 2007 to 2011 for EGD and Enbridge Gas Storage ("EGS").

Top 10 EGD Integrity Mains in Order of Risk Contribution for 2007

Rank	Pipeline Description	Pipeline Index	Length (km)	% Total Risk
1	NPS 30 Don Valley	N182_84_116_OD30	35.25	29.5 %
2	NPS 8 Collingwood	N5301_145_176_OD8	55.58	28.0 %
3	NPS 36 Parkway North	N182_358_376_OD36	39.04	8.6 %
4	NPS 26 Keele/CNR to Don Valley	N182_82_247_OD26	13.87	4.8 %
5	NPS 12 Ottawa South	N6581_1946_815_OD12	7.64	4.3 %
6	NPS 16 Markham to Neilson	N3784_24_100_OD16	14.25	3.3 %
7	NPS 12 Ottawa North	N6580_469_9943_OD12	5.91	2.9 %
9	NPS 24 Winston Churchill Pine Valley	N2182_89_102_OD24	38.86	2.0 %
10	NPS 12 Richmond Gate	N6581_657_9813_OD12	24.81	2.0 %
N/A	Remaining Pipelines	N/A	118.78	11.8 %
Total			368.35	100.0 %

Comparison of the Top 10 Risk Contributing EGD Integrity Mains for 2008 and 2009

Rank		Pipeline	Length (km)	% Total Risk	
2008	2009			2008	2009
1	1	NPS 8 Collingwood	55.47	21.2%	42.0%
2	2	NPS 30 Don Valley	35.25	18.1%	20.4%
5	3	NPS 26 Keele/CNR to Don Valley	13.84	5.9%	5.8%
4	4	NPS 12 Ottawa South - Hunt Club Rd	9.11	7.3%	4.4%
9	5	NPS 24 Winston Churchill Pine Valley	39.00	3.2%	4.1%
3	6	NPS 36 Parkway North	39.04	12.9%	4.1%
10	7	NPS 12 Ottawa South - Fallowfield Rd	24.81	2.7%	3.2%
6	8	NPS 16 Markham to Neilson	14.21	5.7%	3.2%
8	9	NPS 12 Ottawa North - OGS to St. Laurent	5.91	4.5%	2.6%
N/A	N/A	Remaining Pipelines	92.66	17.1%	8.5%
Total			333.49	100%	100%

Witness: L. Lawler

Comparison of the Top 10 Risk Contributing EGD Integrity Mains for 2009 and 2010

Rank		Pipeline	Length (km)	% Total Risk	
2009	2010			2009	2010
1	1	NPS 8 Collingwood	55.56	42.0%	50.9%
2	2	NPS 30 Don Valley	35.25	20.4%	21.3%
3	3	NPS 26 Keele/CNR to Don Valley	13.87	5.8%	5.9%
4	4	NPS 12 Ottawa South - Hunt Club Rd	9.11	4.4%	4.5%
6	5	NPS 36 Parkway North	39.04	4.1%	4.3%
7	6	NPS 12 Ottawa South - Fallowfield Rd	24.81	3.2%	3.3%
9	7	NPS 12 Ottawa North - OGS to St. Laurent	5.91	2.6%	2.6%
N/A	9	NPS 16 Ottawa E- OGS to Blackburn Bypass	11.39	1.6%	1.5%
N/A	10	NPS 12 Victoria Square North	24.05	1.5%	1.3%
N/A	N/A	Remaining Pipelines	36.34	12.7%	2.7%
Total			259.45	100%	100%

Comparison of the Top 10 Risk Contributing EGD Integrity Mains for 2010 and 2011

Rank		Pipeline	Length (km)	% Total Risk	
2010	2011			2010	2011
1	1	NPS 8 Collingwood	55.56	50.9%	56.9%
2	2	NPS 30 Don Valley	35.25	21.3%	21.2%
3	3	NPS 26 Keele/CNR to Don Valley	13.87	5.9%	4.8%
4	4	NPS 12 Ottawa South Hunt Club Rd	9.11	4.5%	3.6%
5	5	NPS 36 Parkway North	39.04	4.3%	3.4%
6	6	NPS 12 Ottawa South - Fallowfield Rd	24.81	3.3%	2.7%
7	7	NPS 12 Ottawa North - OGS to St. Laurent	5.91	2.6%	2.2%
9	8	NPS 16 Ottawa E- OGS to Blackburn Bypass	11.39	1.5%	1.2%
10	9	NPS 12 Victoria Square North	24.05	1.3%	1.1%
N/A	N/A	Remaining Pipelines	26.06	3.31%	1.9%
Total			259.44	100.0%	100.0%

Witness: L. Lawler

Top 10 EGS IMP Pipelines in Order of Total Risk - 2007

Rank	Line	Length (m)	% of Total Risk
1	Dow Moore NPS 24 Transmission	7,494	2.0 %
2	Mid Kimball - Colinville NPS 24 Transmission	817	1.7 %
3	Dow Moore Gathering - Line B	465	1.6 %
4	Dow Moore Gathering - Line C	805	1.6 %
5	Dow Moore Gathering - Line D	837	1.6 %
6	Ladysmith NPS16 Gathering	1,634	1.5 %
7	Ladysmith #6 Wellhead Line	8	1.5 %
8	Ladysmith #7 Wellhead Line	8	1.5 %
9	North Mid Kimball - Colinville Gathering	1,474	1.5 %
10	Ladysmith #5 Wellhead Line	8	1.5 %
N/A	Remaining Lines	100,448	84.1 %
	TOTAL	114,000	100.0 %

Top 10 EGS IMP Pipelines in Order of Total Risk 2008

Rank	Line	Length (m)	% Total Risk
1	Dow Moore NPS 24 Gathering	7,494	2.1%
2	Mid Kimball - Colinville NPS 24 Gathering	817	1.8%
3	Tec Dow 11 Wellhead Line	13	1.7%
4	Ladysmith NPS16 Gathering	1,634	1.7%
5	D_Dow Moore Gathering	837	1.6%
6	TL #6 Wellhead Line	8	1.6%
7	TL #7 Wellhead Line	8	1.6%
8	North Mid Kimball - Colinville Gathering	1,474	1.6%
9	TL #5 Wellhead Line	8	1.5%
10	A_Dow Moore Gathering	690	1.5%
N/A	Remaining Lines	101,016	83.3%
	Total	114,000	100.0%

Witness: L. Lawler

Comparison of the Top 10 Risk Contributing EGS Integrity Pipelines for 2008 and 2009

Rank		Line	Length (m)	% Total Risk	
2008	2009			2008	2009
1	1	Dow Moore NPS 24 Gathering	7,494	2.1%	2.0%
2	2	Mid Kimball - Colinville NPS 24 Gathering	817	1.8%	1.7%
3	3	Tec Dow 11 Wellhead Line	13	1.7%	1.6%
N/A	4	1964 Corunna - Dawn NPS 30 Transmission	19,530	N/A	1.6%
4	5	Ladysmith NPS16 Gathering	1,634	1.7%	1.6%
8	6	North Mid Kimball - Colinville Gathering	1,474	1.6%	1.6%
N/A	7	South Mid Kimball - Colinville NPS20 Gathering	2,815	N/A	1.6%
5	8	D_Dow Moore Gathering	837	1.6%	1.6%
N/A	9	1977 Corunna - Dawn NPS 30 Transmission	19,714	N/A	1.6%
6	10	TL #6 Wellhead Line	8	1.6%	1.5%
N/A	N/A	Remaining Lines	54,336	83.3%	83.8%
Total			108,067	100.0%	100.0%

Comparison of the Top 10 Risk Contributing EGS Integrity Pipelines for 2009 and 2010

Rank		Line	Length (m)	% Total Risk	
2009	2010			2009	2010
2	1	Mid Kimball - Colinville NPS 24 Gathering	817	1.7%	1.82%
4	2	1964 Corunna - Dawn NPS 30 Transmission	19,529.88	1.6%	1.81%
9	3	1977 Corunna - Dawn NPS 30 Transmission	19,714.36	1.6%	1.80%
5	4	Ladysmith NPS16 Gathering	1,634.00	1.6%	1.68%
6	5	North Mid Kimball - Colinville Gathering	1,474.46	1.6%	1.68%
7	6	South Mid Kimball - Colinville NPS20 Gathering	2,815.03	1.6%	1.66%
8	7	D_Dow Moore Gathering	837	1.6%	1.65%
N/A	8	A_Dow Moore Gathering	689.7	N/A	1.54%
N/A	9	Wilkesport - Coveny Link NPS16 Transmission	2,161.04	N/A	1.53%
10	10	TL #6 Wellhead Line	8.49	1.5%	1.38%
N/A	N/A	Remaining Lines	64,319.04	83.8%	83.44%
Total			114,000	100.0%	100.00%

Witness: L. Lawler

SEC INTERROGATORY #146

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1. P. 72] Please identify all of Priority 1 risks listed in the 2012 Asset Plan in respect of which the Applicant has, as of November 1, 2013, a) completed, or b) commenced, initiatives to remove or reduce those risks.

RESPONSE

Priority 1	Mitigation
Cast Iron	Completed
Field Applied Coating on Tie-In to Steel	A study has been initiated to understand this risk and the most effective mitigation; ongoing
Corrosion of segment of the 20-inch Lakeshore Line	A study has been initiated to understand this risk and the most effective mitigation; ongoing
Don River Bridge Crossing	A study has been initiated to understand this risk and the most effective mitigation; ongoing
Failure of Gate Station Components	Continued programs associated with Gate Station Equipment Replacement, see Exhibit B2, Tab 5, Schedule 4, Attachment 1
Failure of District Station Components	Continued programs associated with District Station Equipment Replacement, see Exhibit B2, Tab 5, Schedule 4, Attachment 2
Failure of LP Station Components	A study has been initiated to understand this risk and the most effective mitigation; ongoing. See Exhibit B2, Tab 5, Schedule 4, Attachment 3
Isolation Valves	Study commencing in 2014

Witness: L. Lawler

Main Line Valves	A study has been initiated to understand this risk and the most effective mitigation; ongoing. See Exhibit B2, Tab 5, Schedule 4, Attachment 5
Load Shed Zones	Program has been initiated and is defined in Exhibit B2, Tab 5, Schedule 2, Attachment 3
Corrosion downstream of AMP Fittings	A study has been conducted to determine failure rates, and a replacement program has been designed and implemented. See Exhibit B2, Tab 5, Schedule 3, Attachment 2
Mainline Compression Couplings	Initiated the Compression Coupling Program identified in Exhibit B2, Tab 5, Schedule 2, Attachment 2
Compression Outlet Service Tees	Conducted a study to determine failure rates, and currently designing a mitigation program. See Exhibit B2, Tab 5, Schedule 3, Attachment 3
Records Integrity	The Distribution Records Management ("DRM") program is a broad set of initiatives to enhance the asset records management practices – standards, processes, technologies, and governance required to manage an asset record throughout its lifecycle. See Exhibit B2, Tab 5, Schedule 5, Attachment 2
Cross Bores	The Sewer Safety Program was initiated in 2010 to address the risks associated with cross bores. The details are discussed in Exhibit B2, Tab 5, Schedule 3, Attachment 4
Meter Barriers	Meter Barriers are included in EGD's general construction and maintenance practices.

SEC INTERROGATORY #147

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, pp. 73-4] Please provide the current list of risks that have been assigned Priority 4.

RESPONSE

Encased bridge crossings were the only risk assigned to Priority 4.

The risk identification process identified the issues of concern to the Company's Subject Matter Advisors. Subject Matter Advisors were not asked to and generally did not identify priority 4 risks. Priority 4 risks, by definition, are those for which the likelihood is rare and/or the consequence is minor. The product of this rare likelihood and minor consequence for issues, results in risks that are of very low priority.

Witness: L. Lawler

SEC INTERROGATORY #148

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, pp. 75-80] With respect to the list of initiatives to address risks:

- a. Please identify which of these initiatives are new since the 2012 Asset Plan.
- b. Please identify which initiatives in the 2012 Asset Plan have been i) dropped, or ii) completed. For any that have been dropped, please explain why.
- c. Please identify which initiatives in the 2012 Asset Plan have been materially expanded or altered, and explain why.
- d. Please identify which of these initiatives were in existence in 2011 or earlier.

RESPONSE

- a. The following initiatives were added to the 2013 Asset Plan
 - Isolated Steel Main CP Study
 - AC Mitigation Program
 - Pipeline Markers
 - Replacement Mains (Vintage plastic and steel)
 - Meter Box Remediation Study
 - Pressure Class Isolation Valve Study and Program
 - Bare Steel Drip Program
 - Tap-n-Valve Tee
 - Load Shed Planning
 - Station Supply Reliability Study

Witness: L. Lawler

- b. The following initiatives in the 2012 Asset plan have either been completed or dropped:

Initiative	Status	Reason
Cast Iron Replacement Program	Completed	
Bare Steel Replacement Program	Completed	
Steel Tubing Service Replacement	Combined with Service relays	
Expansion Joint Study	Dropped	Managed in the Bridge Crossing Inspection program

- c. The following 2012 initiatives have been expanded or altered:

Initiative Name	Reason
Isolated Steel Study	Altered: Study has been completed and consolidated with <i>Service Relays</i> initiative. A consolidated initiative provides an effective prioritization to relay services.
Copper Service Replacement	
Compression Outlet Service Tee	Expanded to include a longer term mitigation program.
Punch Tee Cap Study	Altered: Includes a study only to understand the condition of this asset. The longer term program was removed and will be managed through maintenance programs
District Station Equipment Replacement	Expanded: To include the following assets: header station, multi cut regulators and PSI delivery stations. These assets have similar parts and require similar maintenance procedures.
Gate Station Equipment Replacement	Altered: To include the following assets: feeder station, heating systems, odorant and SCADA/telemetry. These assets are part of Gate Station equipment replacement but the risks/ issues are different between the assets; hence the original asset is branched out to the assets mentioned above. This allows for better understanding of the assets individually.
LP Delivery Sales Stations	Altered: includes a study to determine the condition of the assets in order to design a targeted mitigation program.
Meter Barrier Study & Program	Altered: Installation reflected in the construction and maintenance procedures.

Witness: L. Lawler

d. The following initiatives existed in 2011 or earlier:

- ILI and Assessment program
- Pipeline Markers
- Replacement Mains (cast iron & misc.)
- Service Relays
- Isolated Steel Mains
- District/Header Equipment Replacement
- Gate and District Station Upgrades
- Inside Regulator Replacement
- Meter Replacement Program
- Sewer Safety Program
- AC Mitigation

Witness: L. Lawler

SEC INTERROGATORY #149

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 84] Please confirm that, for the ten year period 2012 through 2021, Chart 9 forecasts system integrity & reliability direct capital of \$1,628.477 million. Please confirm that the 2012 Asset Plan, for the same period, forecast system integrity & reliability direct capital of \$1,115.274 million. With respect to this data:

- a. Please explain the primary reasons for the 46.0% increase in the system integrity & reliability direct capital forecast over that period.
- b. Please advise whether it is correct to conclude that the Applicant is proposing a permanent increase in the annual system integrity & reliability direct capital, from a level of \$70-\$80 million per year prior to 2010, to a level in excess of \$190-\$210 million per year after 2017.
- c. Please provide all studies, reports or other documents in the possession of the Applicant reviewing the system integrity & reliability capital spending of other gas distributors, including any such documents that show a similar permanent increase in capital spending in those categories.

RESPONSE

The integrity and reliability direct capital forecast for the ten year period 2012 through 2021 is estimated to be \$1,628.477 million, as stated in Chart 9 of the pre-filed evidence Exhibit B2, Tab 10, Schedule 1, page 84. Also, the forecast system integrity & reliability direct capital for the same period is \$1,115.274 million, as stated in the 2012 Asset Plan.

- a. The key drivers of the increase in capital spending in respect of system integrity and reliability over the 2012 through 2021 period are as follows:
 - (i) Maximum Operating Pressure ("MOP") Verification Program
The MOP Verification Program involves the comprehensive analysis of records and field investigation in order to verify the MOP of Enbridge's

Witness: L. Lawler

highest pressure pipelines. In 2012, Enbridge conducted the first phase of the MOP verification project on approximately 500 km of its highest pressure pipelines. This phase resulted in a verification of the MOP of these pipelines and also identified follow up issues resulting in field investigation, pipeline remediation and mitigation measures. These findings confirmed to Enbridge that it is prudent to move beyond the first phase and continue with a broader MOP verification program of its approximately 3500 km of Extra-High Pressure ("XHP") pipelines.

(ii) In-Line Inspection ("ILI") & Assessment Program:

The ILI & Assessment Program involves conducting pipeline retrofits, conducting direct assessments as required by the cyclical nature of this program, and remediating any potentially hazardous defects for all pipelines operating above 30% Specified Minimum Yield Strength ("SMYS") and selected pipelines operating between 20% and 30% SMYS.

(iii) AMP Fitting Replacement Program:

A 30% annual increase in detected and reported leaks related to AMP Fittings was experienced between 2007 and 2012. In 2013, EGDI conducted an analysis on the failure mechanism and determined the forecasted AMP leak profile as shown in Figure 1 of the pre-filed evidence found at Exhibit B2, Tab 5, Schedule 3, Attachment 2. The optimized replacement program was developed taking into consideration the level of risk associated with the number of leaks required to be managed, capacity for emergency response early in the program, capacity to perform the replacement efforts early in the program, and program cost. This replacement rate profile is shown in Figure 7 of the pre-filed evidence.

(iv) Gate Stations:

The increase in capital requirement to this historical on-going program is attributable to a number of factors as follows:

- Regulatory compliance as outlined in the prefiled evidence at Exhibit B2. Tab 5, Schedule 1, on pages 4 and 5 which requires EGDI to implement a Process Hazard Analysis approach to managing station

risks, and implementing security measures to monitor the site and control access.

- Work driven by safety and system reliability, associated with age and obsolescence to ensure that assets are replaced before failures occur.
- Increasing station throughput due to growth.

The evidence associated with this spend is in pre-filed evidence at Exhibit B2, Tab 5, Schedule 4, Attachment 1.

EGDI continues to prudently balance capital requirements and efficiencies while minimizing the impact on the rate payer when developing its gate station upgrade program.

(v) District and Sales Station Replacement Program:

The District and Sales Station Replacement Program involves work ranging from station component replacement, such as electronic data collectors, to complete station replacement. The replacement of district and sales stations is a historical on-going program driven by system integrity and reliability requirements and growth. The incremental efforts in this program are associated with the increased focus on reducing risk through data analysis and aging assets in compliance with regulatory requirements identified in the pre-filed evidence found at Exhibit B2, Tab 5, Schedule 1, on pages 4 and 5. This approach seeks to prudently balance capital investment and risk impact, while minimizing impact to rate payers.

The evidence associated with this spend is in the pre-filed evidence at Exhibit B2, Tab 5, Schedule 4, Attachment 2

- b. It is correct that EGDI is forecasting a level of approximately \$190 to \$210 million per year after 2017 for system integrity & reliability direct capital.
- c. EGDI does not have any such reports, studies, or documents that review the system integrity and reliability capital spending of other gas distributors.

SEC INTERROGATORY #150

INTERROGATORY

Issue E48: Is Enbridge's updated asset plan appropriate?

[B2/10/1, p. 89] Please confirm that, for the ten year period 2012 through 2021, Chart 10 forecasts relocations direct capital of \$109.383 million. Please confirm that the 2012 Asset Plan, for the same period, forecast relocations direct capital of \$109.383 million. With respect to this data:

- a. Please explain the primary reasons for the 14.5% decrease in the relocations direct capital forecast over that period.
- b. Please explain why the average annual forecast in this category is more than double the historical period.

RESPONSE

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
2012 Asset Plan	\$12,350	\$13,209	\$15,035	\$15,150	\$15,259	\$11,400	\$11,400	\$11,400	\$11,400	\$11,400	\$128,003
2013 Asset Plan	\$5,186	\$14,000	\$14,280	\$12,485	\$12,734	\$9,742	\$9,937	\$10,135	\$10,338	\$10,545	\$109,382
Variance	\$7,164	(\$791)	\$755	\$2,665	\$2,525	\$1,658	\$1,463	\$1,265	\$1,062	\$855	\$18,621

For the period of 2012 to 2021, the 2012 Asset Plan shows relocation direct capital of \$128.003 million compared with the 2013 Asset Plan of approximately \$109.383 million.

- a. The Asset Plan is created at a point in time, and the forecasts are identified from the knowledge of the program at that specific time. The intent of the Asset Plan is to be directional with respect to the requirements of the assets, and to inform the budget, but is not a final budgetary document. As such, there may be discrepancies between the capital dollars identified in the Asset Plan and the final capital budget.

The 14.5% decrease from the 2012 Asset plan is attributed to the following:

Witnesses: L. Lawler
T. MacLean

1. The actual spend in 2012 was approximately \$7.164 M below the forecast, as the work associated with transit projects did not transpire in the time frame expected.
 2. As detailed municipal and transit plans become available, the Company refined the forecast further. This information yielded a reduction in overall Relocation spend. However, this trend could potentially change as new information becomes available.
- b. Relocation projects are driven by external groups conducting significant works initiatives that impact gas distribution assets. The relocation forecast is higher than historic expenditures due to the significant increase in transit projects, municipal growth, infrastructure rehabilitation, and specialty infrastructure work, such as that associated with the Pan Am games, projected to occur over the next 10 to 15 years. This is explained at Exhibit B2, Tab 4, Schedule 1.

Witnesses: L. Lawler
T. MacLean