An evaluation of input data, assumptions and functionality of the natural gas market modeling aspects in NEMS

Final Report for Resources for the Future
March 11, 2009, Ruud Egging, University of Maryland

This report reflects my opinion based on my current understanding of the Annual Energy Outlook documents and data provided by, and made available on the websites of, the Energy Information Agency. I want to thank Andy Kydes and Joe Benechhe for their willingness to provide additional data and explanation. Any errors in the document are solely my responsibility, and I would gladly receive comments: ruudegging - at - hotmail.com.

Preface

This report is an updated version of the Draft Report of Dec 10, 2008. Main differences are the inclusion of more explicit values in assumptions discussion sections, various additions and corrections based on discussions with Andy Kydes and Joe Benechhe (EIA DOE) and the addition and discussion of data obtained from the AEO 2009 early release. The starting point for this evaluation is still the 2008 Outlook, however several comments and recommendations have lost relevance due to changes in assumptions and modeling approaches as implemented in AEO 2009. As it turns out, the AEO 2009 projections cover some of our criticism in the draft report. For clarity old comments and recommendations have been kept in, but have been put in *italic* and assigned a [*comment that shows that the comment or recommendation has been addressed*]

In the AEO 2009 the incorporation of GHG emission policy assumptions positively affects the competitiveness of natural gas as a fuel for power generation. This induces a larger natural gas consumption for electricity generation, and brings the AEO2009 projections for total natural gas consumption more in line with previous projections by other institutions. A consequence of the higher consumption is higher prices, which is also more in line with other projections. However, the higher prices induce a larger domestic production, and virtual self-sufficiency by the end of the time horizon (2030). The recent reassessments and developments in unconventional gas production may warrant the higher domestic production levels providing near-self-sufficiency for several decades. However the presence of 5.2 Tcf/y in re-gasification capacity – more than 20% of yearly consumption – suggests that some variance in natural gas LNG import prices could induce a larger import share.

Executive summary

The projections in the Annual Energy Outlook 2008 sketch a relatively independent picture for the USA in the globalizing natural gas market. By 2030 over 85% of US gas consumption is projected to be supplied by US gas producers. When comparing the outlook with projections by other institutions, it turns out that across the board the import dependency of the US is expected to increase significantly, with a large part provided through LNG imports. This is also the case in the AEO 2008, but the LNG volumes in there are much lower.

The projected relatively high self sufficiency of the US roots in several assumed trends. First is a rather optimistic view on the domestic gas resource base, mainly in terms of production costs developments and accessibility of resources. Second is that due to efficiency gains in equipment and appliances, the growth in natural gas consumption will be moderate, and eventually turn into a decrease. The third is assuming relatively high availability from Canadian supplies (although much lower than nowadays) and rather negative assumptions for LNG costs and availability complete the picture.

The AEO 2008 seems to be in the optimistic part of the range of realistic assumptions and results at both the consumption and production side. Several recommendations are made to make the projections somewhat more conservative, although some recommendations by themselves could result in an even rosier picture.

TABLE OF CONTENTS

1 Introduction

This document discusses results and assumptions related to the US Natural Gas market in the Annual Energy Outlook 2008 energy market projections of EIA DOE. The modeling system used for the AEO projections is the National Energy Modeling System (NEMS), which consist of several modules. The focus will be on the modules related to supply and demand for natural gas. Therefore the modules that will be addressed are the Oil and Gas Supply Module (OGSM) and, the Natural Gas Transmission and Distribution module (NGTDM[1]), the various demand side modules, and the Electricity Market Module.

The objective of this document is to provide recommendations on the most important parameters and baseline model assumptions for a new set of policy runs. These recommendations can lead to an alternative reference case, co-existing beside the EIA reference case.

This document will address the levers that the NEMS models have to offer to assess the impact of policy initiatives; and what metrics are available (bbl, CO2, $$) to quantify the impact.

The remainder of this document is organized as follows. Several sections will successively focus on a separate aspects of the US NG[2] market. In order: consumption, production, the interaction with the Canadian and Mexican markets, LNG[3] trade, and domestic pipelines and storage. Each of these sections will start with discussing the outlook projections, sketching the main assumptions, discussing the results and the assumptions and concludes with providing recommendations. The last chapters addresses some other topics by providing overviews of how and which emissions are modeled in NEMS and how legislation is incorporated. Reported volumes are default in Tcf/yr[4] and bcf/day[5]. For reference section 7 provides some overview tables for supply, demand and prices for AEO 2008 and 2009. The appendix provides a table with unit conversion factors, lists what is covered by the sensitivity cases and some sources.

2 Consumption

2.1 Projections

Table 1 shows the projected natural gas consumption levels for the period up to 2030 by both AEOs. The columns for 2000 and 2005 show actual numbers. All but one sectors show a gradual increase over the whole projection period of the AEO 2008 (2006-2030). In AEO 2008 due to a projected decrease in electric power generation in the long run, total natural gas consumption is projected to reach a high around 2015, and decline afterwards. In contrast, AEO 2009 the growth continues longer and consumption plateaus around 2025.

[1] Not familiar with NGTDM? Section 1 Background/Overview of the NGTDM model documentation document provides a very succinct – four page - and clear description of the NGTDM and its role in NEMS.

[2] Natural Gas

[3] Liquefied Natural Gas

[4] Trillion cubic feet per year, 10^{12}

[5] billion cubic feet, 10^{9}

Table 1 Consumption by Sector[6] in Tcf/y

	PAST		AEO 2008				AEO 2009			
	2000	**2005**	**2008**	**2010**	**2020**	**2030**	**2008**	**2010**	**2020**	**2030**
Cons by Sector										
Residential	5.0	4.8	4.8	4.8	5.1	5.2	4.9	4.8	5.0	4.9
Commercial	3.2	3.0	3.1	3.0	3.4	3.7	3.1	3.1	3.3	3.4
Industrial	8.1	6.6	6.6	7.0	6.9	6.9	6.7	6.4	6.6	6.8
Electric Power	5.2	5.8	6.8	6.7	5.9	5.0	6.8	6.3	6.5	7.0
Transportation	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1
Pipeline Fuel	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.6	0.7	0.7
Lease & Plant Fuel	1.2	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.4
Total	**23.3**	**22.0**	**23.1**	**23.2**	**23.3**	**22.7**	**23.4**	**22.5**	**23.4**	**24.4**

Like in AEO 2008 in AEO 2009 it is also the consumption for electric power production that determines the overall trend. The difference of 2.0 Tcf in consumption for electric power in 2030 (Table 2) is more than the total difference of 1.7 Tcf (Table 3), showing that the higher prices (Table 4) reduce consumption levels in other sectors.

Table 2 Comparison of Consumption by Electric Power Production in Tcf/y

AEO	**2000**	**2005**	**2008**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
2009	5.2	5.8	6.8	6.6	6.3	6.0	6.5	7.4	7.0
2008	5.2	5.9	6.8	6.8	6.7	6.6	5.9	5.3	5.0
diff	0.0	-0.1	0.0	-0.2	-0.4	-0.5	0.6	2.1	2.0
	0%	-1%	0%	-2%	-6%	-8%	10%	39%	40%

Table 3 Comparison of Total NG Consumption in Tcf/y

		2000	**2005**	**2008**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
Total demand	**2009**	23.3	22.0	23.4	23.1	22.5	22.7	23.4	24.6	24.4
	2008	23.3	22.0	23.1	23.3	23.2	23.7	23.3	23.0	22.7
	diff	0.0	-0.1	0.3	-0.2	-0.8	-1.0	0.0	1.6	1.7
		0%	0%	1%	-1%	-3%	-4%	0%	7%	7%

Table 4 Comparison of NG delivered prices (USD/mcf[7])

delivered prices		**2000**	**2005**	**2008**	**2010**	**2020**	**2030**
average	**2009**	6.6	10.4	10.6	8.7	9.4	11.0
	2008	6.4	10.2	9.3	9.0	8.2	9.6
	diff	2.8%	2.2%	13.7%	-3.2%	14.1%	14.7%
	inflation corrected		-0.6%	10.6%	-5.9%	11.0%	11.6%
delivered prices		**2000**	**2005**	**2008**	**2010**	**2020**	**2030**
electric power	**2009**	5.3	8.9	9.4	6.7	7.3	8.9
	2008	5.1	8.7	7.4	7.2	6.1	7.1
	diff	2.8%	2.8%	26.7%	-7.1%	20.2%	25.4%
	inflation corrected		0.0%	23.3%	-9.6%	16.9%	22.0%

[6] Source: aeo2008.0302f.xls, for the reference scenario, Table 13
[7] mcf: 1000 cubic feet

delivered prices		**2000**	**2005**	**2008**	**2010**	**2020**	**2030**
residential	**2009**	9.3	13.4	13.4	12.3	12.9	14.7
	2008	9.1	13.2	13.0	12.5	11.7	13.3
	diff	2.8%	1.7%	2.6%	-1.8%	9.5%	10.7%
	inflation corrected		-1.1%	-0.2%	-4.4%	6.5%	7.7%

2.2 Assumptions

Some of the main assumptions underlying the demand projections have to do with population growth and household developments, industrial activity, and the fuels and technologies available for power generation.

Table 5 shows for several recent AEOs the assumptions for population and GDP growth, and for GDP growth the values used in the so-called low and high economic growth cases.

Table 5 Main assumptions AEO 2000, 2005, 2007, 2008, and 2009

AEO Reference	2000 (to 2020)	2005 (to 2025)	2007 (to 2030)	2008 (to 2030)	2009 (to 2030)
Population average growth	0.8%	0.8%	0.8%	0.8%	0.9%
GDP average growth (sensitivity range)	2.2% (1.7 - 2.6)	3.1% (2.5 - 3.6)	2.9% (2.3 - 3.4)	2.4% (1.3 - 3.0)	2.5%

Other parameters
Other important parameters concern technological progress and efficiency gains in equipment and appliances (such as computers, air conditioners, fridges and freezers), parameters for technology choice (how consumers and business select appliances and equipment), sizes of households and floor space of new-built houses and gains in distribution losses in the electric power generation sector.

Seasonality
Natural gas demand is a seasonal variable, highly influenced by outdoor temperatures. To address this, natural gas market models typically have different seasons among which demand levels vary. NGTDM implements two seasons. An eight month low demand season running from April through November, and a four month high demand period, from December through March. In the residential sector two factors that increase gas demand are the hot summer days and the cold winter days. Hot days result in *cooling degree days*[8] (CDD) and increased electricity use to power air conditioners, freezers and refrigerators. Cold days in *heating degree days*[8] (HDD), resulting in gas and electricity use for space heating.
Currently the 10 year averages for HDD and CDD are used to determine end-use consumption levels in the peak and off-peak seasons for the whole projection period up to 2030. See also section 6.3.

[8] Degree days: www.cpc.noaa.gov/products/analysis_monitoring/cdus/degree_days/ddayexp.shtml

Price-demand-elasticities

DISCUSSED AND ADDRESSED:

Short-term elasticity parameters determine how in the model demand responds to changes in the delivered prices. The values that are used are the following. For residential demand: -0.15. For commercial demand: -0.25 for all major end uses except refrigeration. For commercial refrigeration the used value is -0.1. For PC and non-PC office equipment and other minor uses of electricity, the used value is -0.05.

NGTDM does not work with inverse demand curves[9], and there is no immediate demand response to price-changes. The demand for a certain year is determined bottom up based on factors such as equipment stock and Heating and Cooling Degree Days. Supply prices and relative prices of other fuels affect equipment choices, and thereby the long term NG demand, and price-elasticity. The reported price-elasticities are mostly outputs, resulting from running the model under different assumptions and looking at the impact on demand volumes.

2.3 Discussion

The AEO 2008 projections for natural gas consumption in 2030 are lower than the values in other projections[10]. The differences vary from between 1.0 and 8.7 Tcf. A difference of 1 Tcf would imply that total consumption might not decrease after 2015. Higher values would imply significant other levels or mixes of the energy supply for the US overall. AEO 2009 projects 1.7 Tcf higher consumption, which brings the result within the range of other projections. However due to even higher upward adjustment of the production volumes, domestic production fulfills demand and the share of imports in the supply mix is almost negligible.

Among the residential, commercial, industry, transport and power generation, it is electric power generation that drives the consumption path going up first and down later in AEO2008 A mentioned reason is that power generation demand is much more responsive to price changes because there are fuel switching options. In AEO2009 the underlying assumptions for GHG policies make fuel alternatives less competitive, stimulating NG use for power, and inducing higher price levels overall.

The AEO 2009 upwards adjusted consumption for power is 20% higher than 2005 by 2030 is still rather low relative to projected values by the IEA projection of +50%. The reasons that EIA 2008 provides for the mid-term downward trend in electricity use are that penetration levels for computers and airco are meeting there saturation levels, and continuous improvements in electrical efficiency and significant improvements in electricity losses. Since the latter only account for about a 1% gain aggregate over the projection period, it must mostly be the improvements in electrical efficiency that are responsible for the moderate electric power consumption levels in the mid-term. Rather optimistic assumptions result in much lower AEO projected coal and natural gas use by 2030 relative to other projections. Reflecting on past projections and comparing projections with realizations, EIA notes that in recent past projections the AEO reference case had overestimated natural gas consumption, addressing significantly

[9] Some sub-sectors actually do, but that accounts for such a small part of consumption that we can safely neglect it for this discussion.

[10] This section uses information presented in AEO 2008 Comparison with other projections, page 90

lower natural gas wellhead price projections than what actually occurred.[11] However it is very well possible that parameters have been over-adjusted, making the long-term projections too conservative.

ADDRESSED BASED ON NEW INPUTS *The projected demand increases of other sectors are relatively modest, partially due to increasing energy efficiency characteristics. When discussing its past projections EIA states that it has underestimated technological progress and has revised its estimates positively. It is very well possible that technological progress for some appliances may have natural limits that prevent another 25 years of efficiency gains at the same rather high levels.* However in the literature values up to 1.5% are common[12]

Another aspect that seems not reflected in the modest growth projections, is the ability of human beings to spend the money freed up by appliances becoming cheaper over time on other, possibly newly invented appliances that also need energy to function. If stand-by energy levels decrease enough, computers, stereos and television sets will not be turned off at all anymore. Changing behavior as listening all day to that music channel of the television, or that old laptop with iTunes instead of the radio, using bigger flat-screen monitors, or using more than one monitor at time, and leaving on the computer in the office 24-7 to be able to access it remote-desktop from home if necessary. In the literature this effect is referred to as the rebound effect.[13]

The immediate rebound effect due to efficiency gains is accounted for. However I am not sure about the total income rebound effect. There is some evidence in the literature that the total amount spent on electricity is quite constant, so that the only way to reduce electricity usage would be an increase in costs in terms of real dollars per kWh.

The shape of learning curves for new technologies are exogenously determined, and provide cost and efficiency adjustments based on built-up stock.

DISCUSSED AND ADDRESSED
[I still have a question about how this may be reflected in the technology choice parameters.[14]]

Technology choice for several sectors is done through logit functions[15]. However for power generation it is a linear programming based cost minimization to meet load profiles (like Haiku).

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[11] This source is used here and at several other places: Annual Energy Outlook Retrospective Review, Report #: DOE/EIA-0640(2006), Release date March 2007,Next release date: February 2008,Annual Energy Outlook Retrospective Review: Evaluation of Projections in Past Editions (1982-2006) www.eia.doe.gov/oiaf/archive/analysispaper06/index.html

[12] Philippe Aghion and Peter Howitt, *Capital, innovation, and growth accounting*, Oxford Review of Economic Policy, Volume 23, Number 1, 2007, pp.79–93; Henrik Klinge Jacobsen, *Technological progress and long-term energy demand - a survey of recent approaches and a Danish case*, Energy Policy 29 (2001) 147-157

[13] See e.g. Henrik Klinge Jacobsen, *Technological progress and long-term energy demand - a survey of recent approaches and a Danish case*, Energy Policy 29 (2001) 147-157; Jeffrey Y. Tsao, Harry D. Saunders, Paul Waide *The Rebound Effect: An Analysis of the Empirical Data for Lighting*, presented at IAEE USAEE 2008 conference, New Orleans, Dec 2008; Horace Herring, Robin Roy, *Technological innovation, energy efficient design and the rebound effect*, Technovation 27 (2007) 194–203

[14] The focus of this report is with the Natural Gas Transmission and Distribution Module (NGTDM). I have looked into many other reports and manuals, but given the scope of this sub project have not been able to go into the full detail of many of them. Technology choice is very probably addressed in all the demand module documentations.

The below provides two illustrations for technology choice: Residential equipment replacement has two steps. The first is fuel choice, and than a one parameter logit function based on capital costs. For new equipment a two parameter logit function is used which integrates fuel in the capital cost decision. For transportation, for each vehicle type a five-parameter logit function is used which looks at several aspects.

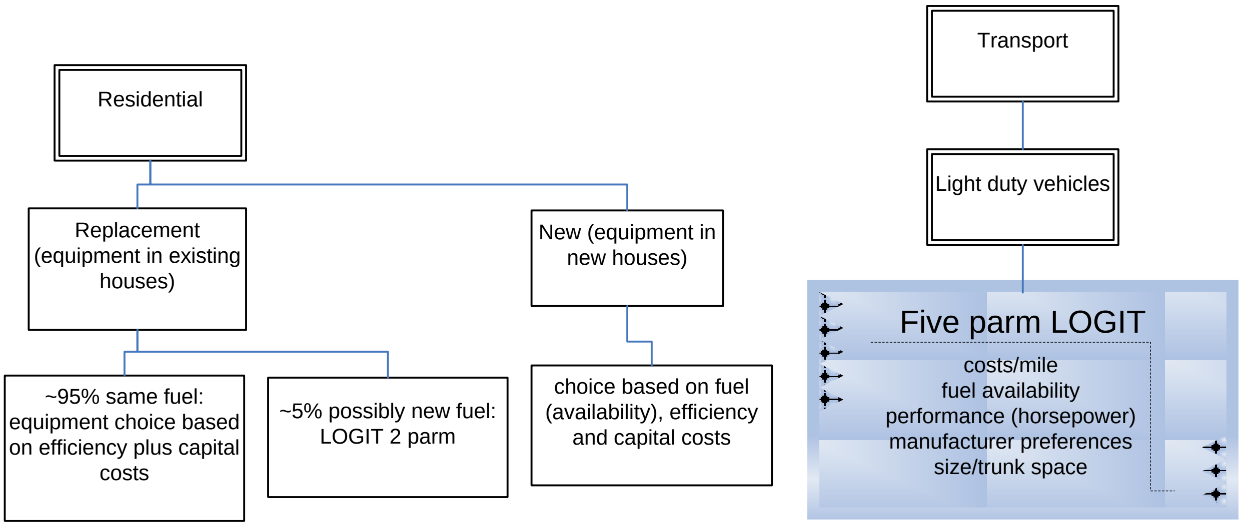

Table 6 Choice model illustration

The population growth assumptions are in line with United Nations[16] and IEA[17] projections.

The IEA GDP growth projection, 2.3%, is just slightly lower than the 2.4% and 2.5% of AEO 2008 and 2009 respectively. The average GDP growth has varied quite a lot among AEOs. As Table 5 shows the values used in 2005 and 2007 were not even within the values used in the low and high economic growth sensitivity cases of the AEO 2000. Later year's sensitivity ranges are broader, acknowledging that there is much uncertainty in this parameter that warrant a broader range between low and high economic growth assumptions.

Comparing the last two year's figures, we note that the AEO 2007 figure of 2.9% would have slightly more than doubled (+102%) GDP between 2005 and 2030 and the AEO2008 figure of 2.4% results in a 10% lower GDP in 2030 (+83.6%). The latter value brings the projected GDP in 2030 close to, but still slightly higher than projections by other institutions.

One of the sensitivity cases addresses how using a 30 year average for CDD and HDD instead of the 10 year average would impact the energy consumption. [Case Integrated alternative weather]. Although there is still a lot of debate, it is generally accepted that average temperatures on earth are rising due to the GHG effect. Rising temperatures will result in other CDD and HDD values,

[15] See e.g., http://www.marketingiq.com/help/software/logit/index.html
[16] Source: Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, World Population Prospects: The 2006 Revision and World Urbanization Prospects: The 2005 Revision, http://esa.un.org/unpp, Friday, March 06, 2009; 11:50:57 AM.
[17] IEA 2007 world energy model - methodology and assumptions

what is not accounted for when using past averages to define seasonal consumption levels. More HDD relative to CDD could imply less seasonal variation in gas flows and as a result might favor pipelines over storage. Beyond other seasonal patterns, also levels of yearly consumption may change.

DISCUSSED AND ADDRESSED:
The values used for price elasticities are always a difficult issue, mainly because it is very hard to assess their values. When we look at recent years' price and demand developments in for example the residential sector, with more than doubling consumer prices over a couple of years and seemingly no demand response, one could even argue that some demand sectors have negligible elasticity. The input values seem small enough, and with prices in terms of $2006 not changing that drastically, elasticities may hardly effect the projections. However, that could be different if demand curves over time are state in their nominal prices. A still open question is therefore whether price elasticities apply to nominal or to real prices?[18] *Because if they would apply to real prices, the roughly doubling of end-user prices in nominal terms even if they are stable in real terms would induce a 15% lower consumption level (ceteris paribus) in the residential sector which I would be skeptical about.*

2.4 Recommendations

I think that most assumptions regarding consumption developments are in the positive part of the range of realistic values. I would suggest to use more conservative estimates for several of the input parameters, focusing on energy efficiency and technological progress and the anticipated increased in average temperatures and changes in HDD and CDD. If demand curves and price-elasticities are in nominal terms I would also suggest to revise the price-elasticities. Since many of the used values are based on surveys, historical rates and expert or analyst judgment, there is no possibility to provide the one and only valid alternative values. My suggestions will take the by EIA used values as a starting point.

ADDRESSED BASED ON NEW INPUT:
(Table 52) Suggested values for technological progress in terms of costs and efficiencies for appliances and equipment could be to let them gradually decline from the historical average values that are currently used, to half the historical values halfway the projection period, say 12 years into the future and maintain the half values for the remainder of the period. Alternatively or complementing this, the technology choice parameters – that I assume are in the demand modules - may be adjusted in such a way that households and companies are more likely to spend more money on new appliances and equipment and/or maintain using old equipment for a longer period.

It seems that the long-term consumption projections in 2009 are still somewhat conservative relative to other projections. However, the increasing efforts by the US government relative to green energy and growing awareness of the US population regarding energy use and efficiency are not accounted for. The projected delivered prices in real terms are still modest relative to

[18] Elasticities and demand curves are probably addressed in all the demand module documentations. See also footnote 14.

most other projections, and higher prices could limit energy consumption growth or even lower consumption.

For anticipated temperature changes an assessment should be done on how the CDD and HDD are likely to change at a census region level over the projection period. These adjusted CDD and HDD values should be used to assess total consumption as well as seasonal loads in the demand modules.

ADDRESSED If demand curves and price-elasticities are in nominal $ terms in the model, a case can be made to make the elasticities smaller in absolute terms, to 'adjust for inflation'. For example, demand curves could reflect that, ceteris paribus, if real prices do not change, the demand levels remain constant.

3 Production

The main determinants for future domestic production levels – beside the demand levels – are production costs, resource bases and the availability and price levels of foreign supplies. The immediate neighbors Canada and Mexico play different roles in the gas trade relations with the USA. In recent years trade relations with Mexico are mostly seasonal and result in net exports on a yearly basis, whereas Canada is a net supplier, exporting about half of its production to the US. For that reason the Western Canadian Sedimentary Basin (WCSB) is represented as a production region in NEMS[19], both in OGSM[20] and – simplified – in NGTDM. The discussion of Canada and Mexico is done in a separate section (see section 4). This section will look solely to the US production projections (including Alaska.)

3.1 Projections

Incidentally the AEO2008 dry production values in 2000 and 2008 were both 19.18 and that had lead to some erroneous edits in the previous draft version.

In AEO 2008 the production levels (Table 7) are projected to slightly increase in the mid term, to start declining around 2025. After 2020 the Alaskan production should reach a significantly higher level when the Alaska-Alberta pipeline is put in place. To the contrary, AEO 2009 shows a gradual but significant increase over time. Note the large difference in 2008 production levels between the projection of 19.2 Tcf in AEO 2008 and the realization of 20.5 Tcf in AEO2009, indicating the recent spur in unconventional gas.

In AEO2008 through most of the period unconventional resources make up a bit less than half of the total production. Over time the fraction of gas shale production in total unconventional doubles to over 20%. Tight gas initially rises to about two-thirds of total unconventional production, but decreases after 2020. Coalbed Methane is produced at an almost constant level from 2010. The higher unconventional production levels in AEO2009 are solely responsible for the higher overall production levels.

[19] National Energy Modeling System
[20] Oil and Gas Supply Module

Table 7 Production projections [21]

	PAST		AEO 2008				AEO 2009			
	2000	2005	2008	2010	2020	2030	2008	2010	2020	2030
Production										
US Total	19.2	18.1	19.2	19.3	19.7	19.4	20.5	20.3	21.4	23.6
Lower 48 Onshore	13.6	14.3	15.5	15.3	14.2	14.0	17.0	16.7	16.1	16.8
Associated	1.8	1.4	1.4	1.4	1.3	1.2	1.4	1.4	1.4	1.3
Non-Associated	11.8	12.9	14.1	13.9	12.8	12.8	15.6	15.3	14.7	15.4
Conventional	6.1	4.9	5.1	4.8	3.5	3.2	5.2	4.7	3.4	2.2
Unconventional	5.7	8.0	9.0	9.0	9.4	9.5	10.4	10.6	11.3	13.2
Lower 48 Offshore	5.2	3.3	3.3	3.6	4.3	3.5	3.2	3.3	4.2	4.9
Associated	1.1	0.7	0.6	0.7	1.0	0.8	0.6	0.7	1.0	1.1
Non-Associated	4.1	2.7	2.7	2.9	3.3	2.7	2.6	2.5	3.2	3.8
Alaska	0.4	0.5	0.4	0.4	1.2	2.0	0.4	0.4	1.1	2.0
Unconventional	**5.7**	**8.0**	**9.0**	**9.0**	**9.4**	**9.5**	**10.4**	**10.6**	**11.3**	**13.2**
Gas Shale	0.4	0.8	1.1	1.2	1.8	2.2	1.6	2.3	3.0	4.1
Coalbed Methane	1.5	1.8	1.8	1.8	1.7	1.8	2.0	1.8	1.8	2.0
Tight Gas	3.8	5.4	6.1	6.0	5.9	5.5	6.8	6.5	6.6	7.1

In AEO2008 the wellhead prices (Table 8) are projected to gradually decrease from the high 2005 levels until the middle of the projection period. After 2020 they should gradually rise to just slightly above the 2010 levels – real $ terms - in 2030. AEO 2009 shows a similar pattern, with initially lower prices, but a quicker upward rebound. The table also shows that the AEO2008 wellhead prices were much lower than the realized wellhead prices.

Table 8 Natural Gas Supply Prices

	PAST	AEO2008 ($2006)					AEO2009 ($2007)				
	2000	2005	2008	2010	2020	2030	2005	2008	2010	2020	2030
(USD per mmBtu)											
Henry Hub Spot	5.2	8.9	7.2	6.9	5.9	7.2	9.2	9.0	6.5	7.4	9.2
Average Lower 48 Wellhead	4.2	7.6	6.4	6.2	5.3	6.4	7.8	7.8	5.8	6.6	8.2
(USD per mcf)											
Average Lower 48 Wellhead	4.3	7.8	6.6	6.3	5.4	6.6	8.1	8.0	5.9	6.8	8.4
Delivered Prices											
Residential	9.3	13.2	13.0	12.5	11.7	13.3	13.4	13.4	12.3	12.9	14.7
Commercial	8.0	11.9	11.4	10.9	10.2	11.8	12.0	11.8	10.7	11.4	13.3
Industrial	5.1	8.6	7.6	7.4	6.4	7.5	8.9	9.2	7.0	7.7	9.3
Electric Power	5.3	8.7	7.4	7.2	6.1	7.1	8.9	9.4	6.7	7.3	8.9
Transportation	10.7	15.0	14.2	14.0	12.5	13.2	15.3	17.5	15.2	15.3	16.7
Average	**6.6**	**10.2**	**9.3**	**9.0**	**8.2**	**9.6**	**10.4**	**10.6**	**8.7**	**9.4**	**11.0**

[21] Source: ftp://ftp.eia.doe.gov/pub/oiaf/aeo/aeo2008.zip: aeo2008.0302f.xls, Table 13 and 14. Oil and Gas Supply. Supplemental Natural Gas, at 0.1 Tcf/year by assumption, is left out of the table.

3.2 Reserves Assumptions

Table 9 provides the details for the technically recoverable reserves as they are assumed for the AEO 2008. The proved reserves are slightly higher than 200 Tcf, about eleven times the actual production level of 2007. Unproved reserves add up to 1160 Tcf, which would last about fifty years at current production levels.

Table 9 Technically Recoverable Resources (Tcf)

Lower 48 Non-associated Conventional Gas			500		
Undiscovered				273	
Onshore					116
Offshore					158
Inferred Reserves				227	
Onshore					171
Offshore					56
Unconventional Gas Recovery			500		
Tight Gas				304	
Shale				125	
Coal bed				71	
Associated-Dissolved Gas			130		
Total Lower 48 Unproved		1129			
Alaska		31			
Total U.S. Unproved	1160				
Proved Reserves	204				
Total Natural Gas Reserves	1365				

3.3 Alaska

The projected level of production in Alaska is intertwined with several issues. At the moment there is local consumption, and a facility that exports LNG to Japan. In a few years the LNG facility will be phased out and in the long run a pipeline may be built, as well as – by assumption - a gas to liquid facility. See section 6 on pipelines and storage for details.

The aggregate Alaska North Slope natural gas production in the EIA forecast is limited to 26 Tcf of stranded gas reserves, in the Prudhoe Bay and the Port Thompson fields. The total estimated reserves of these fields add up to 35 Tcf, but the remainder (35-26=9 Tcf) is assumed to be needed for injection to facilitate North Slope oil production.

October 2008 USGS announced 85 Tcf of undiscovered, technically recoverable gas resources within gas hydrates reservoirs in northern Alaska.

In their Mid-term commodities outlook of 11 January 2008 Deutsche Bank assumed a 2015 start year for the Alaskan pipeline. This seems highly unlikely. TransCanada mentions 2018, which seems rather ambitious.

3.4 Unconventional

Unconventional resources – tight, shale and coal bed methane (CBM) – make up slightly over 40% of total undiscovered resources. Tight gas is thought the largest of the three, about 25% of *total* undiscovered resources. Shale about 10%, and CBM about 5%.

The AEO 2009 shows much higher production from tight and shale, which is one of the main revision in this outlook relative to last year's.

3.5 Other Assumptions

Oil prices have played – and still do play – a major role in the price-setting of natural gas. The link between oil and gas prices shows in contracts – e.g. in LNG contracts, or price-adjustment clauses for supplies to residential or commercial sectors, but is also market driven in other way since in some applications the fuels are substitutes. Oil prices drive the OGSM module, by triggering investments and production levels, both domestically and overseas. The world oil price assumptions[22] used in the AEO 2008 for 2030 is $70/bbl. The values in the low and high oil price cases are $39 and $130.

Table 10 Oil prices AEO2008 ($2006/bbl)

	2000	2005	2010	2015	2020	2025	2030
Lower 48 Average Wellhead Price	32	52	78	58	53	56	61
Low Sulfur Light Price	***35***	***58***	***74***	***60***	***60***	***64***	***70***
Imported Crude Oil Price	31	50	65	52	52	56	59

Natural gas from liquids, other supplemental supplies and synthetic production of gas from coal have been exogenously set based on historic values. The aggregate level for the three of them is 0.1 Tcf/year, about ½ % of total gas production.

Technological progress reduces the production costs of natural gas and enhances earlier accessibility to recoverable resources. The assumed reference scenario progress values vary between 0 and 3%[23]. With cost and success factors adding to each other, the total assumed efficiency gain over a 25 year period can be quite large (i.e. more than double).

In the reference scenario the Arctic National Wildlife Refuge (ANWR) is not expected to become accessible for exploration and production. There is a sensitivity case dedicated to show the impact of oil E&P from the ANWR. Any natural gas found would be re-injected to enhance oil recovery, so no gas would be available to supply to the consumption sectors.

3.6 Discussion

EIA states in its own evaluation document that historically the fuel with the largest deviations between projections and outcomes has been natural gas. They address as the main causes:

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[22] For: Low Sulfur Light Oil

[23] Table 52. Assumed Annual Rates of Technological Progress for Conventional Crude Oil and Natural Gas Sources, Assumptions to the AEO 2008, page 105

regulatory reforms and changes in policy[24], speedier technological improvement and the quality of natural gas resource estimates.

Other reasons one could imagine to be playing a role here is that in some parts of both demand and supply side natural gas is a *marginal* fuel. Natural gas is generally not a base load fuel in electricity production (although this may change due to GHG policies) but a peak load fuel. Prevailing spot market prices have an almost immediate impact on the volume of gas used for electric power production. At the supply side, the short time to bring shale gas reservoirs into production also allows a relatively short-term supply response to market prices.

The AEO 2008 projections for natural gas production in 2030 are between 0.5 and 3.0 Tcf higher than of other projections. Previously we noted that the consumption levels of AEO were lower than any other. As a result the import share of natural gas relative to total consumption is much lower in the AEO projections than in others. See section 5 on LNG for more details. AEO2009 projections are even higher, but mostly due to revised gas shale assumptions based on recent developments. The much higher production in 2008 than projected only a year ago provide some rationale.

Recent projections from the Rice WGTM have wellhead prices gradually increase from $6/mcf in current days to about $8/mcf in 2030. The Canadian Energy Board uses a $6.5/mcf baseline for their recent natural gas market projections. Some informal conversations at the USAEE conference early December 2008 indicate that some unconventional techniques need a wellhead price in the $6-7 range to be competitive[25]. And, although it is projected to supply only 20-25% of total production, the increasing depths of exploration areas for offshore drilling and production challenge technology and add to the costs. Generally the AEO 2008 wellhead price projections seem to be at the lower end of the realistic range. Interestingly the AEO2009 projected wellhead prices are in the same range as the RICE projections, although still lower than (less recent) projections such as WETO.

Regarding reserves, the proved reserves base of slightly more than 200 Tcf is not controversial However, more than 80% of the assumed resource base is yet to be discovered. Moratoria on some regions with proved reserves may or may not be lifted or eased. For some regions, such as the Eastern Gulf of Mexico, the yearly returning hurricane season adds supply security to environmental and wildlife considerations in the decision making process regarding opening them up for exploration and production.

Mean undiscovered reserves estimates for the US vary. USGS put the onshore resources on 655 Tcf[26], of which 95 Tcf can currently not be accessed[27]. The MMS[28] in a 2006 assessment puts the resources in undiscovered fields on the outer continental shelf (offshore) at 420 Tcf, 20% of

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[24] EIA is by law enforced to take the current and decided upon policy framework for what they use in their projections.

[25] Kuuskraa indicates that under $5/mcf many unconventional gas resources would be uneconomic www.adv-res.com/unconventional-gas-literature.asp

[26] USGS Oct 2007: 655 Tcf, Total Mean Undiscovered Gas Resources

[27] BLM 2008 Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development PHASE III INVENTORY – ONSHORE UNITED STATES

[28] Minerals Management Service

which is currently off limits to leasing and development[29]. Total undiscovered reserves are: 420+655=1075 Tcf; 896 of which in currently accessible areas.
For ten years straight, the US have been able to find at least as much in new natural gas reserves than as was produced in that year, and proved reserves have steadily increased from 164 Tcf in 1998 to 211 Tcf in 2006 and 2007. Current proved reserve levels are the highest since 1980, the first year for which BP statistics presents data[30]. Oil and gas companies do *not* have incentives to explore much quicker and find more reserves, because exploration costs are high, and if the time to production and earnings is long, immediate costs have a large impact on the Net Present Value of each project. Finding new reserves will become more technologically challenging and possibly costly, since the low-hanging fruit has been harvested. For instance, new drilling for offshore wells is approaching depths of 10,000 feet.

To account for some variability, EIA uses -15% and +15% as a low and high estimate in some of the sensitivity cases.

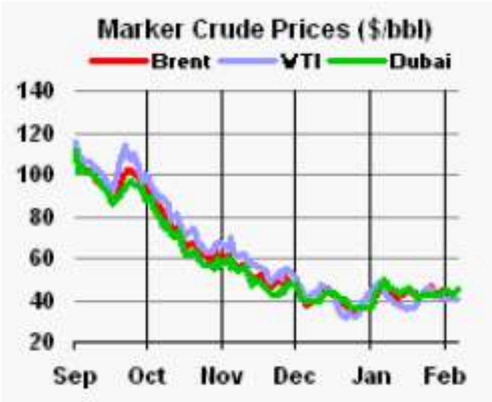
Table 11 Oil prices for Brent in US dollars per barrel [31]

Year	$ 2007
1999	23
2000	35
2001	29
2002	29
2003	33
2004	42
2005	58
2006	67
2007	72

Five years ago the general idea was that an oil price of $30/bbl is a reasonable long term figure. In AEO 2000 the mean projection was (1998$) $22 for 2020 and the low and high oil price cases assumed: $15 and $28/bbl. The AEO 2005 low and high values were: $21 and $35, with extra cases $40 and $48/bbl. In response to the rapidly increasing prices in 2004 and 2005 the long term oil price projections have increased significantly over the last years, and in the 2008 projections, the low and high price have been adjusted accordingly. The relatively high prices in 2005 have generally – also in other institutions' projections - lead to initially decreasing prices in the mid-term to gradually increase again further towards 2030. In acknowledgment of the variance and higher levels of oil prices, the level and bandwidth of oil prices used in the AEO sensitivity cases has also been increased. In 2007 the low, mean and high prices were: 36, 61 and 100. The 2008 references values are even 10-15% higher than the 2007 values, and the high end oil price assumption for 2030 of $130 seems not so farfetched in light of over $150 oil prices last Summer 2008. These days the oil price is in the lower forties.

http://omrpublic.iea.org/

[29] MMS 2006 Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources Energy Policy Act of 2005 – Section 357
[30] www.bp.com
[31] BP Statistical Review of world energy 2008



Generally, the wide range in the sensitivity cases acknowledges the inherent variability and unpredictability of oil prices.

The assumed values for technological progress over time add up to rather large improvements in efficiency and costs. In its evaluations EIA states that technological improvement assumptions in early AEOs turned out to be conservative. It is possible that in a response to that the current values are in the optimistic end of the range. The AEO 2008 low and high technology cases use 50% lower and higher values for technological progress parameters. Advanced Resources International[32] addresses a decline in technological progress for tight gas and CBM, although not for gas shale. Another aspect that comes into play here is that AEO still projects relatively modest increases in gas prices. Higher gas prices would imply that more (unconventional) resources would become economical with current technology, but would also trigger higher investments, allowing for more technological progress in the long run.

DISCUSSED AND ADDRESSED: *The supply from supplemental sources (such as synthetically produced gas from coal), is set at historical rates. In light of US' huge coal reserves this prevents the possibility of higher output levels in response to higher prices. Given the projected decrease in Canadian supplies, the supplemental sources could possibly supply a similar amount of gas by the end of the projection horizon as the imported volumes from Canada. [Supplemental is not close to competitive]. Would it be reasonable to have these supplies be endogenously determined by the model? Or are there reasons to assume that the would add not value to the long term energy projections?[Supplemental supplies are not even close to competitive]*

DISCUSSED AND ADDRESSED: *Looking into Table F11. Base price for natural gas supply curves I did not understand some choices that seem to have been made in the regression analysis Why do the lagged values have the same alpha-coefficients as the non-lagged variables? Now the determined alpha's apply to both variables. I think it would be appropriate to estimate different alpha's. Besides that, there are some P-values that imply that the found values are not-significant, so should not be used in the model. [This part of the documentation was not up to date anymore.]*

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[32] Kuuskraa 2007, A Decade of Progress in Unconventional Gas, www.adv-res.com/unconventional-gas-literature.asp

3.7 Recommendations

Production levels and wellhead prices seem to be quite optimistic, but since the reserve base seems to be in line with detailed estimates available, this may be mostly due to the positive assumptions regarding technological progress. The jump in production in the year 2008 reflected in AEO 2009 indicates that last year's outlook on production volumes may have not been as optimistic as earlier thought. Higher gas prices allow more marginal resources to be operated economically, and trigger higher investments.

It is hard to justify or validate alternative suggestions for values for technological progress. There is a risk of basing recommendations on the desired outputs, i.e. outputs more in line with other projections. However using constant technological progress figures over a long period of time may let efficiency values grow over possible 'natural' upper limits. Maybe an S-curved shape, with initially higher progress, but slowing near the end, would be more appropriate. This would be possible, however it would be hard, to justify how to shape the ascent and descent of the curvature. To keep it simple, to moderate the technological progress assumptions the values could be reduced with ¼, leading to values halfway the reference case and the low technology case. If this seems too harsh, a similar approach as in section consumption could be to start with the current AEO assumptions, and let them gradually (e.g. linearly) decrease so that halfway the projection period the ¼ moderation is reached. Consulting more input sources and in light of recent developments I would suggest to keep technological progress parameters at current levels.

DISCUSSED AND ADDRESSED: [More clarification for the assumptions regarding supplemental supplies.] I will contact Andy Kydes or Joe Benecchi to ask them for some explanation.

Based on the analysis I see no reason to adjust the undiscovered resource base. Moratoria are set to expire, and unless a choice would be made to have a 'realistic conservative' reference case, in which case a downward adjustment to 896 Tcf – the mean estimate for resources in currently accessible areas – would be justified.

DISCUSSED AND ADDRESSED: I stated some questions about the approach used for the regression analysis for Base price for natural gas supply curves. I would recommend they be addressed in discussion with the person who did the analysis.

See also section 6 for more discussion of the Alaskan supply situation.

4 Canada and Mexico

The neighboring countries Canada and Mexico play significant roles in the energy trade relations with the USA. Gas trade with Mexico is mostly seasonal and resulted in recent years in net exports on a yearly basis. In contrast, Canada is a net supplier, exporting about half of its production to the US and in the present world providing the main share of total US natural gas imports. For that reason Canada is modeled in more detail in the NEMS and NGTDM than Mexico. This section present in some detail the energy outlooks for Canada and Mexico.

4.1 Projections

In the most recent International Energy Outlook[33], EIA projects natural gas consumption in OECD North America to increase at an average annual rate of 0.6 percent from 2005 to 2030. For the United States the average annual increase is much lower; Canada and Mexico contribute much more to the continental growth in gas use. Due to upward revisions for the US consumption the IEO 2009 will probably show a higher than 0.6% average continental growth.

Every couple of years Canada's National Energy Board develops energy outlooks for Canada[34]. The most recent outlook was published in 2007. It contains three scenarios, this section presents values from the *continuing trends* scenario, which is the reference scenario. The following section presents some figures for the natural gas projections. These figures will allow us to compare the assumptions made by EIA for the Canadian supply and demand situation.

Canada and Mexico are the only countries with which pipeline trade can take place. All other trade (Alaskan exports to Japan, imports from other countries) are LNG. In AEO 2008 the total net imports are projected to stay relatively constant, with exports to Mexico slightly growing and the share of LNG gradually increasing, to offset the lower imports from Canada. By contrast, in AEO 2009 the increasing domestic production offsets the decline in Canadian exports.

Table 12 International Trade (Tcf/y)[35]

AEO / Year	AEO 2008				AEO 2009			
	LNG	Canada	Mexico	Total	Total	LNG	Canada	Mexico
2000	0.2	3.5	-0.1	3.5				
2005	0.6	3.3	-0.3	3.6				
2008				3.9	2.9	0.3	2.5	0.0
2010	1.2	2.8	-0.1	3.8	2.5	0.5	1.6	0.4
2015	2.1	2.2	-0.2	4.0	2.4	1.3	1.1	0.0
2020	2.4	1.4	-0.3	3.6	1.9	1.4	0.7	-0.2
2025	2.6	1.1	-0.5	3.3	1.4	1.2	0.6	-0.5
2030	2.8	0.9	-0.5	3.2	0.7	0.8	0.5	-0.7

4.1.1 Canada

Previously there was a mismatch between NEB and EIA outlook for the US Canadian gas trade projections. The EIA projected imports were higher than the NEB projected exports, and LNG imports would have been the likely option to fill the gap. Since in the AEO2009 the US domestic production grows so much more, the trade balance with Canada is closer to the NEB projection.

[33] http://www.eia.doe.gov/oiaf/ieo/pdf/nat_gas.pdf, page 37, Figure 36

[34] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyrprt-eng.html, 'Energy futures'

[35] Positive values are net imports, negative values are net exports. AEO 2009 Trade with Mexico own calculations based on AEO2009 and Canadian data obtained from Joe Benneche.

In its 2008 International Energy Outlook EIA projects Canada's total natural gas consumption to increase steadily, at a rate of 1.5 percent per year, from 3.4 trillion cubic feet in 2005 to 5.0 trillion cubic feet in 2030.

Table 13 shows the Canadian NEB projections for Canadian production. Total production is projected to decline with 40% between 2005 and 2030, from 6.2 to 3.8 Tcf. The NEB is working on a revision of its projections that should account for changed oil prices and developments in unconventional gas.

Table 13 National Energy Board's supply projections Canada (Tcf/y) [36]

	2000	2005	2010	2015	2020	2025	2030
Canada	**6.2**	**6.2**	**5.8**	**5.5**	**4.9**	**4.4**	**3.8**
WCSB[37]	*6.1*	*6.1*	*5.6*	*5.2*	*4.3*	*3.4*	*2.7*
Alberta	5.1	4.9	4.4	4.0	3.2	2.4	1.8
British Columbia	0.8	0.9	0.9	0.9	0.8	0.9	0.8
Newfoundland	0.0	0.0	0.0	0.0	0.2	0.4	0.4
Northwest Territories	0.0	0.0	0.0	0.3	0.4	0.7	0.7
Mackenzie	*0.0*	*0.0*	*0.0*	*0.3*	*0.4*	*0.7*	*0.7*
Nova Scotia	0.1	0.1	0.2	0.1	0.0	0.0	0.0
Ontario	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Saskatchewan	0.2	0.3	0.2	0.2	0.1	0.1	0.0

Table 14 shows LNG imports. Three LNG import terminals are expected to become operational. Imports increase steadily over time to reach about 1 Tcf/y by 2030.

Table 14 National Energy Board LNG imports Canada (Tcf/y) [38]

	2000	2005	2010	2015	2020	2025	2030
East Coast	0.00	0.00	0.18	0.37	0.37	0.37	0.51
Quebec	0.00	0.00	0.00	0.15	0.29	0.29	0.44
British Columbia	0.00	0.00	0.00	0.00	0.11	0.11	0.11
Total LNG Imports	0.00	0.00	0.18	0.52	0.77	0.77	1.06

Table 15 presents the primary and secondary[39] demand for natural gas. Between 2005 and 2030 total natural gas demand is expected to grow with about 25%.

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[36] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html, Table A4.2: Natural Gas, Reference Case and Continuing Trends, Production Outlook

[37] Includes Alberta, British Columbia, Other Northwest Territories, Saskatchewan and Yukon

[38] NEB Table A4.2

[39] www.nrcan.gc.ca: **Primary energy demand** comprises secondary energy demand, non-combustion uses of energy, and the energy industry's supply requirements. **Secondary demand** is the sum of energy use in the residential, commercial, industrial and transportation sectors. **Electricity** is produced as primary as well as secondary energy. www.iea.org: **Primary electricity** is obtained from natural sources such as hydro, wind, solar, tide and wave power. **Secondary electricity** is produced from the heat of nuclear fission of nuclear fuels, from the geothermal heat and solar thermal heat, and by burning primary combustible fuels

The main driver for the Canadian consumption is industrial natural gas demand, averaging 2.0 percent per year, among other reasons to facilitate the mining of oil sands deposits

Table 15 National Energy Board Natural Gas Demand Canada (Tcf)[40]

	2000	2005	2010	2015	2020	2025	2030
Primary demand	3.8	4.1	4.4	4.8	5.0	5.0	5.2
Primary Demand 2005=100		100%	108%	117%	122%	123%	126%
Secondary demand	3.5	3.6	3.8	4.1	4.3	4.4	4.5
Secondary Demand 2005=100		100%	105%	114%	118%	121%	123%

The NEB takes as their reference projection a (stable) price at Henry Hub of ($2005) US$7/MMBtu, which is approximately $7.0/mcf ($2006)

Table 16 Canadian Trade balance (Tcf)[41]

	2000	2005	2008	2009	2010	2015	2020	2025	2030
Prod	6.2	6.3	6.2	6.1	5.3	5.1	5.0	5.3	5.5
LNG	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0
Cons	3.0	3.4	3.7	3.7	3.7	4.1	4.4	4.6	5.0
Pipe	3.2	2.9	2.5	2.4	1.6	1.1	0.7	0.6	0.5

4.1.2 Mexico

Mexican consumption in 2005 was close to 2 Tcf [42]. 17% of this amount was imported, all from the USA via pipelines. Mexican proved reserves amount to 13 Tcf [43], which at a production level of 1.6 Tcf is about eight years worth of production. Mexico has many unexplored areas, e.g. in the Mexican part of the Gulf of Mexico. Besides EIAs figures I have not been able to find credible long term projections for Mexican natural gas.

Both consumption and production are expected to grow significantly over the years to come. With several LNG terminals constructed recently and on their way, Mexico is expected to remain a net importer of natural gas, however the gas balance to the US may shift from net importer to net exporter. In 2007 Mexico imported LNG from Trinidad & Tobago, Egypt and Nigeria, adding up to 0.07 Tcf, or 0.21 Bcfd.

Table 17 LNG import terminals in Mexico [44]

Location	**Operational**	**Bcfd**	**Comments**
East Coast			
Altamira, Tamaulipas	Sept 2006	0.7	Shell/Total/Mitsui
West Coast			

[40] NEB Table A2.1: Demand, Reference Case and Continuing Trends, Canada. 1104 PJ = 1 Tcf
[41] Canada projections from early release AEO2009, data received from Joe Benechhe, own aggregations
[42] http://www.iea.org/Textbase/stats/gasdata.asp?COUNTRY_CODE=MX. 1104,000 TJ = 1 Tcf
[43] BP Statistics 2008
[44] http://www.ferc.gov/industries/lng.asp , Oct 10, 2008

Energía Costa Azul, Baja California	Plan: 2008	1.0	Sempra[45]
Baja California Expansion		1.5	Energy Costa Azul/Sempra/Expansion
Manzanillo	Plan: 2011	0.5	KMS GNL de Manzanillo[46]
Total scheduled		3	

4.2 Assumptions AEO2008

Canadian and Mexican consumption as well as Mexican production are set exogenously, according to EIAs International Energy Outlook 2007 projections.

Canadian consumption is assumed to grow from 3.4 Tcf in 2005 to 5.0 Tcf in 2030.
Production in Canada East is assumed to grow from 0.15 Tcf in 2005 to 0.71 Tcf in 2030

The factors that are determined endogenously in NGTDM are production in Western Canada, LNG regasification terminal investments and operations, and pipeline expansions and operations.

The Canadian recoverable reserves are assumed to be 70 Tcf, for coalbed methane, and conventional WCSB: 92 Tcf[47], totaling 162 Tcf.

In the AEO 2008 if put in place, the pipeline Mackenzie-Alberta would have an initial capacity of 1.1 Bcf per day for an earliest start year 2014, and an expansion potential of 58%. This pipeline will only be built if wellhead prices are higher than a trigger price for a given period of time.

4.3 Discussion

Previously there was a mismatch between NEB and EIA outlook for the US Canadian gas trade projections. The EIA projected imports were higher than the NEB projected exports, and LNG imports would have been the likely option to fill the gap. Since in the AEO2009 the US domestic production grows so much more, the trade balance with Canada is closer to the NEB projection.

Table 18 below shows the volumes of gas available for pipeline exports from Canada to the US based on the Canadian NEBs projections, as well as the US pipeline imports from EIAs AEO 2008. At a first glance these figures seem to be in line with each other. However when looking into the underlying assumptions, we see that these differ quite a lot, and it is somewhat surprising that these projected totals actually match.

Table 18 (Tcf)

Tcf	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
Production (NEB)	6.2	6.2	5.8	5.5	4.9	4.4	3.8

45 http://www.sempralng.com/Pages/Terminals/Energia/default.htm
46 http://www.mitsui.co.jp/en/release/2008/1187660_2849.html, 14 million cubic meters per day
47 To capture the impact of potential resources in tight formations a yearly increase in WCSB resources of +1.5% is applied.

Tcf	2000	2005	2010	2015	2020	2025	2030
LNG imports (NEB)	0.0	0.0	0.2	0.5	0.8	0.8	1.1
Secondary demand (NEB) → this excludes NG for power, however that is low in CAN	3.5	3.6	3.8	4.1	4.3	4.4	4.5
Available for Exports (NEB)	**2.8**	**2.6**	**2.1**	**1.9**	**1.4**	**0.8**	**0.3**
US TOTAL pipeline imports (AEO)	3.5	3.3	2.8	2.2	1.4	1.1	0.9
US LNG imports (AEO)		0.6	1.2	2.1	2.4	2.6	2.8
Total US Net Imports		3.6	3.8	4.0	3.6	3.3	3.2

First of all, the projections for demand growth differ significantly. Both starting with a figure of 3.6 Tcf in 2005 [48] the by EIA projected demand in Canada is 0.7 Tcf higher than the NEB figure. (5.2 vs. 4.5). [*This was actually 5.2 vs 5.0, so very similar*]

Second, in the NEB projections, the Mackenzie delta production amounts to 0.7 Tcf in 2030, whereas in the AEO 2008 projections the pipeline needed to transport that gas is never built. [*AEO 2009 puts it in in 2030]*

DISCUSSED AND ADDRESSED [The gas trade with Mexico could change the 1.4 Tcf difference mentioned before, however probably accounting for a rather small fraction. Of the currently developed LNG terminals in Baja California, Mexico, 0.5 bcfd or about 0.2 Tcf is destined for the US market. Since other Mexican regions may be net importers from US pipeline gas, the projected natural gas trade balance between US and Mexico in 2030 is not clear to me. [Unless the part destined for the US market is included in the LNG imports of the EIA projections. Similar for Canadian LNG imports destined for US markets.]
Joe or Andy: outputs regarding production and LNG imports for Canada and LNG and pipeline Mexico]

Note: The DOE (with ICF) is developing an international gas market model[49]. The model has been used in the EMF 23 studies and to provide seasonal LNG supply curves, see the section on LNG. Model documentation is not available yet, but is expected early 2009.

4.4 Recommendations

For the AEO the detailed developments in Mexico and Canada are not as relevant as the projections for trade balances. The EIA projections for the trade balance with Canada are in line with the projections by the NEB.
ADDRESSED *The trade balance with Mexico is not completely clear to me yet and it is advised to contact one of the EIA people for some further clarification. At this point for the AEO projections I see no reason to change the underlying assumptions for the Canadian or Mexican projections.*

[48] This implies that the figure to use from Table 15 is the value for Secondary demand NO. Should Be Primary Demand
[49] http://www.stanford.edu/group/EMF/projects/emf23/JanDocs/INGM.pdf

SOME OF THESE HAVE BEEN OVERTAKEN BY THE SHALE DEVELOPMENTS However if RFF will implement some of the other recommendations in this report, a consequence may be that wellhead prices rise high enough to trigger the pipeline investment in the Mackenzie pipeline, which could bring an additional 0.4 Tcf (0.6 including the expansion) to the Canadian and possibly US market. And higher wellhead prices might also trigger higher LNG import capacities in the Canadian market. This could significantly increase projected Canadian supplies to the US market relative to the current reference projection of about 0.3 Tcf in 2030.

ADDRESSED, EXCLUDE *To bring EIA projections in line with NEB projections, consumption growth should be revised downward with about 50%, and production in Western Canada with about 20%. However, before giving a final recommendation some discussion is needed with EIA people.*

5 Liquefied Natural Gas

LNG will become an important source of US natural gas supplies.

NOT ANYMORE IN AEO 2009. The modeling LNG has been revised. The International Gas Model has provided seasonal LNG supply curves that are used as input in NEMS.

5.1 Projections

The AEO 2008 projects that by 2030 about 1/8 of total consumption will be covered through LNG imports, or 7/8 of total natural gas imports. Net LNG imports grow from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030[50]. AEO 2009 projects near self-sufficiency in 2030.

Table 19 AEO 2008 Natural Gas Imports (Tcf)

AEO	PAST		AEO 2008				AEO 2009			
	2000	2005	2008	2010	2020	2030	2008	2010	2020	2030
Net Imports	**3.5**	**3.6**	**3.8**	**3.8**	**3.6**	**3.2**	**2.9**	**2.5**	**1.9**	**0.7**
Pipeline	3.4	3.0	2.9	2.6	1.2	0.3	2.6	2.0	0.5	-0.2
LNG	0.2	0.6	0.9	1.2	2.4	2.8	0.3	0.5	1.4	0.8
% of supply										
import	15%	17%	16%	16%	15%	14%	12%	11%	8%	3%
LNG	1%	3%	4%	5%	10%	12%	1%	2%	6%	3%

The total capacity of U.S. LNG receiving terminals increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the reference case (with no further increase through 2030). In both AEO 2008 and 2009.

5.2 Assumptions

AEO assumes that there are four existing LNG import facilities as of 2004. There can potentially be seven new LNG receiving terminals, plus one for the Bahamas, one in Western Canada, one in Eastern Canada and one in Western Mexico. All terminals that are currently under

[50] Exports from Alaska to Japan are subtracted from gross imports to arrive at net. Alaskan LNG will be phased out.

construction are forced into the model. Any additional terminals are determined endogenously by the model.
There are five new re-gasification terminals under construction as of December 2008, four at the Gulf Coast and one in New England.

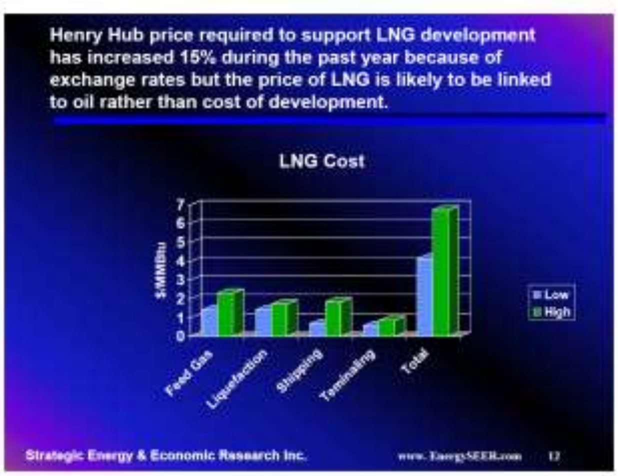
[DISCUSSED, not up to date anymore] LNG supplies are converted into peak/off peak flows based on historical data.

LNG terminal trigger prices are in the $3.39-5.02 ($2005) range for the US, $5.43 in Baja California, Mexico, $4.07 for expansion of the Eastern Canadian facility and $5.48 for – new – construction in Western Canada. These LNG trigger prices are adjusted by ‘a market price adjustment factor representing the difference between the world market price for LNG and the cost to bring it to the US markets’

Table 20 estimated LNG cost components ($2005/mcf)

	Low	High
production	0.39	1.75
liquefaction	1.53	1.53
shipping	0.40	2.21
re-gasification	0.40	1.11
risk premium	0.63	2.00
adjustment factor	?	?

Liquefaction costs have been adjusted upward to $2.39 to reflect higher prices for commodities such as steel.



5.3 Discussion

The AEO 2008 projected total net imports in 2030 are between 1.7 and 12.4 Tcf lower than all other projections. The projected LNG imports in 2030 alone are between 1.4 and 9.8 Tcf lower than other projections. According to AEO 2008 just 13% of consumption would be covered b y

LNG in 2030, whereas the highest share among other projections reaches 40% [51]. It is interesting to note that the projected LNG imports in the low oil price high LNG availability sensitivity case of 4.5 Tcf are in the middle of the range of all other projections.

[DISCUSSED, not up to date anymore] According to FERC the US currently have six active terminals, but AEO documents only five. The total capacity of about 2.4 Tcf/y is also a lot higher than the 1.5 Tcf documented in AEO.

Where	**AEO 2008**	**AEO 2009**	**Bcfd**	**Bcfd**	
Everett, MA	X	exists	1.035	1.0	
Cove Point, MD	X	exists	1.0	1.0	
Elba Island, GA	X	exists	1.2	1.2	
Lake Charles, LA	X	exists	2.1	2.1	
Gulf Gateway	X	exists	0.5	0.5	
Northeast Gateway	-	2008	0.8	0.8	
Freeport		2008		1.5	
Sabine Pass		2009		2.6	
Cameron at Hackberry				1.5	
Golden Pass				2.0	
			6.635	14.2	14.2 → 5.2 Tcf/y

The assessment for liquefaction operational costs leads to a cost of $1.54/mcf ($2005). In the analysis a remark is made that following an estimated learning curve would lead to too large cost improvements and an adjusted measure is proposed. However the original improvement was about 10% by 2030, and the applied eventual cost improvement is just a few percent point lower, so it is not clear to me why the values needed to be adjusted. In comparison with the technological progress assumptions in the production module (OGSM), the assumed technological progress in the LNG sector is rather modest.

In recent years the investment costs for liquefaction facilities have grown tremendously, e.g. due to increases in steel prices[52]. To address this the liquefaction costs have been revised to $2.39, about 50% higher than $1.54 ($2005). The question is: will these high costs remain, or will they come down again? For other commodities, such as oil, the assumed prices in the AEO will come down in the mid term. Why not the LNG investment costs?

[51] Between the ‘comparison with other projections’ in AEO and the EMF 23 final report. www.stanford.edu/group/EMF/projects/projectemf23.htm

[52] The needed amounts of steel for LNG terminals and long distance pipelines are enormous, several millions of tons. A re-gasification terminal needs … for a capacity of …. The American Iron and Steel Institute estimates 3 to 5 million tons of steel; http://ncseonline.org/NLE/CRSreports/07Apr/RL33716.pdf the Bureau of Land Management, estimates 6-million tons of steel, www.blm.gov/pgdata/etc/medialib/blm/ak/aktest/rac.Par.33195.File.dat/2005,%20Feb.8-9%20Minutes.doc www.industrialheating.com : Remember that, as a rule of thumb, **pipelines** require a pumping station each sixty miles, gas extraction platforms use 2.4 thousands tons of steel, a gas process plant consumes 12.5 thousand tons of steel products plus pipe and pumps. www.steelguru.com 2nd West East pipeline to consume 4.4 million tonnes of steel

The costs for re-gasification seem high, mainly so when considering the risk-premiums that have been added. When considering the willingness of market players such as Cheniere Energy to invest in new re-gasification capacity it seems that the AEO assumptions are more limiting then necessary[53].

The ships used in LNG shipping are becoming bigger and bigger and have significant economies of scale. Of course the steel prices have an impact here as well, but cost reductions seem still very well possible due to technological progress, economies of scale and decreasing commodity prices[54].

When combining the whole set of assumptions – capital investment costs for liquefaction, contingencies and risk premiums for re-gasification, risk premiums in the discount rate, modest technological progress and the market price adjustment factor (for which I have not found the values) and comparing the result with e.g. market data from BG[55] all seem to make LNG very expensive. A couple of years ago EIA project Qatari LNG to be competitive in the US market at wellhead prices of around $3.5. With the current assumptions this is 50%-100% higher, when taking the lowest re-gasification and shipping cost assumptions.

There is a remark about how legislation to enhance re-gasification terminal investments are implemented through adjusting model parameters. It is not clear to me what this encompasses.

[DISCUSSED, not up to date anymore] LNG supplies are converted into peak/off peak based on historical data. There is debate that due to competition with Europe in the Atlantic Basin LNG might not be available, or only at much higher prices in the winter season, which would possibly make LNG imports a seasonal matter[56]. There are even some experts that suggest that the US might store still liquefied LNG in summer and re-export to Europe in winter. All this has consequences for the storage market as well. It might be considered to have seasonally different LNG cost-supply curves.

In AEO2009 EIA has completely changed the representation of LNG. LNG supplies are represented by season from EIA's International Natural Gas Model

5.4 Conclusions and Recommendations

[DISCUSSED, there was some confirmation of the possibly relatively high cost assumptions for LNG, however due to revising the LNG modeling this section is not up to date anymore] *It seems that the assumptions for LNG costs are in the more pessimistic part of the spectrum of realistic assumptions. Since production and consumption assumptions are generally more positive, LNG becomes less competitive and the AEO projections create lower LNG shares and lower projected import dependency relative to other projections.*

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53 www.cheniere.com/lng_terminals/terminals.shtml
54 See also www.feem.it/NR/rdonlyres/0EA6026C-348B-46C4-B58D-9FA972A7C504/1261/11404.pdf
55 www.bg-group.com/OurBusiness/BusinessSegments/Documents/BG_LNGfactsheets2008.pdf
56 See e.g. www.ferc.gov/EventCalendar/Files/20071107073729-Patricia-Outtrim.pdf

It is not clear why some sectors of the market should have relatively pessimistic assumptions when for others the assumptions are rather optimistic. Implicitly the assumptions favor domestic and Canadians supply over LNG imports to fulfill gas demand in the long run even when this economically may not be warranted.

<u>*[Would need to look into International Energy Model documentation. Not in the scope of this report]*</u> *The actual investments in re-gasification capacity in the US and additions in liquefaction capacity worldwide and the projections by many other institutions indicate a larger role for LNG in future natural gas trade then the AEO suggests. Prices for steel and other commodities have come done rapidly in the last months of 2008, indicating that the record prices in the summer of 2008 were record prices indeed. The current global economic downturn (late 2008, early 2009) will relieve the construction capacity and resource constraints responsible for the LNG investment cost increases a few years back*.

It seems warranted to reduce the cost estimates by undoing the previous upward adjustments for LNG investments, which would reduce the per mcf investment costs with almost $1. The fixed risk-premiums for re-gasification locations seem high, but if they are justifiable for some areas, e.g. the North East, it might be an option to only allow higher expansions with (significantly) lower risk premiums in regions where actual developments are taking place: East Canada, the Gulf Coast; and possibly the northern part of the Pacific Coast.

<u>*[DISCUSSED AND ADDRESSED]*</u> *The question about the sixth missing re-gasification terminal can probably be answered right away by one of the EIA people.*

<u>*Would need to look into International Energy Model*</u> *Technological progress and economies of scale assumptions for LNG, shipping and re-gasification could be allowed for or revised. Although the impact would be modest relative to the previous recommendations, they could add up to another 10% supply cost reduction, or about $0.50 in the long run.*

[<u>International Energy Model provides seasonal LNG supply curves</u>] The impact of the fixed assignment of shares of LNG imports to seasons is not immediately obvious. Especially when the share of LNG would be a lot higher, these shares impact the use of storage and pipelines. Some discussion with EIA people might shed some more light on this.

6 Pipelines, Distribution and Storage

Pipelines, distribution networks and storage play a relatively minor in the AEO projections. High pressure interstate, intrastate and local distribution pipelines are all represented in the NGTDM. How do pipeline, storage and distribution tariffs and the expansion costs affect the end-user prices, and how do consumptions respond to them in the short and long run for given price-elasticities?

6.1 Projections

Mostly for the power generation sector, and slightly for the industrial sector and transport sector, pipeline rates are projected to decrease. For the other sectors, residential, commercial the mark-up for transmission and distribution services is projected to increase.

Table 21 Delivered prices and transmission and distribution margins[57]

	2000	2005	2010	2015	2020	2025	2030
Transmission & Distribution Margins							
Residential	4.8	5.3	6.1	6.1	6.2	6.4	6.6
Commercial	3.5	3.9	4.5	4.5	4.7	4.9	5.1
Industrial	0.7	0.7	1.0	0.9	0.9	0.8	0.8
Electric Power	0.9	0.7	0.7	0.7	0.6	0.5	0.4
Transportation	6.2	7.0	7.6	7.3	7.0	6.7	6.5
Average	**2.1**	**2.3**	**2.5**	**2.6**	**2.7**	**2.8**	**2.9**
Delivered Prices							
Residential	9.1	13.2	12.5	11.5	11.7	12.3	13.3
Commercial	7.8	11.9	10.9	10.0	10.2	10.8	11.8
Industrial	5.0	8.6	7.4	6.3	6.4	6.8	7.5
Electric Power	5.1	8.7	7.2	6.1	6.1	6.4	7.1
Transportation	10.4	15.0	14.0	12.7	12.5	12.7	13.2
Average	**6.4**	**10.2**	**9.0**	**8.0**	**8.2**	**8.7**	**9.6**
Average Source Price	**4.3**	**8.0**	**6.5**	**5.5**	**5.5**	**5.9**	**6.7**

For storage I have found no projections for the use of it. Since projections are annual, this may be of minor importance. [Projections are annual]

The Alaska natural gas pipeline was briefly addressed in the section on production. In the reference projection the pipeline is put in place, with a capacity of 3.9 Bcfd. The Mackenzie pipeline is not built in the reference case. See also section 4.1.1

6.2 Assumptions

Announced expansions of pipelines and storage capacity highly likely to be in place in the first two years of the time horizon are used as constraints for flows and injected and extracted storage volumes. In the years thereafter capacity is added when consumption growth and price levels are high enough. Costs for expansions are rolled into the revenue requirements of market players for later years.

Distribution tariffs are based on historical data, i.e. the differences between regional delivered prices and citygate prices, and changes in consumption levels.

Pipeline and storage tariffs are based on the revenue requirements of the owning companies. Rates include fixed rates and volume dependent rates, for existing and expanded capacity.

New pipelines, from Alaska and from the Mackenzie delta to Alberta, will come online after a "high enough" gas price in lower 48 for a number of years[58], both in the past and in the future.

[57] Source: aeo2008/d030208f.xls for the reference scenario, Table 13
[58] Actually an adjusted weighted average price for five years is used. If interested in details, see the documentation.

The Alaskan pipeline could be built earliest in 2020, the Mackenzie pipeline in 2014 earliest. Expansions to the pipelines can happen after an additional increase in gas prices.

Pipeline and storage capacity are based on 30% colder than average winter.

Discount rates for investments in new pipelines are based on AA bond rates plus a mark-up, resulting in discount rates of around 13-14%.

All AEO2008 cases assume that there are no restrictions, such as public opposition, regarding the expansion of transmission and distribution capacity

6.2.1 The Alaskan Pipeline System[59]

The Alaska natural gas pipeline was briefly addressed in the section on production. Alaskan production is based of Alaskan consumption, the pipeline to Alberta and a GTL[60] facility. The initial trigger price for the Alaskan Pipeline is ~ $4.37/Mcf ($2006), and the expansion trigger, that would add an expansion of 22% (on top of the 3.9 Bcfd) is another $1.94 higher, i.e. ~$6.30.

The federal loan guarantees for the Alaskan pipeline are implemented through a higher debt portion and lower discount rates.

6.2.2 The Mackenzie Delta Pipeline (Canada)

The Mackenzie natural gas pipeline was briefly addressed in the section on Canada. The initial trigger price is not given in the documentation, but the provided information suggest that it is about $1.50 higher than the trigger for the Alaskan pipeline, i.e. close to $6/Mcf ($2006).

6.3 Discussion

The average mark-ups on wellhead prices to deliver gas to the door of the consumer slightly increases over time. However there are differences among sectors. For residential and commercial sectors the assumptions for increased efficiency reduces the used volume per location, therefore the capital cost per unit of transported gas increase. For industry and power there is an other trend. More factories and power generators will be immediately connected to transmission pipelines, avoiding local distribution costs, and resulting in lower mark-ups.

The earliest year for the Alaskan pipeline to be built is 2020, and it kicks in immediately in the projections. The expansion potential is fixed to 22%, and needs a higher trigger price, almost $2 higher. Expansion are generally much cheaper than the initial investment, and the initial capacity costs could be divided over a bigger flow, so it is not clear to me why the trigger price for the expansion needs to be that much higher.

The trigger price for the Mackenzie pipeline is a lot higher than that of the Alaskan pipeline. It could come on stream in 2014 earliest, but it does not in the AEO projections. However it does in the Canadian NEB reference projections.

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[59] For details, see *Assumptions to the Energy Outlook 2008*. Table 55. page 116.
[60] Gas To Liquids

For some reason the trigger price for an expansion of the Mackenzie pipeline is only $0.34 cents higher, much lower than the $1.94/mcf for the Alaskan pipeline. But since the initial trigger price is quite higher than that for the Alaskan pipeline (it has no loan guarantee), the Mackenzie pipeline is never built. I would be interested to know the actual trigger price for the Mackenzie pipeline, and some clarification of the differences between the trigger prices for both pipeline. (Beside the assumptions stated in the document.) NEB analyses a total of three cases. It is interesting to note that in two of the three cases the Mackenzie pipeline would be in place, and in the third one it would not, because of high availability of LNG supplies. So either the Mackenzie pipeline, or high LNG supplies. The AEO has neither of them.

6.3.1 Conclusions and Recommendations

The peak demand season in NGTDM is December-March. Other models have other seasonal demand patterns, for example more seasons. To get an indication for if a third season should be considered, look at the monthly consumption for 2006 and 2007 (in Table 22 below) and the average consumptions for the two seasons, also based on the 2006 and 2007 data.

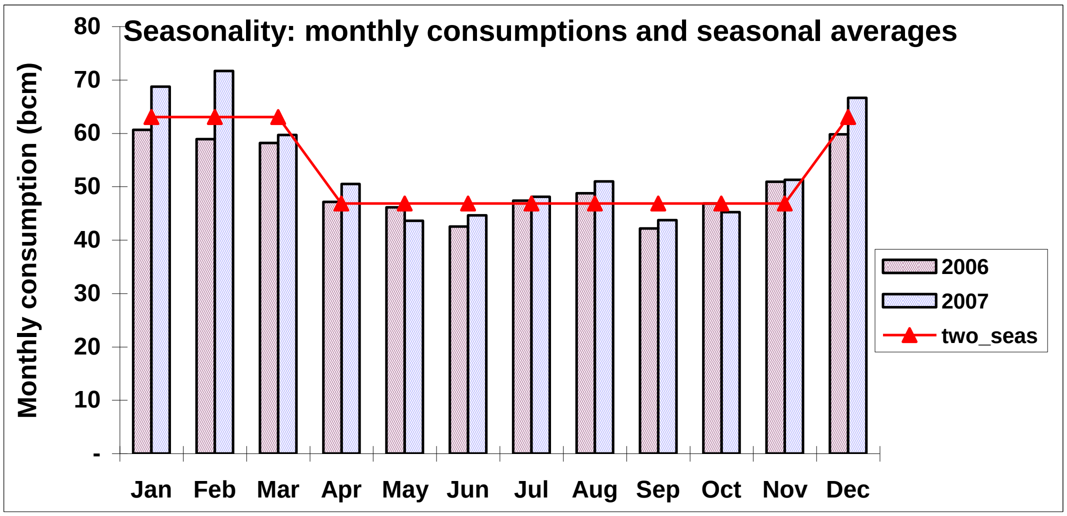

Table 22 Seasonality: monthly consumption and seasonal averages 2006-2007[61]

Based on this sample it seems that two demand seasons is a very defendable choice.

6.4 Conclusions and Recommendations

Transport, distribution and storage mark-ups are a significant part of the delivered prices for several of the sectors, but not for all. For example for the residential and transport sectors the mark-ups are fifty percent of the delivered price (in 2030), but only six percent for power generation. The way how the rates are determined is relatively straightforward and very well defendable. However due to underlying assumptions the delivered amount of natural gas per consuming site will decrease over time. As was discussed in previous sections, the consumption projections seem to be at the low end of the realistic spectrum. If some of the suggested recommendations are implemented we can expect to see higher wellhead prices and higher

[61] http://www.iea.org/Textbase/stats/surveys/archives.asp, TABLE 1.1: Natural Gas Balances in OECD Regions and Countries

consumption values. However mark-ups will be lower, dampening the increase in the delivered prices.

It may be that adjusted assumptions may lead to high enough wellhead prices to trigger the investment in the Mackenzie pipeline in the model. However a reassessment of the underlying assumptions could maybe lead to a lower trigger price. [Need some input from EIA] See also the discussion in the section on Canada, considering the very different underlying assumptions resulting in quite similar AEO imports from Canada (slightly higher) than the NEB export projections from Canada.

For the Alaskan pipeline, it seems that a lower trigger price for the expansion could be justified. Also the capacities could be reconsidered based on the recent gas hydrates reserves assessment

7 AEO 2008 & 2009 Projections for selected years[62]

Table 23 Supply

	PAST		AEO 2008				AEO 2009			
	2000	2005	2008	2010	2020	2030	2008	2010	2020	2030
Production										
Dry Production	19.2	18.1	19.2	19.3	19.7	19.4	20.5	20.3	21.4	23.6
Supplemental	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Net Imports	**3.5**	**3.6**	**3.8**	**3.8**	**3.6**	**3.2**	**2.9**	**2.5**	**1.9**	**0.7**
Pipeline	3.4	3.0	2.9	2.6	1.2	0.3	2.6	2.0	0.5	-0.2
LNG	0.2	0.6	0.9	1.2	2.4	2.8	0.3	0.5	1.4	0.8
Total Supply	**22.8**	**21.7**	**23.1**	**23.2**	**23.3**	**22.7**	**23.5**	**22.8**	**23.3**	**24.4**
Dry Production										
US Total	19.2	18.1	19.2	19.3	19.7	19.4	20.5	20.3	21.4	23.6
Lower 48 Onshore	13.6	14.3	15.5	15.3	14.2	14.0	17.0	16.7	16.1	16.8
Associated	1.8	1.4	1.4	1.4	1.3	1.2	1.4	1.4	1.4	1.3
Non-Associated	11.8	12.9	14.1	13.9	12.8	12.8	15.6	15.3	14.7	15.4
Conventional	6.1	4.9	5.1	4.8	3.5	3.2	5.2	4.7	3.4	2.2
Unconventional	5.7	8.0	9.0	9.0	9.4	9.5	10.4	10.6	11.3	13.2
Lower 48 Offshore	5.2	3.3	3.3	3.6	4.3	3.5	3.2	3.3	4.2	4.9
Associated	1.1	0.7	0.6	0.7	1.0	0.8	0.6	0.7	1.0	1.1
Non-Associated	4.1	2.7	2.7	2.9	3.3	2.7	2.6	2.5	3.2	3.8
Alaska	0.4	0.5	0.4	0.4	1.2	2.0	0.4	0.4	1.1	2.0
Unconventional	**5.7**	**8.0**	**9.0**	**9.0**	**9.4**	**9.5**	**10.4**	**10.6**	**11.3**	**13.2**
Gas Shale	0.4	0.8	1.1	1.2	1.8	2.2	1.6	2.3	3.0	4.1
Coalbed Methane	1.5	1.8	1.8	1.8	1.7	1.8	2.0	1.8	1.8	2.0
Tight Gas	3.8	5.4	6.1	6.0	5.9	5.5	6.8	6.5	6.6	7.1

Table 24 Demand

[62] Sources: ftp://ftp.eia.doe.gov/pub/oiaf/aeo/aeo2008.zip: aeo2008.0302f.xls, Tables 13 and 14., www.eia.doe.gov/oiaf/aeo/aeoref_tab.html

	PAST		AEO 2008				AEO 2009			
	2000	2005	2008	2010	2020	2030	2008	2010	2020	2030
Total Supply	**22.8**	**21.7**	**23.1**	**23.2**	**23.3**	**22.7**	**23.5**	**22.8**	**23.3**	**24.4**
Cons by Sector										
Residential	5.0	4.8	4.8	4.8	5.1	5.2	4.9	4.8	5.0	4.9
Commercial	3.2	3.0	3.1	3.0	3.4	3.7	3.1	3.1	3.3	3.4
Industrial	8.1	6.6	6.6	7.0	6.9	6.9	6.7	6.4	6.6	6.8
Electric Power	5.2	5.8	6.8	6.7	5.9	5.0	6.8	6.3	6.5	7.0
Transportation	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1
Pipeline Fuel	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.6	0.7	0.7
Lease & Plant Fuel	1.2	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.4
Total	**23.3**	**22.0**	**23.1**	**23.2**	**23.3**	**22.7**	**23.4**	**22.5**	**23.4**	**24.4**
Discrepancy	**-0.5**	**-0.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.4**	**0.0**	**0.0**

Table 25 Prices

Note that AEO 2009 prices are in $2007 and AEO 2008 in $2006. Year-on-year inflation: 2.8%. The 2005 values are reported past figures; so is 2008 for AEO2009, but not for AEO 2008.

	PAST	AEO2008					AEO2009				
	2000	2005	2008	2010	2020	2030	2005	2008	2010	2020	2030
(USD per mmBtu)											
Henry Hub Spot	5.2	8.9	7.2	6.9	5.9	7.2	9.2	9.0	6.5	7.4	9.2
Average Lower 48 Wellhead	4.2	7.6	6.4	6.2	5.3	6.4	7.8	7.8	5.8	6.6	8.2
(USD per mcf)											
Average Lower 48 Wellhead	4.3	7.8	6.6	6.3	5.4	6.6	8.1	8.0	5.9	6.8	8.4
Delivered Prices											
Residential	9.3	13.2	13.0	12.5	11.7	13.3	13.4	13.4	12.3	12.9	14.7
Commercial	8.0	11.9	11.4	10.9	10.2	11.8	12.0	11.8	10.7	11.4	13.3
Industrial	5.1	8.6	7.6	7.4	6.4	7.5	8.9	9.2	7.0	7.7	9.3
Electric Power	5.3	8.7	7.4	7.2	6.1	7.1	8.9	9.4	6.7	7.3	8.9
Transportation	10.7	15.0	14.2	14.0	12.5	13.2	15.3	17.5	15.2	15.3	16.7
Average	**6.6**	**10.2**	**9.3**	**9.0**	**8.2**	**9.6**	**10.4**	**10.6**	**8.7**	**9.4**	**11.0**
Average Import	4.7	**8.4**	**7.3**	**7.0**	**5.9**	**7.0**	8.6	9.6	7.2	6.9	8.9
Average Source	4.4	**8.0**	**6.7**	**6.5**	**5.5**	**6.7**	8.2	8.3	6.1	6.8	8.4
Transm & Distrib											
Residential	5.0	5.3	6.3	6.1	6.2	6.6	5.3	5.1	6.2	6.1	6.3
Commercial	3.6	3.9	4.7	4.4	4.7	5.1	3.8	3.6	4.6	4.7	4.9
Industrial	0.7	0.7	0.9	1.0	0.9	0.8	0.7	1.0	0.9	0.9	0.9
Electric Power	0.9	0.7	0.7	0.7	0.6	0.4	0.7	1.2	0.6	0.6	0.5
Transportation	6.3	7.0	7.5	7.5	7.0	6.5	7.2	9.2	9.1	8.6	8.3
Average	2.2	**2.3**	**2.6**	**2.5**	**2.7**	**2.9**	2.3	2.4	2.6	2.6	2.6

8 Green House Gasses and other emissions

NEMS includes (impacts and costs for compliance with legislation for) all combustion related CO_2 emissions, and SO2, NOx and mercury from power generation. CO_2 emissions are calculated using CO_2 coefficients.

This sections provides a, mostly tabular, overview of reference projections and some assumptions to show what AEO incorporated regarding emissions.

8.1 Projections

Table 26 Emissions [63]

	2000	2005	2010	2015	2020	2025	2030
Natural Gas CO_2 emissions (Million metric tons)	1,240	1,193	1,256	1,279	1,262	1,245	1,231
Total energy related CO2 emissions	5,847	5,982	6,011	6,226	6,384	6,571	6,851
NG CO_2 emissions as percentage of total energy related	21.2%	19.9%	20.9%	20.5%	19.8%	18.9%	18.0%
Non-Energy GHG Emissions	1,131	1,199	1,171	1,251	1,344	1,456	1,590

Table 27 Electric Power Sector Emissions [64]

	2000	2005	2010	2015	2020	2025	2030
Sulfur Dioxide (million tons)	11.2	10.2	6.4	4.7	3.8	3.7	3.7
Nitrogen Oxide (million tons)	5.1	3.6	2.3	2.1	2.1	2.1	2.2
Mercury (tons)	52.8	51.7	37.2	24.8	19.2	16.9	14.9

8.2 Assumptions

Table 28 Natural gas CO_2 emission factors (million metric tons CO_2-eq per Q Btu) [65]

	CO_2 Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Used as Fuel	53.06	1.000	53.06
Used as Feedstocks	53.06	0.517	27.44

Some regulation related to electric power production

- In the coal module: sulfur and mercury allowance costs
- Clean Air Act Amendments of 1990 and Clean Air Interstate Rule regulation for SO_2 and NO_x,[66]

[63] Table 2, details in Table 17
[64] Table 8
[65] Assumptions to the Annual Energy Outlook 2008, page 10, Table 2. Carbon Dioxide Emission Factors

- Power Plant Mercury Emissions Assumptions[67]
- Scrubbers to reduce particulate emissions[68]
- CAAA90: SO_2 and NO_x cap and trade
- Clean Air Mercury Rule: a cap-and-trade program

9 Legislation

This section provides an extensive but non-exhaustive tabular overview of the implemented regulations to give an insight in the policy levers available in NEMS/NGTDM, and reasons why sometimes policy is not implemented.

AEO 2008 includes all current legislation and environmental regulations as of December 31, 2007. Examples are

- The Energy Independence and Security Act of 2007 [EISA2007]
- The Energy Policy Acts of 2005 [EPACT2005]
- The Working Families Tax Relief Act of 2004
- The American Jobs Creation Act of 2004

and the costs of compliance for regulations such as

- The Clean Air Interstate Rule, 2005
- Clean Air Mercury Rule [CAMR] 2005
- The new stationary diesel regulations [EPA] July 2006

Any pending or proposed (sections of) legislation, regulations, or standards for which the funding or implementing regulation is not in place yet, are not reflected in NEMS

Table 9-1 Implemented Legislation in OGSM

Legislation	**implementation**	**immediate impact**
Royalty suspension	Royalty rates based on water depth	$$ (bbl)
Inventory oil and gas resources	technically recoverable resource volumes	bbl ($$)
Termination of open access for LNG; allow market based rates	lower risk premiums in LNG Regas investment decision	$$
Jurisdiction offshore LNG Regas from FERC to other regulators	lower risk premiums in LNG Regas investment decision	$$
Nonconventional fuel production credit	Expired, but still implicitly reflected in historic data	$$

Table 9-2 Implemented Legislation in NGTDM

Legislation	**implementation**	**immediate impact**
Alaska NG pipeline not to enter	Adjusted cost estimate, adjusted tariff	$$

66 Assumptions to the Annual Energy Outlook 2008, page 86/87
67 page 88, 89
68 Page 89

Legislation	implementation	immediate impact
CAN north of 68 degrees latitude: federal loan guarantees	calculation	
Alaskan pipeline extended cost-of-investment recovery period	Adjusted tariff calculation, lower gas processing charges	$$
Pipeline safety	Accelerated maintenance schedules	$$
Pipelines non-discriminatory open access (1985)	Transportation costs based on a regulated rate	$$
Pipelines tariff differentiation	Tariffs can vary with utilization rate, end-use-price-discrimination among market sectors	$$
Storage market based rates if no market power	Tariffs can vary based on market conditions	$$

Table 9-3 Implemented Legislation in Demand Modules[69]

Legislation	implementation	immediate impact
Minimum efficiency standards for appliances and equipment such as aircos, water heaters, …	increased efficiency for technologies???	$$
Building codes	Technology choice parameters	$$
Tax credits for energy efficient equipment	Lower costs	$$
Labeling (i.e., info on products)	Improved efficiency over time	$$
Investment credits	Lower costs	$$
Federal energy management	Lower discount rate for investment decisions	
Several emission related standards for industry	Not, when not related to energy. But e.g. SO2 restriction is not included since not projected to be limiting	
Voluntary energy intensity commitments	Not included since voluntary	
Tax credit for coke ovens	Not included since no impact is expected	
Light vehicle emission standards	Not included, since California and EPA are still arguing over it.	
Fuel economy standards	There seem to be AEO analyst assumptions that standards become even tighter over the years.	
Federal tax incentives for hybrid cars and other	lower costs	
State tax incentives for hybrid cars and other	Not all included	

[69] Only a subset to show the different policy and regulation levers available

Table 9-4 Implemented Legislation in Power Generation[70]

Legislation	**implementation**	**immediate impact**
CAAA90 SO2 limit	SO2 cap and trade is explicitly modeled	$$/GHG
CAAA90 NOX limit	adjusted emissions and costs for boilers to comply	$$/GHG
summer season NOX cap	NOX cap and trade explicitly modeled	$$/GHG
ozone, fine particulates	Not yet, legislation in progress, compliance should happen 2009-2014	
Investment tax credits	incorporated	
Public Utility Holding Act	competitive behavior among holdings	
Various state laws regarding renewables.	Not included in reference 2008. 2007 has one case focusing on this	

10 Appendix

10.1 Conversion factors

		bcf/d	mcm/d	bcm/y	Tcf/y	Q Btu / y
bcf/d		1	28.3	10.3	0.365	0.38
mcm/d		0.035	1	0.37	0.013	0.01
bcm/y		0.10	2.74	1	0.035	0.04
Tcf/y		0.0027	0.08	0.028	1	1.03
		Mcf	$/Mcf			
kcm		28.3				
$100/kcm			3.53			

1000 bcm ~ 35 Tcf
$100/kcm ~ 3.5 $/Mcf

	cf	cm	MJ
cf	1	0.028	1.1044
cm	35.31	1	39
MJ	0.906	0.026	1

EIA: (JB) Gross Calorific value of natural gas in MJ/cf?
1 Btu = 1055 Joules
1 cf = 1028 Btu (for imports closer to 1025 BTU, exports 1009 BTU)

[70] Only a subset to show the different policy and regulation levers available

10.2 Sensitivity cases

In appendix D of the AEO the results of various sensitivity cases are presented. The factors that are varied among these cases are: economic growth, world oil price and resources, technological progress in the different sectors, power generation costs for the different options, oil and gas costs, LNG supply, Arctic National Wildlife Refuge (ANWR) open for drilling to oil, coal cost, Cooling and Heating Degree Days.

There are several integrated cases, that vary more than one (group of) factors. These include high and low technology cases, high and low energy costs, limited power generation from other than natural gas, limited natural gas supply, and a combined limited case, combining the last two, so both high demand and low supply for natural gas.

10.3 Main Sources

Documents available from EIA websites, such as
http://www.eia.doe.gov/oiaf/aeo/overview/introduction.html,
http://www.eia.doe.gov/bookshelf/models2002/ngtdm.html,
ftp://ftp.eia.doe.gov/pub/oiaf/aeo/,
http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation ,
http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2008).pdf
and several other, referred to in footnotes.

10.4 Other comparisons and evaluations

- AEO 2008 Page 90 Comparison with Other Projections
- Burkhard Schade, Tobias Wiesenthal, 2007, *Comparison of Long-Term World Energy Studies - Assumptions and results from four world energy models*, http://ftp.jrc.es/eur22938en.pdf
- Deutsche Bank 2008, *Commodities Outlook*, www.deutsche-bank.de/presse/en/download/Commodities_outlook_11_jan.pdf