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Energy Futures Supplement

DEMAND SENSITIVITIES



AN ENERGY MARKET ASSESSMENT

Canada



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ENERGY FUTURES SUPPLEMENT: DEMAND SENSITIVITIES

Energy Futures Supplement (EFS) is a companion publication to the National Energy Board's *Energy Futures* series of long-term Canadian energy supply and demand outlooks. EFS compliments the *Energy Futures* projections by exploring additional areas of long-term interest for Canada's energy system.

The central projection of the Board's *Energy Futures* series is the Reference Case.¹ A Reference Case includes baseline projections based on the assumed macroeconomic outlook and energy prices, and government policies and programs that were law or near-law at the time the report was prepared. The Board also explores alternative possibilities in its sensitivity cases and alternate scenarios. These cases change key assumptions that impact several elements of the energy system, such as price, economic growth, policies and programs, and geopolitical conditions.²

EFS: Demand Sensitivities develops additional sensitivity cases that focus on several sector-specific areas related to Canadian energy use. These cases differ from the broader sensitivities covered in the *Energy Futures* publications, such as the High and Low Price Cases presented in *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035* (EF 2013), which impact energy supply and demand across the Canadian energy system.

An important characteristic of energy demand is that it is a derived demand. This means that energy users do not demand energy for its own sake, but rather for the services it provides (such as driving a car, heating a home, or running equipment). The amount and type of energy that is used depends on the demand for these services and also the energy-using technology used to provide them. The sensitivity cases in *EFS: Demand Sensitivities* change specific assumptions related to the demand for services and the technological characteristics, such as energy efficiency and fuel type. Aside from these changes, all other assumptions and key drivers are kept at Reference Case levels.

Three general topics are covered in *EFS: Demand Sensitivities*:

1. Transportation demand and demographic trends
2. Long-term uncertainties in natural gas use
3. Powering Liquefied Natural Gas (LNG): Alternative Options

Questions, feedback, and ideas for future analysis can be sent to us at: EnergyFutures@neb-one.gc.ca

1 The most recent *Energy Futures* outlook is *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035* (EF 2013) which was released November 2013.

2 More specifically, scenarios, such as those featured in the [2007 Energy Futures](#) report, are self-contained stories about how the future could unfold. In a scenario, all the key assumptions are subject to change. Sensitivity analysis, featured in this and all [subsequent Energy Futures reports](#), explore how energy outcomes could change based on changes in key assumptions. The impact of changing these assumptions is measured by their difference from the Reference Case.

1. TRANSPORT DEMAND AND DEMOGRAPHIC TRENDS

Issue and Background

Changing population and demographic trends are expected to have an impact on future economic and energy use trends. This appears to be particularly true for the case of transportation, as was highlighted in the Energy Context section of EF 2013. Using the available Canadian data³, Figure 1 illustrates several key trends in population and transportation by comparing driving-age people under 45 as well as 45 and older.

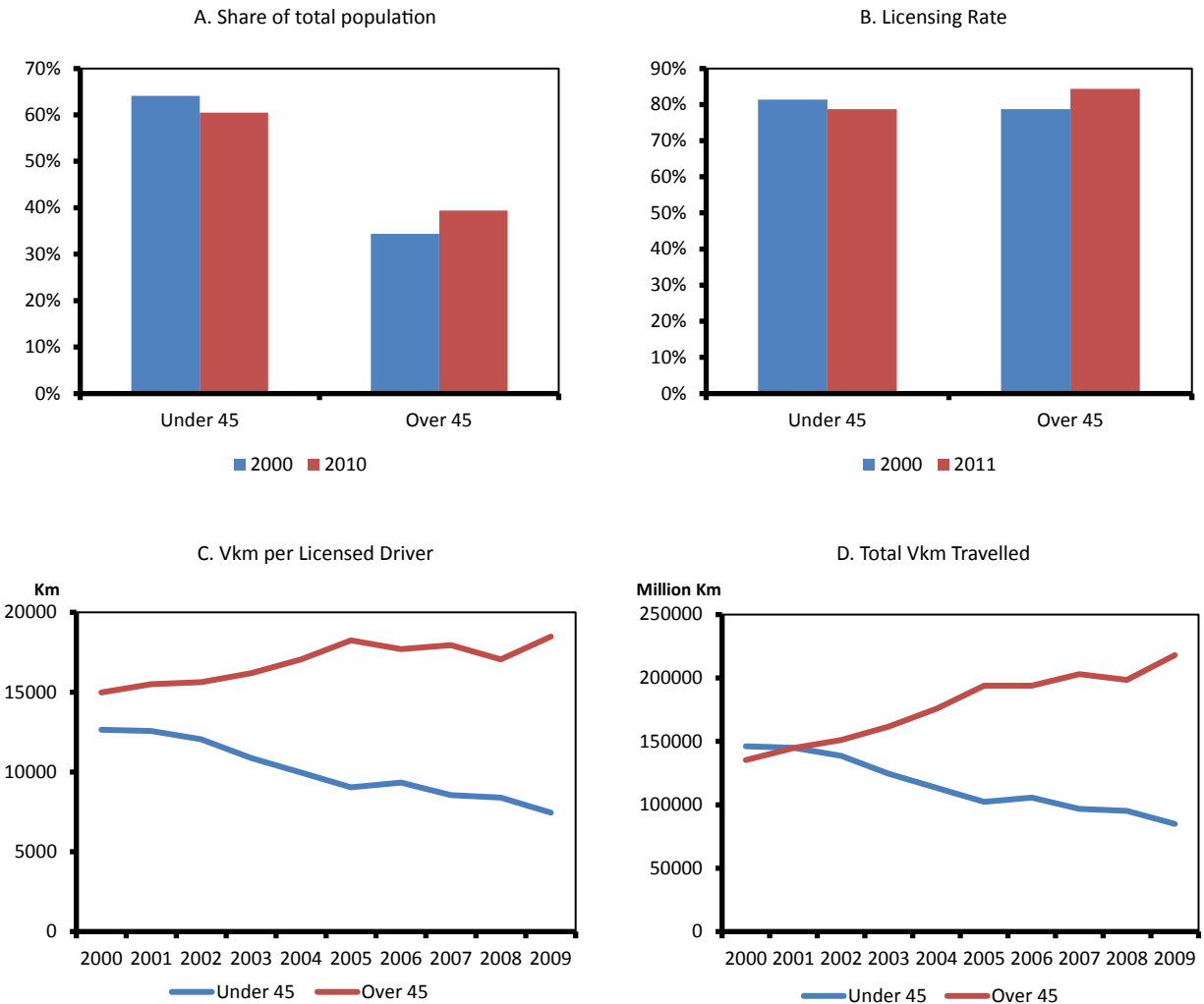
These charts illustrate several trends in Canadian demographics and transport demand over recent history:

1. Older age groups are becoming a larger share of the population.
2. The licensing rate, which is the share of a given age group population with a driver's licence, is declining for younger age groups and increasing for older age groups.
3. Of those people that do have a driver's licence, younger drivers are driving less, while older drivers are driving more.
4. As a result, total vehicle km (VKm) travelled by drivers in the younger age group fell over the period, and increased in the older age group.

3 Vehicle travel data by age group comes from Statistics Canada's *Canadian Vehicle Survey*, which was published between 2000 and 2009 (CANSIM table 405-0070). Since the *Canadian Vehicle Survey* data is estimated based on a sample population, each data point has an associated coefficient of variation which can be used to assess data quality and inferences made based on that data. Data on the number of licensed drivers comes from Transport Canada's document *Canadian Motor Vehicle Traffic Collision Statistics*, the latest edition available is for the year 2012.

FIGURE 1

Transportation and Demographic Trends by Age Group



Source: Statistics Canada, Transport Canada, NEB

Overall, total Vkm travelled by personal vehicles increased by approximately 20 billion Km from 2000 to 2009. A statistical method called factorization analysis provides a way to analyse the relative impact of the changing trends shown in Figure 1 on total Vkm travelled. This type of analysis is used by Natural Resources Canada in their [Energy Efficiency Trends Analysis](#) work as a way to separate the impact of activity, structural and intensity effects on energy use. Figure 2 applies this technique to VKm and demographic trends⁴. In this case the change in total Vkm travelled relative to 2000 (dashed black line) is broken down into four effects: Population Effect, Demographic Structure Effect, Licensing Rate Effect, and Driving Intensity Effect. The sum of these four effects adds up to the total change in VKm in any given year.

4 Specifically, the decomposition methodology is Log-Mean Divisia Index I (LMDI I). The Natural Resources Canada methodology is described in the report prepared by M. K. Jaccard and Associates for the Office of Energy Efficiency, *Improvement of the OEE/DPAD Decomposition Methodology*, 2005. This report is available by request from the Office of Energy Efficiency. Also see B.W. Ang, *A Simple Guide to LMDI Decomposition Analysis*, available [here](#).

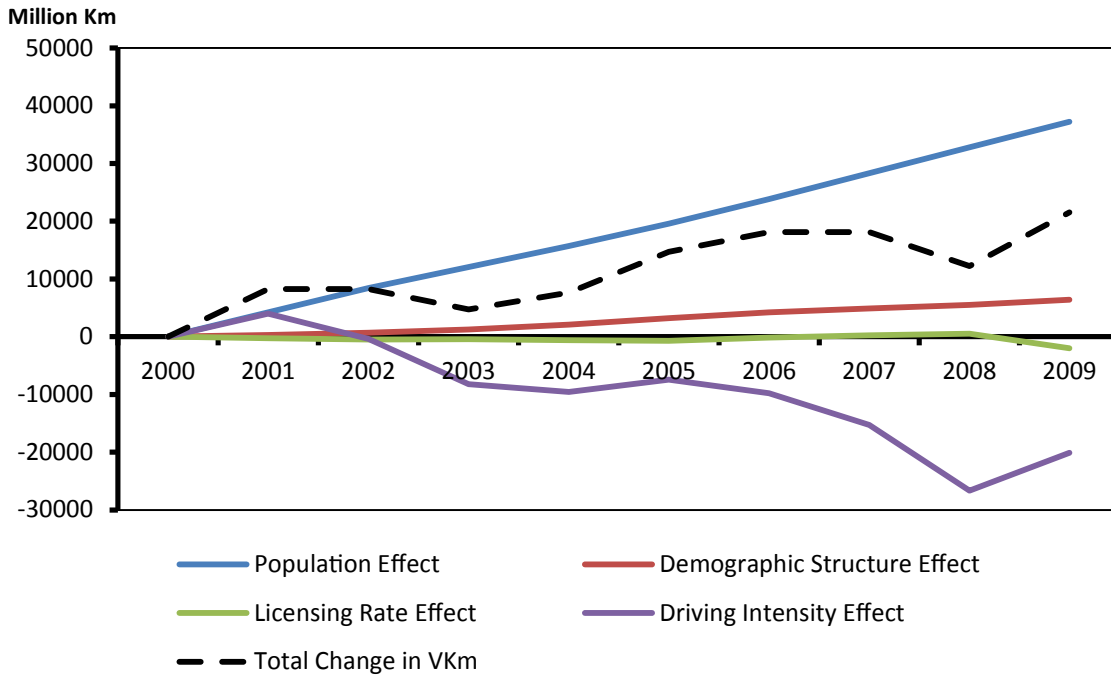
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- **Population Effect:** the impact of overall driving-age population growth over the time period. Population increased steadily over this period, so there is an increase of the driving age population which leads to upward pressure on the total VKm travelled.
 - **Demographic Structure Effect:** the impact of the changing age structure of the population. Older age groups increased their share of the population over this period. Since older age groups tended to drive more, the aging of the population leads to further upward pressure on total VKm travelled.
 - **Licensing Rate Effect:** the impact of the changing share of licensed drivers within a given age group. As Figure 2 shows, this impact had a small effect over the period, suggesting the impact of a decreasing licensing rate among younger generations is offset by an increasing licensing rate among older generations.
 - **Driving Intensity Effect:** the impact of changes in how much licensed drivers actually drive. This is the key effect reducing overall driving activity. Although Figure 1 shows that licensed drivers from older age groups drive more over this period, on an aggregate level, the decline in driving activity among younger drivers has a bigger impact.

Figure 2 highlights the importance of demographic trends in driving behavior and the significant impact that reduced driving by younger age groups is having on overall transport activity. There is a growing body of research devoted to unravelling these trends further, although much of it focuses on similar trends in the United States (U.S.)⁵ Explanations for these changing patterns are varied and include: the impact of rising costs (including fuel, purchase, maintenance and insurance), changing income and employment trends, socioeconomic and cultural factors, and changing technology.

5 See, for example, slides from a session devoted to the topic at the [2014 EIA Conference](#) and the [Issues in Focus](#) on the topic from the Energy Information Administration's (EIA) 2014 [Annual Energy Outlook](#) (AEO), and recent research from the [University of Michigan Transportation Research Institute](#).

FIGURE 2

Change in VKm Relative to 2000, Decomposed into Four Effects



Sensitivity Analysis

Given this uncertainty, two sensitivity cases are created to explore the potential future impacts of these trends on energy use:

- High VKm Case: trends of increased driving intensity and licensing rates from the older age groups continue, while the decreasing trends from younger age groups flatten and/or reverse.
- Low VKm Case: trends of decreasing driving intensity and licensing rates from the younger age groups continue, while the increasing trends from older age groups flatten and/or reverse.

Table 1 shows the average annual growth rate for VKm in personal vehicles and passenger energy use over the projection period. Energy prices, population trends (including overall growth and demographic structure), and other macroeconomic variables remain at the Reference Case levels.

TABLE 1

VKm and Energy Use by Case

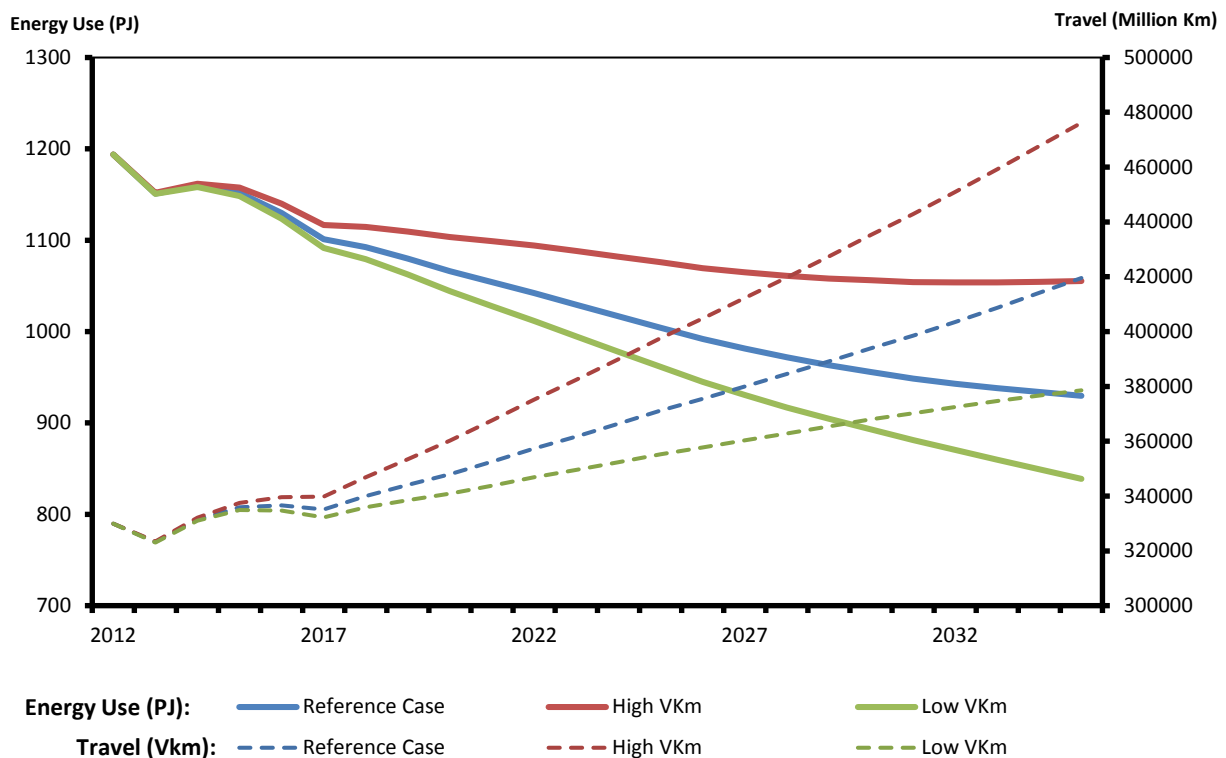
	VKm in Personal Vehicles, Average Annual Growth, 2012-2035 (per cent)	Passenger Energy Use, Average Annual Growth, 2012-2035 (per cent)
Reference Case	1.0	-1.0
High VKm Case	1.6	-0.5
Low VKm Case	0.5	-1.5

Figure 3 compares VKm travelled in personal vehicles (dashed lines) and passenger sector⁶ energy use (solid lines) in the Reference Case to the High and Low VKm Cases. Passenger energy use, measured in petajoules (PJ) continues to decline in all of the sensitivity cases. This highlights the impact of the efficiency improvement in passenger vehicles that is expected over the projection period.⁷ In the High VKm Case, passenger energy use declines at an average annual rate of 0.8 per cent, or approximately 17 per cent over the projection period. In the Low VKm Case, passenger energy use declines by an average of 1.8 per cent per year, nearly 35 per cent over the 2012-2035 projection period.

By 2035, passenger energy use is 13 per cent higher than the Reference Case in the High VKm Case, and 10 per cent lower than the Reference Case in the Low VKm Case.

FIGURE 3

Passenger Energy Use (Excluding Aviation) and VKm Travelled, Reference Case and Sensitivities



6 Excludes aviation fuel use.

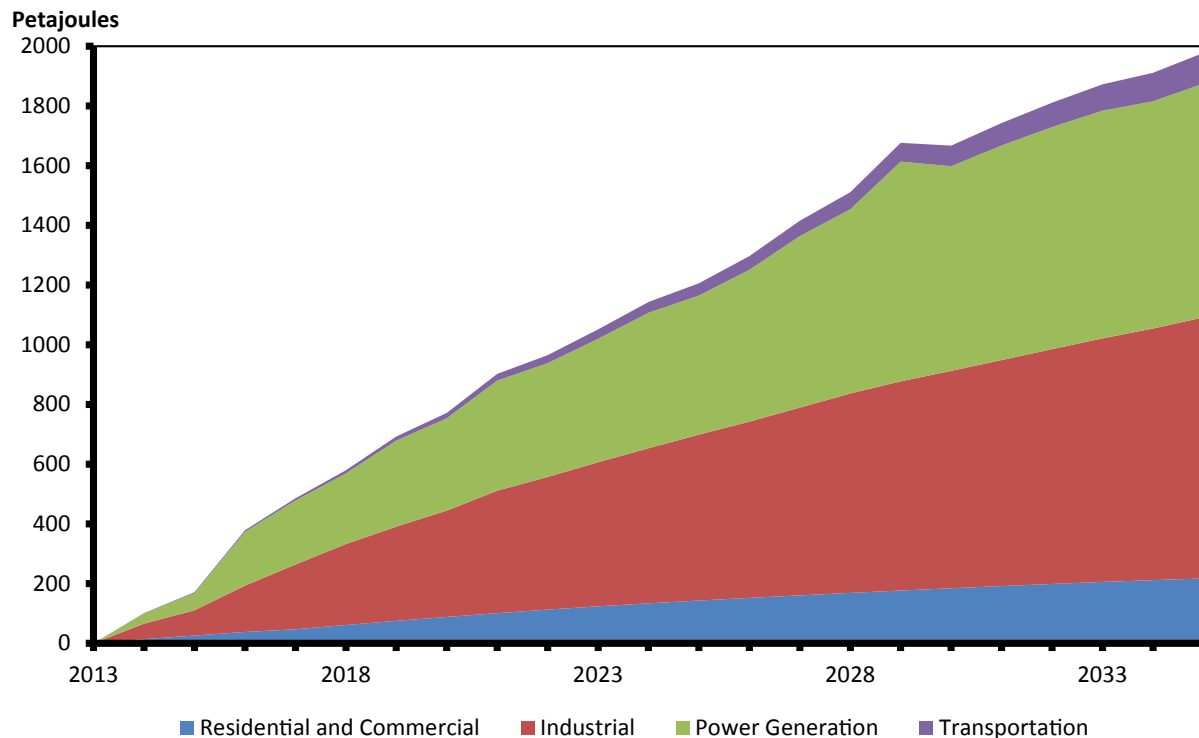
7 Efficiency improvements in the three cases are approximately the same, with litres per 100 VKm declining nearly 40 per cent over the projection period, from nine litres/100 km in 2013 (or 25 miles per gallon) to six litres/100 km in 2035 (or 40 miles per gallon).

2. LONG-TERM UNCERTAINTIES IN NATURAL GAS USE

EF 2013 projects natural gas to be the fastest growing fuel in Canadian primary demand over the projection period. Figure 4 shows the growth in natural gas primary demand relative to 2013 by sector. Overall, primary natural gas demand increases by an average annual rate of 1.7 per cent (approximately 1 900 PJ or 5 billion cubic feet per day (Bcf/d)) from 2012 to 2035. The projected growth in natural gas use is dominated by increases in power generation and industrial use. The power generation demand growth is driven by retiring coal units, as well as meeting increasing demands for electricity. Key drivers of the industrial growth include use by natural resource industries, such as oil sands and other energy-intensive industries. The growth in transportation use is notable as well: although it is a fairly small share, the use of natural gas in transportation increases from one PJ in 2012 to over 100 PJ in 2035.

FIGURE 4

EF 2013 Reference Case Growth in Primary Natural Gas Demand 2012-2035, by Sector



To explore this trend further, additional sensitivity cases are created to analyze the impact of alternative assumptions related to oil sands and power generation natural gas use and the potential for an even greater increase in transportation demand.

2.1 Natural Gas in Transportation

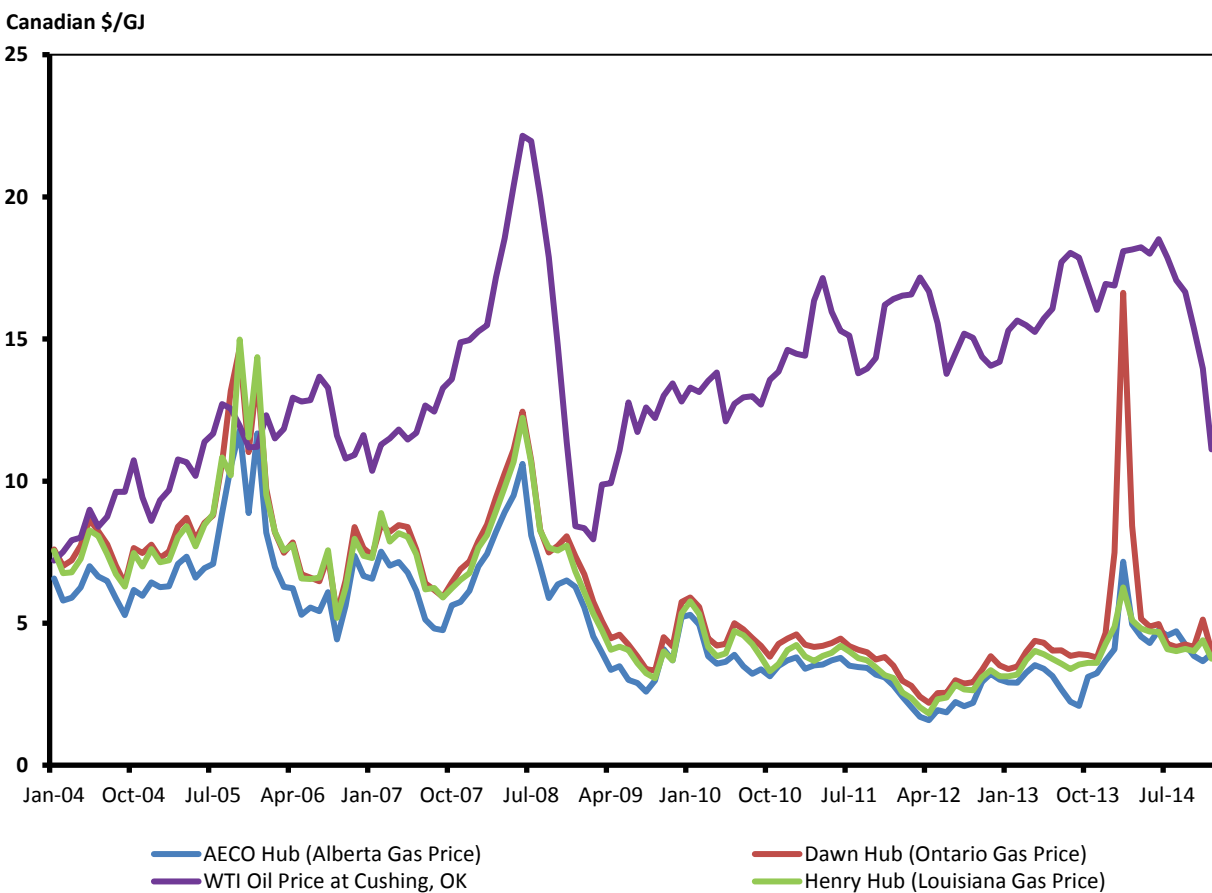
Issue and Background

In recent years, there has been interest in capitalizing on the price differential between crude oil and natural gas (Figure 5) by substituting natural gas for oil products. The transportation sector uses the majority of liquid fuels in the U.S. and Canada, representing a target for oil-to-natural gas substitution.

Much of the interest in natural gas as a transportation fuel is for medium and heavy duty freight trucks. As noted in EF 2013, this interest is primarily in operations where the vehicles return to central locations often and use regional transport corridors. Several fueling stations are in place or are currently being constructed in key strategic highway locations. An emerging area of interest is using natural gas as a fuel for rail freight transport.

FIGURE 5

Crude oil and Natural Gas Price on an Energy Equivalent Basis, Monthly, 2004 to 2014



Source: GLJ

There are a variety of additional costs and uncertainties with switching from crude oil to natural gas. The capital cost of incremental natural gas vehicles (NGVs) and locomotives are higher than their diesel counterparts.^{8,9} There are a variety of infrastructure concerns, particularly related to refueling. Also, the persistency of the differential is uncertain and can be volatile, particularly with the recent natural gas price increases in winter 2013 and the recent declines in oil prices (Figure 5).

Sensitivity Analysis

The EF 2013 demand projections included a modest penetration of natural gas in the freight transportation sector. To explore the impact of additional natural gas use for freight transportation, two additional sensitivity cases are created. These sensitivity cases are:

- The High NGV Case: assumes a higher penetration rate of medium and heavy duty natural gas powered freight trucks than in the Reference Case.
- High NGV+Rail Case: penetration of NGV trucks consistent with the High NGV Case, combined with a high penetration of natural gas-powered locomotives in rail freight transportation.

There are two options in using natural gas for vehicles: compressed natural gas (CNG) and liquefied natural gas (LNG). Due to the size constraints imposed on CNG fuel tanks resulting from CNG's high diesel gallon equivalency (DGE)¹⁰, it is most suited for short-haul applications and is assumed to be adopted only by medium duty vehicles (MDVs). With a lower DGE and a shorter shelf-life,¹¹ LNG can handle larger amounts of fuel for both long-hauls and other applications that require constant fuel use. LNG is therefore assumed to be adopted by heavy duty vehicles (HDVs) and train locomotives.

8 There is not a consensus on what the incremental cost of a NGV actually is: it depends on the engine chosen, the number of tanks installed, the vehicle's application and the original equipment manufacturer of the vehicle. Recent incremental estimates for medium and heavy duty vehicles have ranged between US \$20 000 and US \$70 000 (Source: Work Truck Magazine; Fuel Space). Higher costs are generally associated with larger storage volumes.

9 The incremental cost for an LNG-capable locomotive is currently about US \$100 000 (EIA)

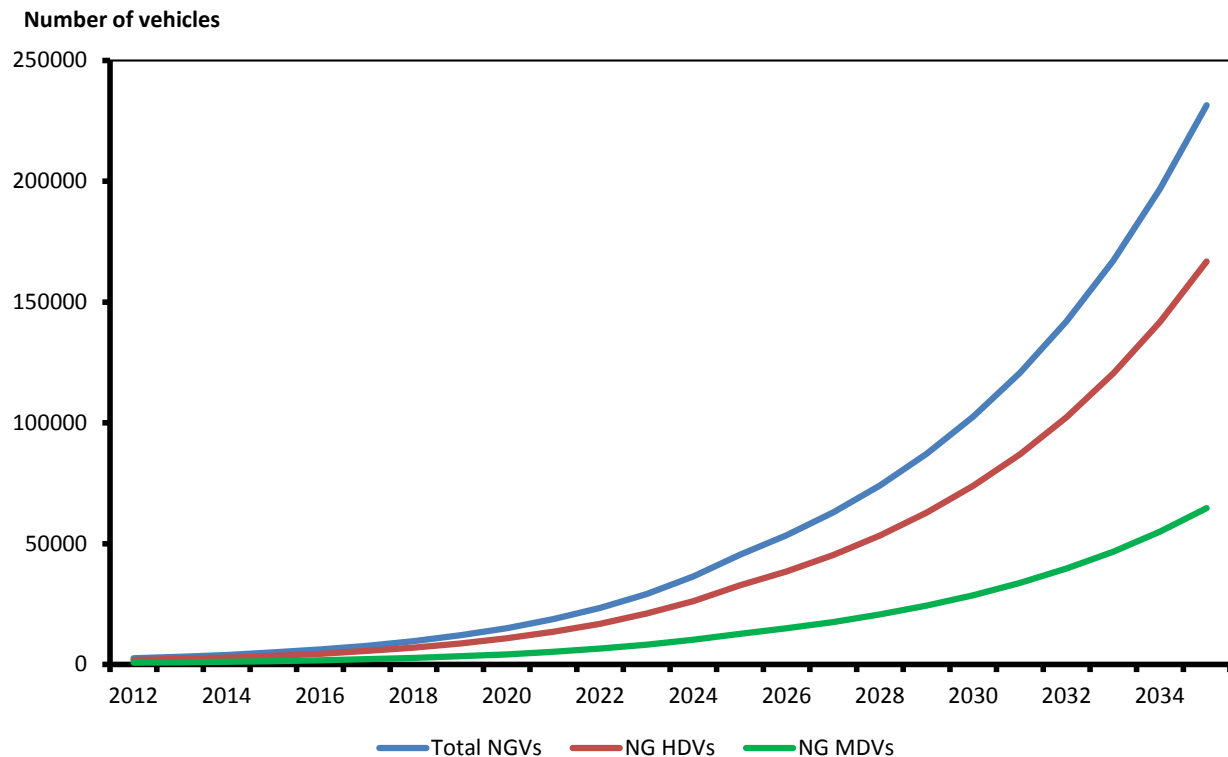
10 Diesel gallon equivalency is the volume needed to contain the same energy in a gallon of diesel.

11 Once in the fuel tank, LNG must be used within 5-7 days or it starts to vent from the tank.

In the High NGV Case, NGV adoption targets are created based on the Energy Information Administration's (EIA) 2012 *Issues in Focus* section of its *Annual Energy Outlook* (AEO) and other external reports.¹² The number of medium and heavy NGVs in the High NGV Case are shown in Figure 6. The number of NGVs in the High NGV Case increases to over 200 000 vehicles by 2035, while the Reference Case projection was consistent with 50 000 to 60 000 MDVs and HDVs.

FIGURE 6

Freight NGV Projection in the High NGV Case



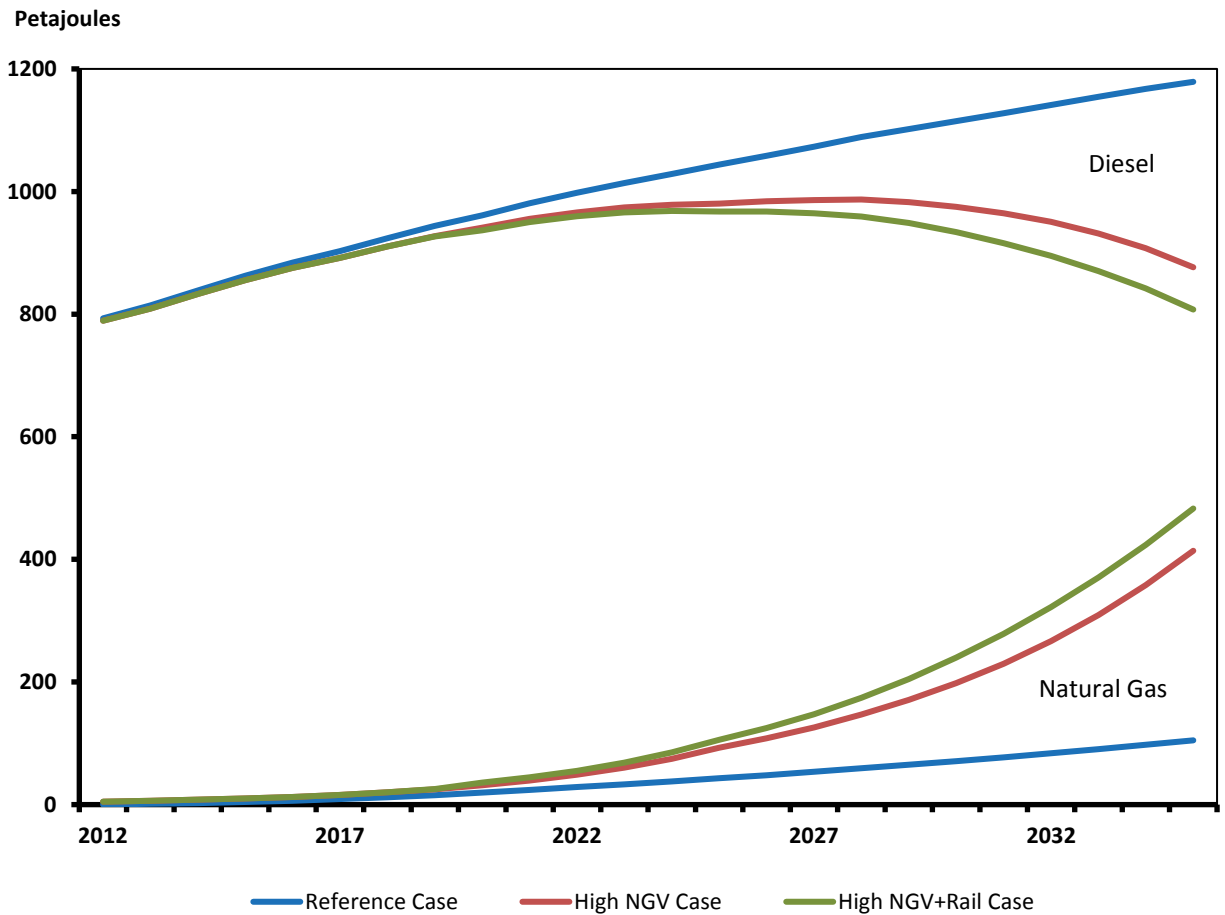
Locomotive adoption targets are based upon the 'High Rail LNG' Case from the EIA's projection in the *Issues in Focus* section of the AEO 2014. This Case involves a transformative change in the rail industry, where natural gas meets 95 per cent of freight rail energy demands by 2040 (approximately 90 per cent in 2030).

12 CERl's Report Number 134 was used to construct a freight vehicle forecast and Marbek's 2010 study for the Canadian Natural Gas Vehicles Alliance (CNGVA) helped construct a 2020 target for freight vehicles.

Figure 7 illustrates the impact that freight NGV adoption had on total freight, diesel and natural gas demand over the projection. By 2035, natural gas usage is over 300 PJ higher than its Reference Case level, while diesel use is 287 PJ lower.¹³

FIGURE 7

Freight Diesel and Natural Gas Demand by Case

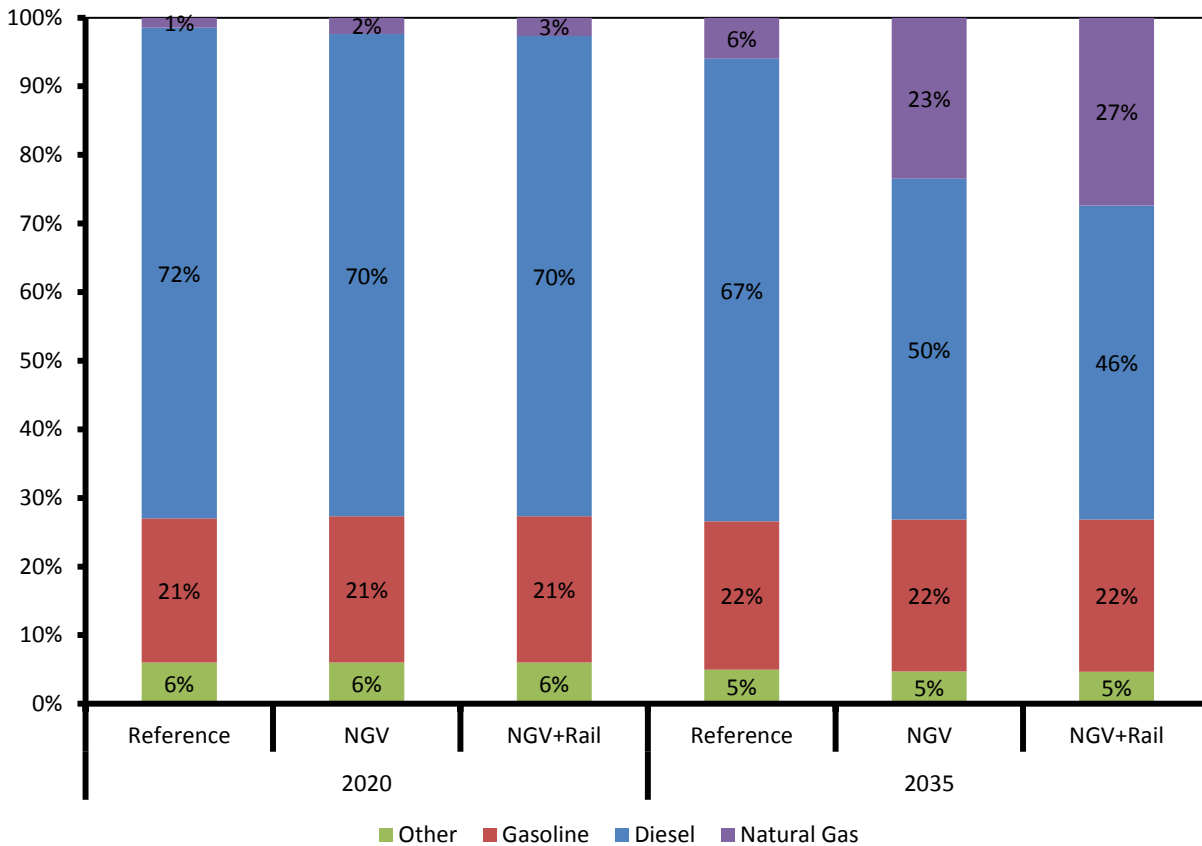


13 Overall energy use increases by approximately 40 PJ in the High NGV Case, following from the EIA's AEO2014 results that show a higher efficiency improvement for diesel freight trucks than natural gas-powered vehicles.

Figure 8 illustrates how the freight transportation (excluding air) fuel mix changes between the cases in 2020 and 2035. In 2020, the difference between the cases is limited, with the share of natural gas in the NGV+Rail Case approximately one per cent higher than in the Reference Case. This limited medium term impact illustrates the gradual nature of adopting a new technology. By 2035 the impact is larger: natural gas accounts for 23 per cent of freight demand in the NGV Case, and 27 per cent in the NGV+Rail Case, relative to just six per cent in the Reference Case. The share of diesel drops to 50 per cent in the NGV Case and 46 per cent in the NGV+Rail Case.

FIGURE 8

Share of Fuel Use in Freight Transportation by Case, 2020 and 2035



2.2 Natural Gas Intensity for Oil Sands

Issue and Background

In EF 2013, natural gas use by the oil sands is one of the key growth areas for overall energy use. Purchased natural gas requirements for the oil sands (including cogeneration) rise to 95.1 10⁶m³/d (3.4 Bcf/d) by 2035. Much of this growth is from in situ production, which EF 2013 projects to be the largest source of oil production growth over the projection period. The thermal in situ process is energy intensive, involving injecting steam into the ground to heat up the bitumen in the oil reservoir, reducing its viscosity enough to be pumped to the surface.

In situ's Steam Oil Ratio (SOR) is the ratio of the volume of steam required to produce the same volume of oil. Higher SORs are the result of more steam being used to produce a barrel of oil. Since natural gas is used to create the steam, the SOR is a measure of natural gas intensity.

There are a variety of ways to measure SOR:

- Instantaneous SOR (iSOR): iSORs are loosely defined as the SOR of a facility or reservoir at a given moment in time, which is typically measured from monthly production. iSORs are higher at initial production stages as more energy is needed to overcome some production inertia. When production becomes consistent, iSORs decline, with the rate of decline plateauing after several years. Maturing reservoirs may start to exhibit a modest iSOR increase as more effort is needed to keep up current production rates.
- Annual SORs at Project Level: ratio of a project's annual steam usage to annual bitumen production. This measure provides a useful way of comparing the annual efficiency performance of various sites across time. Figure 9 displays annual SORs for various Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD) projects from 2009 to 2013¹⁴ and illustrates the variation that exists between them. The points are scaled by the facilities' production levels, with larger circles representing higher production. Figure 9 illustrates that extreme outliers in terms of SOR (both high and low) often are producing at low levels.

FIGURE 9

Annual SORs at Project Level, 2009-2013



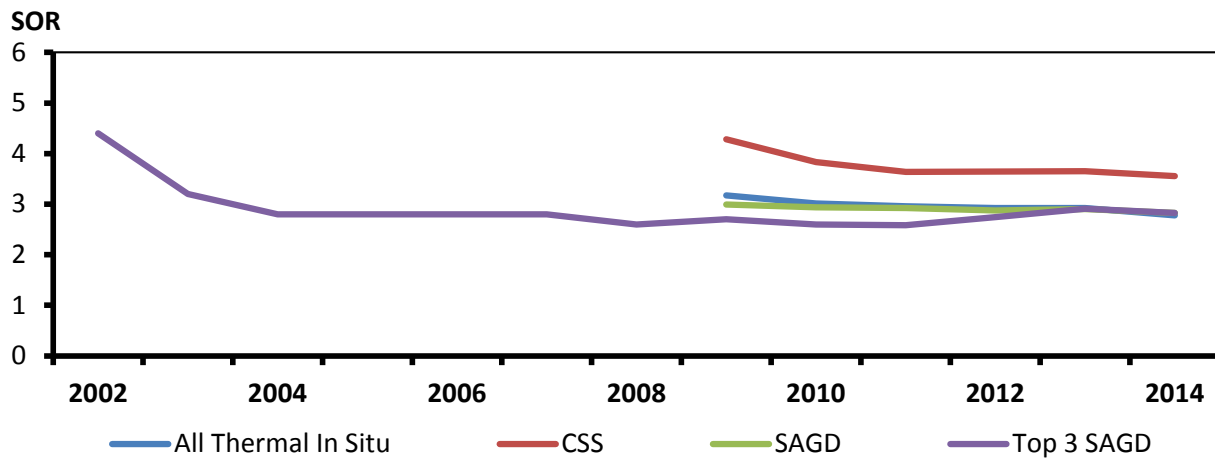
Source: AER

¹⁴ Large outliers are omitted since they are likely indicative of young reservoirs overcoming production inertia.

- Aggregate Production-Weighted SOR: ratio of the annual steam usage to annual bitumen production for the entire industry or production type. This measure is useful to compare recovery processes or measure the efficiency of in situ in general. Figure 10 presents the aggregate production-weighted SOR for CSS, SAGD and thermal in situ and shows that CSS production has a consistently higher production-weighted SOR than SAGD. Figure 9 highlights this as well, as the blue circles have most of their area located above the area of the red circles. This high-level efficiency measure provides the basis for long-term energy modeling analysis.

FIGURE 10

Historical aggregate production-weighted SOR – In Situ Projects



* Top Three SAGD producers are Foster Creek, Firebag and MacKay River, which represented a large majority of production from 2002-2008 and therefore offer a good measure of In Situ’s aggregate production-weighted SOR over that period.

Source: Alberta Energy and AER

Despite the fact that in situ’s SOR has declined since the inception of SAGD in 2002, the recent flat-line in Figure 10, as well as the volatility shown in Figure 9, is indicative of the current uncertainty regarding where energy intensity is heading. While the distribution of CSS SOR data has exhibited fairly consistent SORs over the five year period, SAGD has seen variation persist around the SOR level of three, so it is unclear where the overall values are trending.

Adding to the future uncertainty is that these charts only account for existing facilities. Much of the incremental production over the EF 2013 projection period will involve exploiting new reservoir types with methods which have unknown natural gas intensities. Recent projects have encountered increasing levels of heterogeneity¹⁵ in the reservoir rock. This has increased the steam requirements for many facilities and in turn, spurred the continuing pursuit of innovative solutions to enhance SAGD recovery and reduce the SOR. Examples of such innovations include injecting methane or solvent with steam, and drilling vertical infill wells between SAGD wells in an attempt to recover bitumen from outside of the reservoirs that have been mobilized by heat escaping from them. These, along with several other innovative processes, are currently being implemented or are in the testing phase. Work is also being done to identify an economic means of exploiting the bitumen locked in the Grosmont carbonates, with the most notable method being electromagnetic-assisted SAGD, where electrodes are inserted into wells that can target the bitumen for heating with electromagnetic radiation.

Key questions for the future include:

- Will process improvements be enough to counter the challenges of heterogeneous reservoirs?
- Given these process improvements and heterogeneous reservoirs, what will the new facility-level SORs be and to what degree will they alter in situ's aggregate production-weighted SOR?
- With in situ providing over 70 per cent of the incremental production over the EF forecast, and significant variations in SORs possible from year-to-year for a given well, what effect will a distribution of new and aging existing reservoirs have on aggregate production-weighted SORs in a given year of the projection?

Sensitivity Analysis

The EF 2013 Reference Case assumes a 0.5 per cent decrease in the SOR over the forecast period. But future efficiencies may be higher or lower, depending on the answers to the above questions. Because of the uncertainty in natural gas efficiency and the fact that in situ production is expected to be such an integral component of the projection's natural gas demand, it is worth exploring how natural gas use would change under alternative SOR assumptions.

To explore the uncertainty around in situ natural gas use and efficiency, three alternative sensitivity cases are created and compared to the Reference Case. These are:

- High SOR Case: one per cent annual increase in SOR over projection
- Constant SOR Case: constant SOR over projection
- Low SOR Case: two per cent annual decrease in SOR over projection

15 Formations are called homogeneous if the rock formations do not change significantly throughout the reservoir and heterogeneous if they exhibit significant variability in the reservoir. Homogenous sand reservoirs are more predictable to produce from and generally require less steam than heterogeneous reservoirs, which have become a focal point for enhanced recovery research.

Figure 11 illustrates how these assumptions affect the SORs over the forecast period. Although these cases vary widely, the range of the aggregate SOR values shown in Figure 11 are within the majority of facility production-weighted SOR values shown in Figure 9. It is important to note that this analysis assumes that oil sands production growth is equal to the Reference Case in the sensitivity cases. This may not hold. Higher or lower SOR values, implying higher or lower productivity and/or natural gas requirements by project, may alter project economics and impact production growth and therefore affect total oil sands natural gas requirements. This analysis ignores these dynamics in an effort to illustrate how sensitive both the oil sand requirements and the total Canadian demand for natural gas are to SOR assumptions in the EF 2013 projection.

FIGURE 11

2035 SOR Assumptions, Reference and Sensitivity Cases

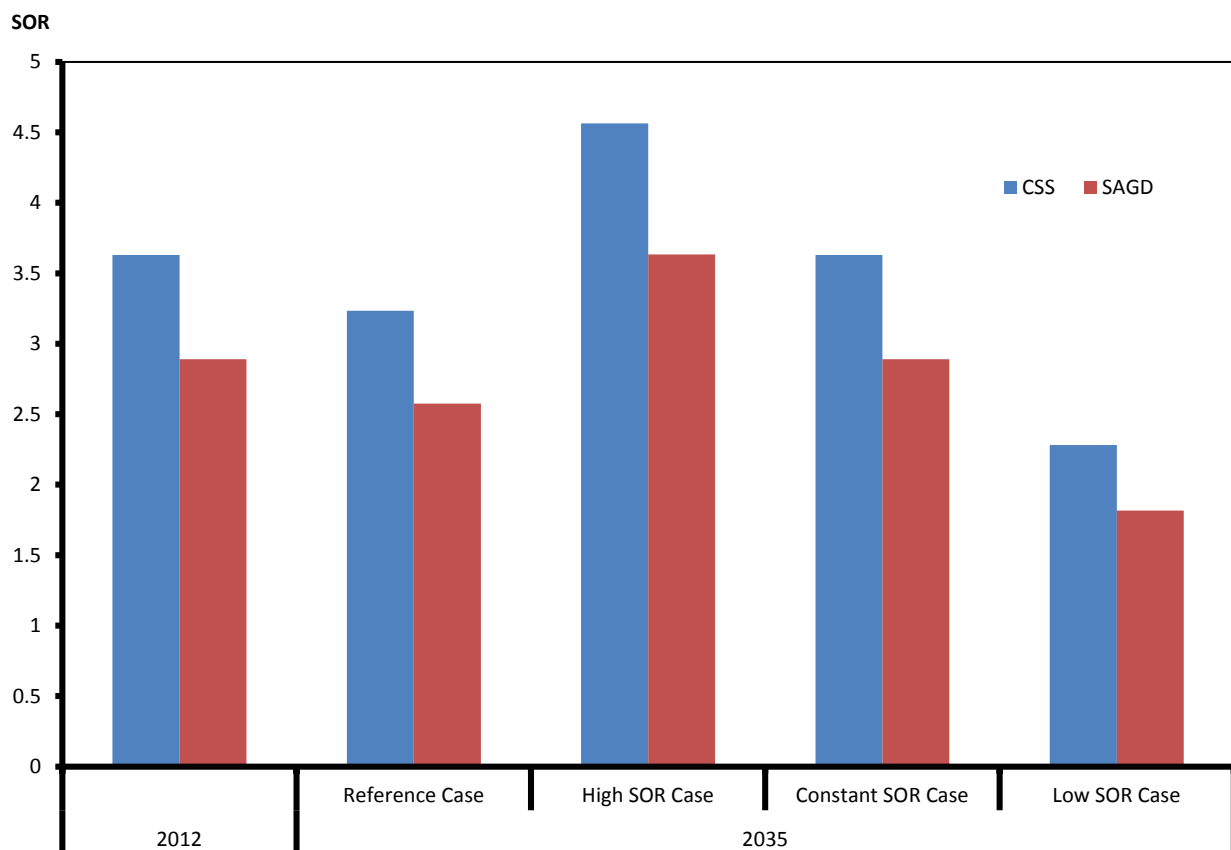


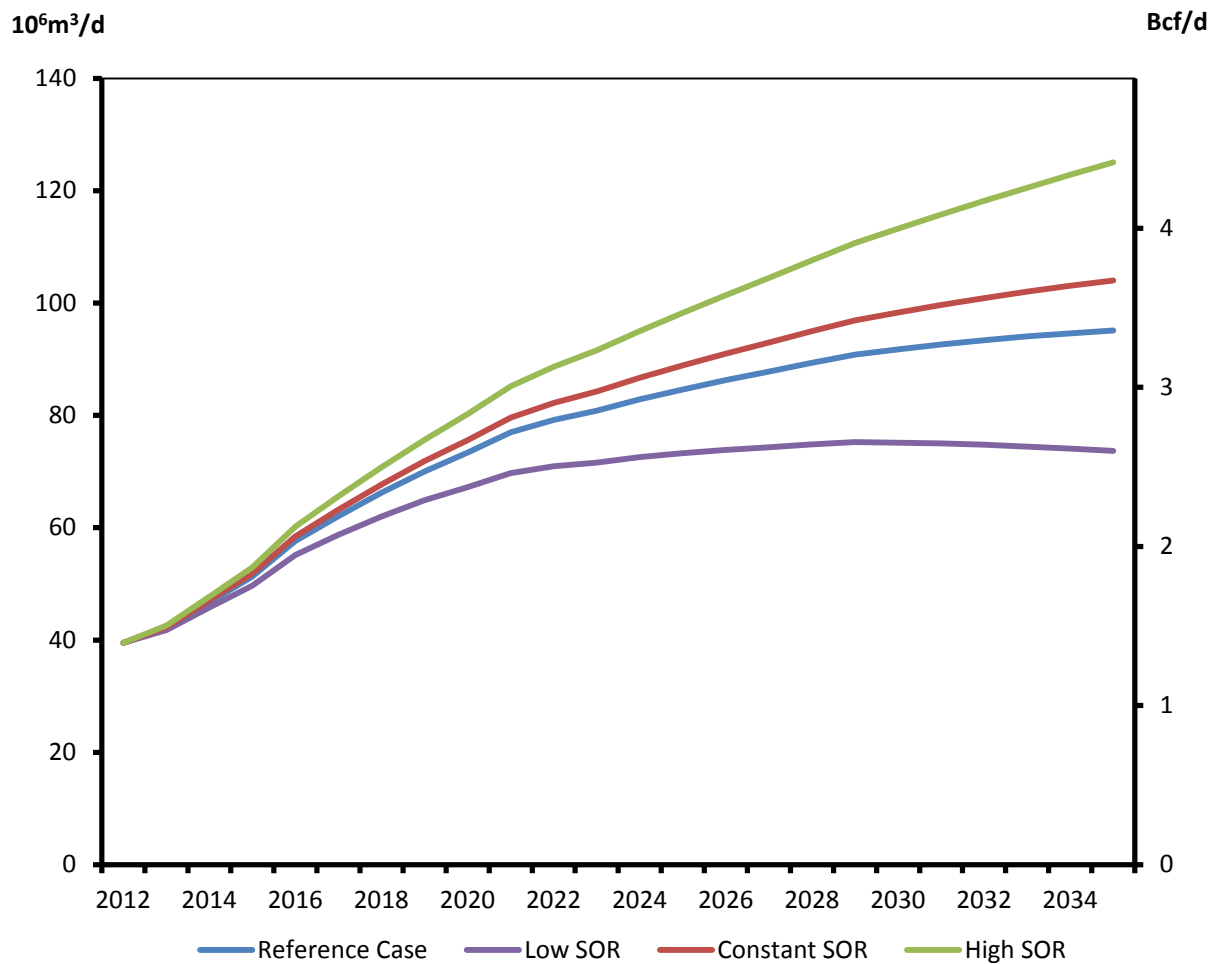
Figure 12 illustrates how sensitive total oil sands natural gas purchase requirements¹⁶ are to changes in the SOR. Oil sands natural gas purchase requirements range $51.4 \times 10^6 \text{m}^3/\text{d}$ (1.81 Bcf/d) between the High and Low SOR Cases in 2035. In 2035, natural gas use in the High SOR Case is $29.9 \times 10^6 \text{m}^3/\text{d}$ (1.06 Bcf/d) over the Reference Case, and $21.5 \times 10^6 \text{m}^3/\text{d}$ (0.76 Bcf/d) under the Reference Case in the Low SOR Case.

¹⁶ The Reference Case value is as shown in Figure 5.3 of EF 2013. This figure only includes natural gas purchased by the oil sands industry. In addition to purchased gas, the oil sands industry also uses natural gas that is produced along with oil sands production.

Altering the SOR assumptions has a notable impact on total Canadian natural gas demand. In the Reference Case, total primary natural gas demand increases at an average annual rate of 1.7 per cent, approximately 140 10⁶m³/d (5 Bcf/d; as shown in Figure 4). In the High SOR Case, primary natural gas demand increases by over 170 10⁶m³/d (6 Bcf/d) over the projection period, an average annual growth of two per cent per year. In the Low SOR Case, primary natural gas demand growth is 120 10⁶m³/d (4.2 Bcf/d), an average annual growth of 1.5 per cent per year. In 2035, total Canadian natural gas demand is eight per cent below the Reference Case in the Low SOR Case and six per cent above the Reference Case in the High SOR Case.

FIGURE 12

Purchased Natural Gas for Oil Sands Extraction and Upgrading, by Case



2.3 Carbon Capture and Storage (CCS) and Natural Gas Combined Cycle Power Generation

Issue and Background

As noted in EF 2013, federal regulations enacted in 2012 require new coal plants to reduce GHG emissions to no more than 420 metric tons of carbon dioxide (CO₂) per gigawatt hour (GWh). The regulation outlines stringent performance standards for new coal-fired electricity generation units and units that have reached the end of their useful life. Effectively, any new coal facility built after July 2015 is equipped with CCS. In EF 2013, several CCS facilities in Alberta and Saskatchewan come online over the projection period, reaching nearly 2 000 MW of capacity in 2035. Much of the growth in CCS occurs after 2020, replacing retired coal units or as a retrofit to existing coal plants.

Both Alberta and Saskatchewan are endowed with rich coal resources and are pursuing CCS technology to take advantage of the abundant resource and to satisfy future electricity demand. In the past few years, Alberta and Saskatchewan have announced long-term strategies, projects and financial commitments to assist in the building of coal power plants with CCS technology. The \$1.35 billion Boundary Dam CCS project in Saskatchewan opened in 2014. It is the world's first and largest commercial-scale CCS project, and is capable of producing 110 MW.

CCS is an emerging technology, and its long-term growth is uncertain. In the EF 2013 Reference Case, natural gas-fired generation supplies the majority of future electricity requirements in the two provinces. The EIA estimates of capital costs and energy requirements for natural gas combined cycle (NGCC) and CCS plants (Table 2) show lower costs for NGCC on a per kW basis. The *Alberta Electric System Operator's (AESO) 2014 Long Term Outlook* anticipates no new coal-fired plants over the next 20 years, mainly because of the unfavorable economics of CCS. Instead, the AESO Outlook anticipates combined cycle natural gas-fired generation to replace retiring coal-fired generation.

T A B L E 2

Capital Cost Estimates for Utility Scale Electricity Generating Plants

	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost¹⁷ (\$/kW)	Fixed O&M Cost (\$/kW yr)	Variable O&M Cost (\$/MWh)
Coal Single Unit Advanced PC with CCS	650	12 000	5 227	80.53	9.51
Coal Dual Unit Advanced PC with CCS	1 300	12 000	4 724	66.43	9.51
Natural Gas Conventional CC	620	7 050	917	13.17	3.60
Natural Gas Advanced CC	400	6 430	1 023	15.37	3.27
Natural Gas Advanced CC with CCS	340	7 525	2 095	31.79	6.78

Source: EIA¹⁸

Sensitivity Analysis

Considering these uncertainties, it is interesting to ask what the electricity and energy use impacts would be if the EF 2013 CCS additions are replaced with natural gas. The Capacity Switch Case assumes that the long-term CCS capacity additions included in the Reference Case are removed and replaced with NGCC units with the same generating capacity.

17 The term “overnight” refers to the cost of the project as if no interest were incurred during its construction.
 PC - pulverized coal
 CC - combined cycle
 CCS - carbon capture and storage
 O&M - operations and maintenance

18 Available at: <http://www.eia.gov/forecasts/capitalcost/>

Figure 13 compares Canada's capacity mix in 2035 for the Reference and Capacity Switch Cases. Relative to the Reference Case, the share of natural gas increases in the Capacity Switch Case, and the share of coal declines. EF 2013 projects Canada's total installed capacity to be over 164 000 MW by 2035, so the shift of 2 000 MW from coal to natural gas changes capacity shares by one per cent. This has the largest impact on coal use. The Capacity Switch Case shows that without the long-term CCS additions, projected coal capacity is lower than some renewable sources (non-hydro, non-wind¹⁹) while in the Reference Case the shares were about the same.

FIGURE 13

Canadian Capacity Mix in 2035, Reference and Capacity Switch Case

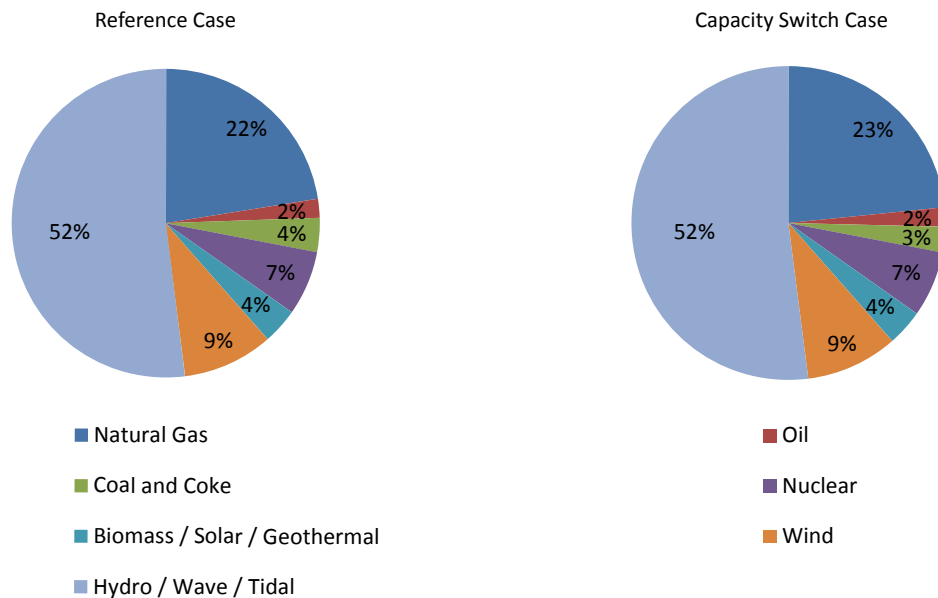


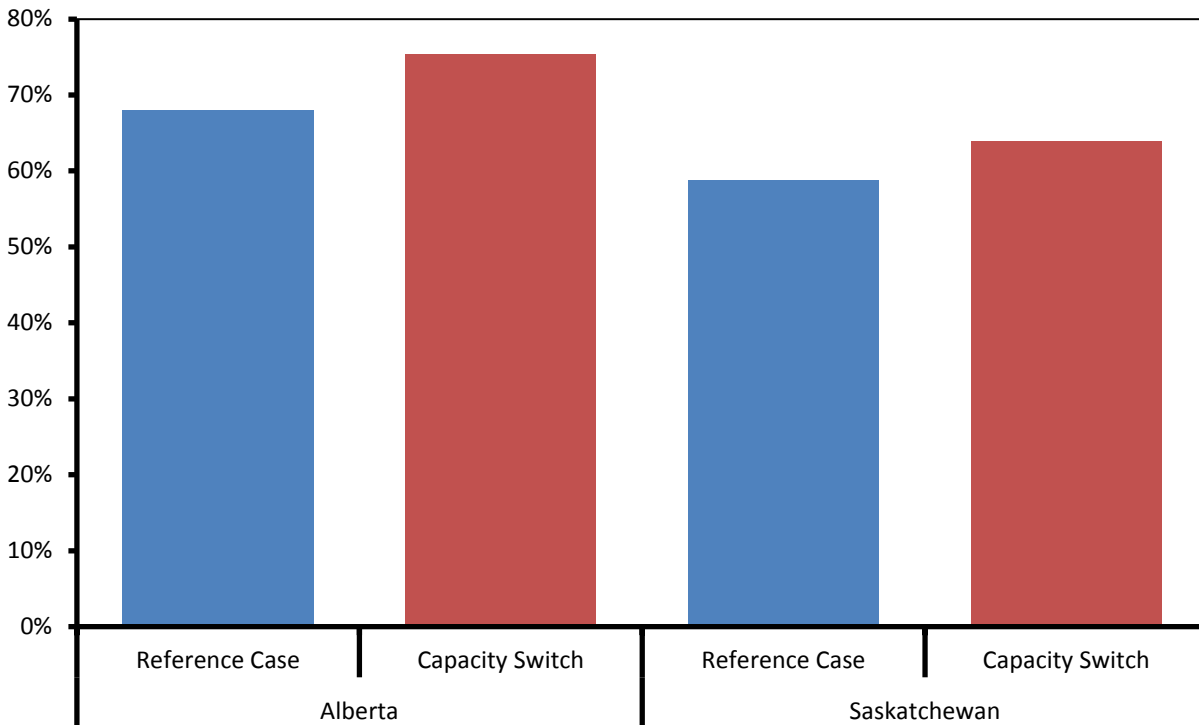
Figure 14 shows the share of natural gas-fired generation for Alberta and Saskatchewan in 2035 for the Reference and Capacity Switch Cases. The Reference Case values reflect strong growth in natural gas generation, with natural gas reaching 68 per cent of the 2035 generation mix in Alberta, and 59 per cent in Saskatchewan²⁰. In the Capacity Switch Cases, the reliance on natural gas generation is even higher. In Alberta, natural gas powers three quarters of the 2035 generation in the Capacity Switch Case, while in Saskatchewan natural gas makes up nearly 65 per cent of the generation mix.

19 Wind is an interesting case. It has a relatively low capacity factor (approximately 20-30 per cent), so although it accounts for nine per cent of the capacity mix in 2035, it accounts for four per cent of the generation mix. In terms of generation, coal (which often provides base load generation at a higher capacity factor) accounts for five per cent of generation in the Reference Case by 2035. In the Capacity Switch Case, however, coal-fired generation falls to three per cent, which is less than wind-powered generation.

20 In 2012, natural gas made up approximately 40 per cent of the mix in Alberta, and 25 per cent in Saskatchewan.

FIGURE 14

Share of Natural Gas-fired generation, Alberta and Saskatchewan in 2035, Reference and Capacity Switch Case



This shift also has implications for primary energy demand, as shown in Table 3. In the Capacity Switch Case, Canadian coal demand for power generation is 34 per cent or 130 PJ (5.5 Megatonnes) lower than the Reference Case in 2035. Natural gas demand for power generation becomes an even stronger driver for overall natural gas use. Canadian primary natural gas demand for power generation in the Capacity Switch Case is six per cent higher than the Reference Case in 2035 (approximately 75 PJ²¹ or 0.2 Bcf/d), growing to 1 450 PJ (approximately 4 Bcf/d).

TABLE 3

Power Generation Demand by Case, 2035

	Reference Case (PJ)	Capacity Switch Case (PJ)	Per Cent Change
Natural Gas	1 374	1 450	6%
Coal	387	257	-34%

21 In energy terms, the decrease in coal use is greater than the increase in natural gas use as CCS units are expected to have a higher heat rate than natural gas combined cycle units, as illustrated in Table 2. This means that CCS units require more energy to produce a kW of electricity than natural gas combined cycle units.

3. POWERING LNG: ALTERNATIVE OPTIONS

Issue and Background

The future for LNG exports is a key uncertainty in Canada's energy system. Currently there are a large number of proposed LNG export projects in British Columbia (B.C.) and a smaller number proposed on the East Coast. As of December 2014, none of the export project proponents have announced final investment decisions. To deal with this uncertainty, EF 2013 assumed one Bcf/d of LNG exports in 2019, two Bcf/d in 2021 and three Bcf/d by 2023.

When it comes to future energy use, an important uncertainty of potential LNG exports is the energy required to power the LNG export facilities. According to BC Hydro, LNG-related electricity demand falls into two general categories: compression (liquefying natural gas) and non-compression. Energy demand for compression is approximately 85 per cent²² of the total plant's energy needs. The remaining (non-compression) energy requirement is for plant pumps, motors, other equipment, heating and lighting.

EF 2013 assumes that all energy use related to LNG export facilities comes from natural gas-fired electricity plants. An additional 450 MW combined cycle unit is added in each of the years 2019, 2021, and 2023, corresponding to each assumed increment of LNG exports. At an end-use level, the electricity used by these plants was included in the industrial energy demand projection for B.C.

EF 2013 also noted this was only one of several potential options for meeting this demand. New LNG export facilities have a number of options to power their facilities. These options include:

- Direct Drive: uses natural gas as a fuel source to turn gas turbines for the liquefaction process. In most LNG plants, compression requirements are typically supplied with direct drive.
- Electric Drive, Self-generation: uses large electric motors to drive the compressors. Power is generated on-site by the LNG producer using natural gas as fuel source.
- Electric Drive, Grid Purchases: uses large electric motors to drive the compressors. Power is purchased directly from the B.C. grid.

BC Hydro projects LNG non-compression demand could be one of the biggest system loads, adding an additional peak demand ranging between 100 to 800 MW. Compression demands are expected to be met with direct drive or self-generation.

LNG project descriptions that were submitted to the Canadian Environmental Assessment Agency (CEAA)²³ and various project websites²⁴ shed some light as to how some of the proposed LNG projects plan to power their facilities. These are included in Table 3, and often involve some combination of the various options.

22 For more information see the latest BC Hydro Integrated Resource Plan at BCHydro.ca

23 <http://www.ceaa-acee.gc.ca>

24 See <http://www.woodfibrelng.ca>, <http://lngcanada.ca>

The Woodfibre LNG project is planning to purchase power directly from the grid as they try to take advantage of existing infrastructure that is already in place. The Pacific Northwest LNG project plans to generate its own power for the compression process while considering grid purchase for the non-compression demand. The LNG Canada project description states their intention to use natural gas direct drive for the compression process while considering purchasing power from the grid for auxiliary power. Recently LNG Canada has announced²⁵ that, if their project proceeds, they will be using GE's aeroderivative gas turbine for the compression process and power purchased from BC Hydro for the non-compression process. The Prince Rupert LNG project plans to design a self-sufficient facility where it has the capability to meet its entire power requirement.

T A B L E 4

Proposed Canadian LNG Export Projects That Have Stated Their Facility Powering Options

Project Description				Facility powering option		Estimated Load (MW)	
Name	Proponents	Location	Bcf/d	Compression	Non-compression	Non-compression	Total
LNG Canada	Shell Canada, PetroChina, Korea Gas & Mitsubishi	Kitimat	3.71	Direct drive	Grid Purchase	150	150
Pacific Northwest LNG	PETRONAS, JAPEX	Prince Rupert	3.15	Direct drive/Self-generation	Self-generation/Other	380	700*
Prince Rupert LNG	BG Group	Prince Rupert	3.34	Direct drive	Self generation/ Grid Purchase	200	800
Woodfibre LNG	Pacific Oil and Gas Group	Squamish	0.33	Grid Purchase	Grid Purchase	unknown	140
Aurora	Nexen, INPEX, JGC	Prince Rupert	3.11	Direct drive	Self-generation	unknown	300**

***Highest load expected at full operation**

****Highest load expected at full operation (at completion of phase 1)**

Source: CEAA, Project Websites

25 For more information see the project website, <http://lngcanada.ca>

Sensitivity Analysis

To analyze the impact of alternative methods of powering LNG on B.C. energy use, two alternative sensitivity cases are developed and compared with the Reference Case. These cases maintain the EF 2013 assumptions of one Bcf/d of LNG export in 2019, two Bcf/d in 2021 and three Bcf/d in 2023 (where it remains for the rest of the projection period), which are not related to any specific project.

The cases are described in Table 5. The alternative cases both assume that compression demands (85 per cent of total) are met by direct drive. This is in contrast to the Reference Case, where compression demands are met through electric drive. The alternative cases differ in how they treat non-compression demands. The Direct Drive/Self-generation Case assumes non-compression demands are met by self-generation via NGCC. The Direct Drive/Grid Purchase Case assumes that the non-compression requirement is met with electricity purchased from the grid.

T A B L E 5

Powering LNG: Alternative Options Case Description

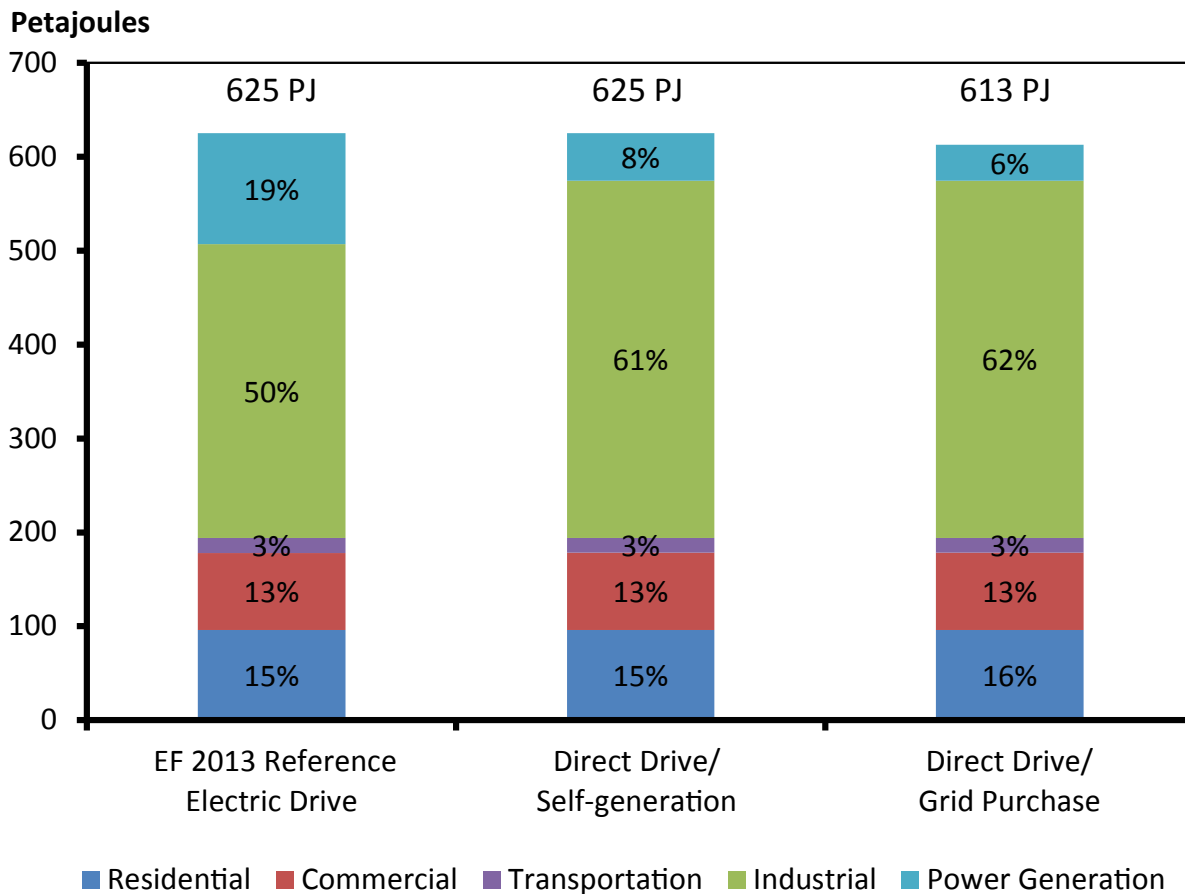
Case	Description
Reference Case (Electric Drive)	Total LNG demands met by using 0.2 Bcf/d of natural gas to generate 10 567 GWh of electricity for compression (electric drive) and non-compression demands
Direct Drive/Self-generation	Compression demands: Met by using 0.17 Bcf/d of natural gas directly Non-compression demands: Met by using 0.03 Bcf/d of natural gas to generate 1 528 GWh of electricity
Direct Drive/Grid Purchases	Compression demands: Met by using 0.17 Bcf/d of natural gas directly Non-compression demands: No additional capacity assumed to meet the 1 528 GWh of electricity. This demand is purchased from the grid.

Figure 15 shows B.C.'s total primary natural gas use in 2035 for the three cases, disaggregated by sector. Overall, the difference between these cases is fairly nuanced. As the figure shows, overall primary natural gas demand does not change much between the Reference Case and the Direct Drive/Self-generation Case²⁶. However, the sector using the energy for compression does change, as the energy used to generate natural gas in the Reference Case is now used directly in the industrial sector by the LNG facilities. Non-compression demands are satisfied through natural gas-fired generation, as in the Reference Case.

26 In all cases, the natural gas use for compression demands is assumed to be the same for electric drive and direct drive. This follows from the LNG volumes being general assumptions not tied to specific projects. Demands may vary depending on the specific technology chosen to power a given project.

FIGURE 15

B.C. Natural Gas Demand by Sector, 2035



The Direct Drive/Grid Purchase Case is identical to the Direct Drive/Self-generation Case for compression demands. The difference occurs on the non-compression side. In the Self-generation Case, approximately 200 MW of natural gas fired capacity is added to satisfy this demand directly. In the Grid Purchase Case this capacity is not added, and the electricity demands (1 500 GWh by 2035) are met with electricity purchased from the grid. In this analysis, all other assumptions are constant at Reference Case levels, and so these incremental electricity requirements are met mostly through reduced net exports. However, other possibilities include adding additional capacity (such as renewables), or taking additional demand-saving actions.

SUMMARY OF RESULTS

Topic	Sensitivity Case	Description	Results
1.0 Transport Demand and Demographic Trends	High VKm Case	Trends of increased driving intensity and licensing rates from the older age groups continue, while the decreasing trends from younger age groups flatten and/or reverse.	<ul style="list-style-type: none"> Total VKm increases at an average annual rate of 1.6 per cent over the projection period (compared with one per cent in the Reference Case). By 2035, passenger energy use is 13 per cent higher than the Reference Case.
	Low VKm Case	Trends of decreasing driving intensity and licensing rates from the younger age groups continue, while the increasing trends from older age groups flatten and/or reverse.	<ul style="list-style-type: none"> Total VKm increases at an average annual rate of 0.5 per cent over the projection period (compared with one per cent in the Reference Case). By 2035, passenger energy use is ten per cent lower than the Reference Case.
2.1 Natural Gas in Transportation	High NGV Case	Assumes a higher penetration rate of medium and heavy duty natural gas powered freight trucks (over 200 000 by 2035) than in the Reference Case (approximately 50-60 000 by 2035)	<ul style="list-style-type: none"> Natural gas used in freight transportation triples relative to Reference Case levels by 2035, a difference of 0.81 Bcf/d. The 2035 natural gas share in freight transportation increases to 23 per cent (from six per cent in the Reference Case), while the share of diesel drops from 67 per cent in the Reference Case to 50 per cent in the High NGV Case.
	High NGV+Rail Case	Natural gas-fueled freight trucks, plus a high penetration of natural gas in freight rail transportation.	<ul style="list-style-type: none"> Natural gas used in freight transportation increases by 361 per cent relative to Reference Case levels by 2035, a difference of 0.99 Bcf/d. The 2035 gas share in transportation is 27 per cent, while diesel is 46 per cent.

Topic	Sensitivity Case	Description	Results
2.2 Natural Gas Intensity for Oil Sands	High SOR Case	In situ oil sands SOR is assumed to increase at an average of one per cent per year over the projection period. In the Reference Case, it is assumed to decline by 0.5 per cent per year.	<ul style="list-style-type: none"> 2035 purchased natural gas requirements for the oil sands increase by 1.06 Bcf/d relative to the Reference Case.
	Constant SOR Case	In situ oil sands SOR is assumed to remain constant over the projection period.	<ul style="list-style-type: none"> 2035 purchased natural gas requirements for the oil sands increase by 0.31 Bcf/d relative to the Reference Case.
	Low SOR Case	In situ oil sands SOR is assumed to decrease at an average of two per cent per year over the projection period.	<ul style="list-style-type: none"> 2035 purchased natural gas requirements for the oil sands decrease by 0.76 Bcf/d relative to the Reference Case.
2.3 CCS and Natural Gas Combined Cycle Power Generation	Capacity Switch Case	Long-term Reference Case CCS capacity additions in Alberta and Saskatchewan (approximately 2 000 MW) are replaced with natural gas combined cycle.	<ul style="list-style-type: none"> 2035 natural gas use for power generation in Canada increases by six per cent (or 0.2 Bcf/d), while coal declines by 34 per cent, relative to the Reference Case. The share of coal capacity in 2035 in Canada declines from four per cent in the Reference Case to three per cent.

Topic	Sensitivity Case	Description	Results
3.0 Powering LNG: Alternative Options	Direct Drive + Self-generation Case	<p>LNG compression requirements (approximately 85 per cent of facility energy requirements) are met by “direct drive” technology, where natural gas is used directly. Non-compression requirements (the other 15 per cent of facility energy requirements) are met through on-site natural gas-fired generation.</p> <p>The Reference Case assumes all LNG requirements were met through natural gas-fired generation.</p>	<ul style="list-style-type: none"> Overall natural gas use remains similar to Reference Case levels, but the compression requirements are produced directly in the industrial sector instead of for power generation.
	Direct Drive + Grid Purchase Case	<p>LNG compression requirements are met by direct drive, which reduces the gas-fired capacity relative to the Reference Case. Non-compression requirements are met through grid purchases.</p>	<ul style="list-style-type: none"> Compression requirements for natural gas are produced directly in the industrial sector. Non-compression electricity requirements are met through power purchased from the grid. Since no additional capacity is assumed, the additional electricity largely comes from reduced net exports. However, it is possible the additional requirements could be met through additional capacity (such as renewables) or increased efficiency and/or conservation.

ABOUT THIS REPORT

The National Energy Board (NEB or Board) is an independent federal regulator whose purpose is to promote safety and security, environmental protection and efficient infrastructure and markets in the Canadian public interest within the mandate set by Parliament for the regulation of pipelines, energy development, and trade.

The Board's main responsibilities include regulating:

- the construction, operation and abandonment of oil and gas pipelines that cross international borders or provincial/territorial boundaries, as well as the associated pipeline tolls and tariffs;
- the construction and operation of international power lines, and designated interprovincial power lines; and
- imports of natural gas and exports of crude oil, natural gas, oil, natural gas liquids (NGLs), refined petroleum products and electricity.

Additionally, the Board has regulatory responsibilities for oil and gas exploration and production activities in frontier lands not otherwise regulated under joint federal/provincial accords. These regulatory responsibilities are set out in the *Canada Oil and Gas Operations Act* (COGO Act), the *Canada Petroleum Resources Act* (CPR Act). For oil and natural gas exports, the Board's role is to evaluate whether the oil and natural gas proposed to be exported is surplus to reasonably foreseeable Canadian requirements, having regard to the trends in the discovery of oil or gas in Canada. The Board monitors energy markets, and assesses Canadian energy requirements and trends in discovery of oil and natural gas to support its responsibilities under Part VI of the *National Energy Board Act* (the NEB Act). The Board periodically publishes assessments of Canadian energy supply, demand and markets in support of its ongoing market monitoring. These assessments address various aspects of energy markets in Canada. *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035* is one such assessment that projects Canadian energy supply and demand trends out to 2035. This report, *Energy Futures Supplement: Demand Sensitivities* complements the *Energy Futures* projections by exploring additional areas of long-term interest for Canada's energy system related to energy use.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material. This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

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LIST OF ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
AESO	Alberta electric system operator
B.C.	British Columbia
Bcf/d	Billion cubic feet per day
Btu	British thermal unit
CCS	Carbon Capture and Storage
CEAA	Canadian Environmental Assessment Agency
CNG	Compressed natural gas
CO ₂	Carbon dioxide
CSS	Cyclic steam stimulation
DGE	Diesel gallon equivalency
EF 2013	<i>Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035</i>
EFS	Energy Futures Supplement
EIA	Energy Information Administration
GWh	Gigawatt hour
HDVs	Heavy duty vehicles
iSOR	Instantaneous Steam oil ratio
kWh	Kilowatt hour
LNG	Liquefied Natural Gas
MDVs	Medium duty vehicles
MW	Megawatt
MWh	Megawatt hour
NEB	National Energy Board
NGCC	Natural gas combined cycle
NGVs	Natural gas vehicles
PJ	Petajoules
SAGD	Steam assisted gravity drainage
SOR	Steam oil ratio
U.S.	United States
VKm	Vehicle kilometres travelled

