Appendix 8-1. Coal Labor Productivity Assumptions

LABOR PRODUCTIVITY (Short Tons per Miner Hour)

NEMS run aeo2003.d110502c Preliminary

Coal Market Module Region	States	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Northern Appalachia (NA)	PA, OH, MD, WV (North)	4.29	4.21	4.22	4.33	4.43	4.52	4.61	4.70	4.76	4.84	4.91	4.97	5.01	5.05	5.10	5.13
Central Appalachia (CA)	WV (South), KY (East), VA	4.17	3.83	3.96	4.02	4.10	4.18	4.24	4.29	4.34	4.38	4.43	4.45	4.46	4.47	4.47	4.48
Southern Appalachia (SA)	AL, TN	2.79	2.81	2.80	2.81	2.83	2.85	2.86	2.87	2.89	2.90	2.91	2.91	2.92	2.92	2.93	2.93
East Interior (EI)	IL, IN, KY (West), MS	4.72	4.73	4.77	4.80	4.88	4.99	5.06	5.12	5.21	5.26	5.34	5.39	5.48	5.53	5.60	5.68
West Interior (WI)	IA, MO, KS, AR, OK, TX (Bit)	3.58	3.94	3.94	3.92	3.91	3.90	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.90	3.90	3.89
Gulf	TX, LA	9.89	8.85	9.07	9.27	9.46	9.62	9.76	9.88	9.99	10.06	10.10	10.15	10.19	10.23	10.26	10.29
Dakota Lignite (DL)	ND, SD, MT (East)	17.64	17.07	17.43	17.74	18.03	18.28	18.50	18.70	18.89	19.06	19.21	19.35	19.46	19.56	19.66	19.73
Powder & Green River Basins (PG)	WY,	35.86	37.30	38.24	39.12	39.94	40.70	40.95	41.54	42.09	42.61	43.09	43.32	43.32	43.32	43.29	43.29
Rocky	CO, UT	7.66	8.67	9.02	9.38	9.67	9.95	10.20	10.44	10.61	10.75	10.84	10.95	11.07	11.16	11.24	11.34
Southwest (ZN)	NM, AZ	8.01	7.92	8.08	8.27	8.32	8.38	8.39	8.46	8.51	8.55	8.55	8.61	8.62	8.64	8.67	8.67
Northwest (AW)	AK, WA	4.28	4.32	4.34	4.35	4.37	4.38	4.39	4.40	4.40	4.41	4.41	4.41	4.41	4.41	4.41	4.41
Appalachia (NA,CA,SA)		4.10	3.87	3.97	4.04	4.12	4.20	4.26	4.32	4.36	4.41	4.46	4.49	4.50	4.52	4.54	4.55
Interior (EI,WI,GL)		5.81	5.57	5.62	5.62	5.81	5.93	5.99	6.08	6.15	6.22	6.22	6.20	6.28	6.30	6.34	6.39
Northern		33.23	34.43	35.17	36.04	36.81	37.51	37.86	38.50	39.07	39.61	40.18	40.47	40.53	40.57	40.60	40.64
Other West (RM,ZN,AW)		7.44	7.93	8.15	8.43	8.60	8.77	8.92	9.09	9.17	9.28	9.32	9.43	9.56	9.63	9.69	9.78
East of the Mississippi River		4.19	4.00	4.10	4.17	4.25	4.34	4.41	4.46	4.51	4.56	4.61	4.64	4.67	4.69	4.72	4.74
West		17.67	18.34	19.26	19.61	19.78	20.01	20.42	20.94	21.51	21.94	22.82	23.33	23.41	23.63	23.90	24.02
Underground		4.17	4.03	4.20	4.35	4.46	4.58	4.68	4.76	4.80	4.87	4.94	5.02	5.11	5.15	5.20	5.26
Surface		11.05	10.64	10.65	10.80	11.04	11.10	11.30	11.63	11.94	12.30	12.78	13.10	13.37	13.43	13.60	13.69
U.S. Total/Average		7.02	6.85	7.08	7.20	7.39	7.49	7.62	7.80	7.99	8.20	8.47	8.66	8.82	8.87	8.96	9.03

Source: Energy Information Administration, Annual Energy Outlook 2003 (January 2003), Reference Case forecast, National Energy Modeling System run, AEO2003.D110502C.

LABOR PRODUCTIVITY continued (Short Tons per Miner Hour)

NEMS run aeo2003.d110502c

Coal Market Module Region	States	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	AVG 01-05	AVG 01-10	AVG 01-25
Northern Appalachia (NA)	PA, OH, MD, WV (North)	5.17	5.19	5.24	5.27	5.29	5.31	5.33	5.36	5.39	5.42	1.8%	1.7%	1.1%
Central Appalachia (CA)	WV (South), KY (East), VA	4.48	4.49	4.49	4.49	4.50	4.51	4.52	4.53	4.54	4.54	2.2%	1.6%	0.7%
Southern Appalachia (SA)	AL, TN	2.94	2.94	2.93	2.93	2.93	2.92	2.92	2.91	2.91	2.90	0.3%	0.4%	0.1%
East Interior (EI)	IL, IN, KY (West), MS	5.76	5.84	5.91	6.00	6.07	6.15	6.23	6.31	6.40	6.50	1.4%	1.4%	1.3%
West Interior (WI)	IA, MO, KS, AR, OK, TX (Bit)	3.89	3.88	3.89	3.88	3.87	3.86	3.85	3.85	3.84	3.83	-0.3%	-0.1%	-0.1%
Gulf	TX, LA	10.30	10.31	10.32	10.32	10.32	10.32	10.32	10.32	10.32	10.32	2.1%	1.5%	0.6%
Dakota Lignite (DL)	ND, SD, MT (East)	19.81	19.87	19.93	19.97	20.01	20.05	20.09	20.13	20.17	20.21	1.7%	1.3%	0.7%
Powder & Green River Basins (PG)	WY,	43.30	43.31	43.34	43.38	43.45	43.52	43.55	43.59	43.62	43.62	2.2%	1.6%	0.7%
Rocky	CO, UT	11.41	11.50	11.56	11.66	11.75	11.81	11.86	11.93	11.98	12.04	3.5%	2.5%	1.4%
Southwest (ZN)	NM, AZ	8.68	8.69	8.68	8.69	8.69	8.69	8.69	8.69	8.69	8.69	1.4%	0.9%	0.4%
Northwest (AW)	AK, WA	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	0.3%	0.2%	0.1%
Appalachia (NA,CA,SA)		4.57	4.58	4.60	4.61	4.63	4.64	4.66	4.68	4.70	4.70	2.1%	1.6%	0.8%
Interior (EI,WI,GL)		6.48	6.54	6.60	6.64	6.71	6.76	6.82	6.88	6.94	7.03	1.6%	1.2%	1.0%
Northern		40.71	40.78	40.85	40.93	41.04	41.11	41.21	41.29	41.34	41.39	2.2%	1.7%	0.8%
Other		9.82	9.87	9.89	9.98	10.03	10.05	10.10	10.16	10.19	10.25	2.5%	1.8%	1.1%
East of the Mississippi River		4.78	4.80	4.83	4.85	4.87	4.90	4.93	4.96	4.99	5.01	2.1%	1.6%	0.9%
West		24.25	24.52	24.79	25.05	25.32	25.38	25.72	25.85	25.97	26.07	2.2%	2.5%	1.5%
Underground		5.31	5.35	5.40	5.46	5.50	5.56	5.61	5.67	5.72	5.74	3.3%	2.3%	1.5%
Surface		13.90	14.09	14.25	14.45	14.62	14.68	14.91	15.02	15.07	15.16	1.1%	2.1%	1.5%
U.S. Total/Average		9.16	9.28	9.37	9.48	9.60	9.68	9.82	9.91	9.95	9.97	2.2%	2.4%	1.6%

Appendix 8-2. Technical Background Paper on the Development of Natural Gas Supply Curves for EPA Base Case 2004, v.2.1.9

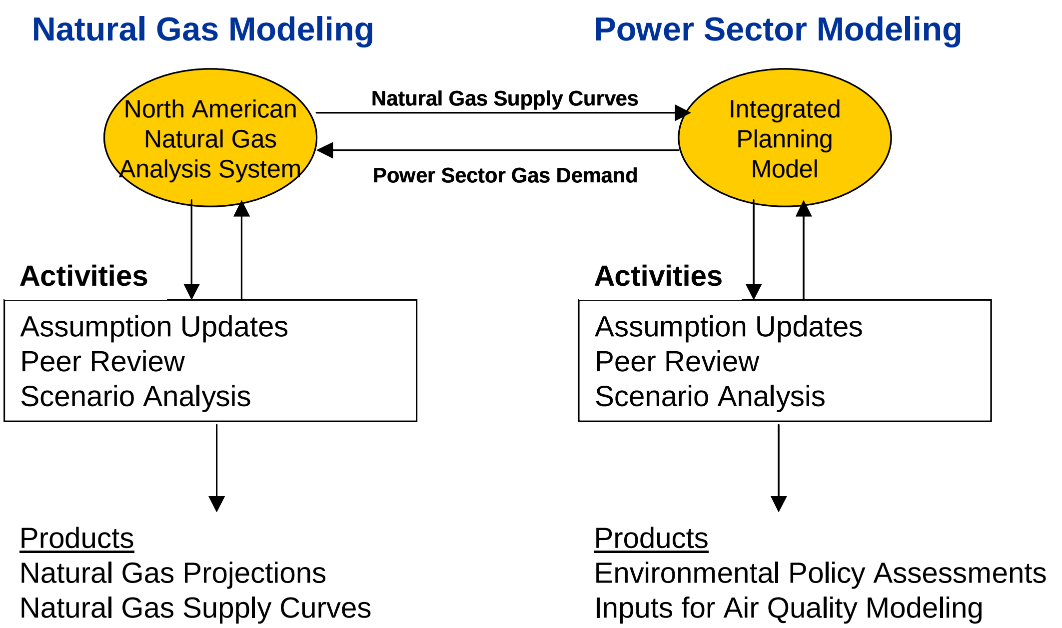
Prepared by ICF Consulting, Inc.

1. Introduction
2. Brief Synopsis of NANGAS
3. Resources Data and Reservoir Description
4. Treatment of Frontier Resources
5. Natural gas Assumption Used for Oil Sands Recovery in Western Canada
6. E&P Technology Characterization
7. Fuel Prices
8. End Use Demand Characterization
9. Discussion of Final Results
10. Supply Curves, Transportation Adders for EPA Base Case 2004, v. 2.1.9

1. Introduction

One of the primary tools that EPA's Clean Air Markets Division uses to evaluate air emissions policies is the Integrated Planning Model (IPM). IPM, a large linear program of the electric power sector, provides a detailed representation of power plant characteristics, operating regimes, plant dispatch, fuel use, and air emissions. IPM is used to evaluate the economic and emissions impact of alternative air emissions policies. IPM forecasts over a 20-25 year time horizon. A key input to IPM is the price of natural gas. IPM's gas price assumptions are developed using the North American Natural Gas Analysis System (NANGAS). Like IPM, NANGAS is a large-scale linear programming model that incorporates a detailed representation of gas supply characteristics, demand characteristics and an integrating pipeline transportation model to develop forecasts of gas supply, demand, prices and flows. Exhibit 1 shows the interaction of IPM and NANGAS.

Exhibit 1: IPM/NANGAS Interaction



The two models are operated in tandem and are iterated to develop a consistent Henry Hub gas price and total gas demand forecast. IPM uses natural gas data in electric market modeling as follows:

- IPM takes the natural gas supply curves and non-electric demand curves, which are developed within NANGAS and specified as a function of Henry Hub prices.
- The seasonal and annual natural gas transportation differentials are added to the supply and non-electric demand curve elements to generate the final delivered curves by IPM region.
- IPM finds the electricity demand for gas. To this is added the non-electric demand. The resulting combined demand is used with the supply curve to find the clearing price for gas.
- IPM linear programming formulation takes into consideration these curves as well as coal supply curves and detailed electric power plant modeling in determining

electric market equilibrium conditions. Oil usage is modeled as a function of price which is exogenously supplied to IPM.

In 2003, EPA sponsored an extensive peer review of NANGAS, conducted by an independent panel of prominent natural gas experts. NANGAS was updated based on all primary recommendations made by the peer reviewers and supply curves were generated for use in EPA Base Case 2004, v. 2.1.9.

This report is divided into the following sections. The report starts with a brief synopsis of NANGAS, the primary tool used for generating the supply curves. This is followed by detailed discussions of modeling methodologies and data used in NANGAS. The methodologies and data description are grouped in the following six sections:

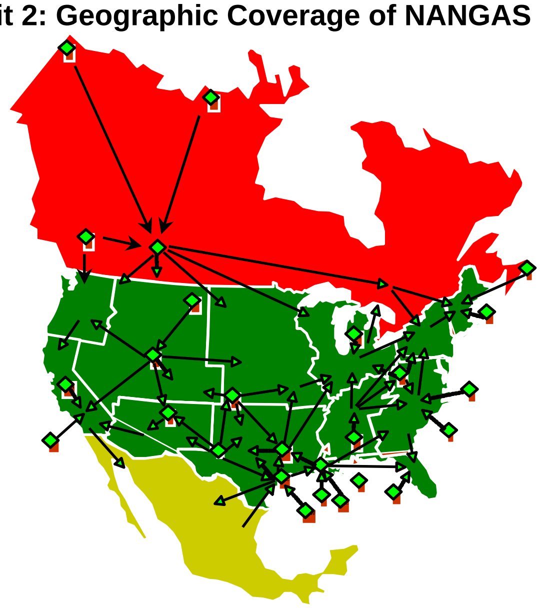
- i) Resources data and reservoir description
- ii) Treatment of frontier resources
- iii) Natural gas assumptions for oil sands recovery in Western Canada
- iv) Exploration and Production (E&P) technology characterization
- v) Fuel prices (oil, coal)
- vi) End use demand characterization

This is followed by discussion of natural gas results and supply curves used for EPA Base Case 2004, v. 2.1.9.

2. Brief Synopsis of NANGAS

ICF's integrated natural gas model, NANGAS, is designed to perform comprehensive assessments of the entire North American gas flow pattern. It is a large-scale dynamic linear program that models economic decision-making to minimize the overall cost of meeting natural gas demand.

Exhibit 2: Geographic Coverage of NANGAS



Important features of NANGAS are described below.

Natural Gas Market Prices in NANGAS are calculated based on the concept of "shadow prices". The model's material balance constraints calculates this shadow price indicating "How much better would the natural gas grid be with one additional unit of gas." These calculations take into account all regions and future years simultaneously in minimizing the cost of meeting demand. The calculations reflect the value of each potential activity that could be performed relative to adding one unit of gas or reducing one unit of demand to arrive at a "marginal activity".

Reservoir level analysis uniquely evaluates exploration, development and production at the level of over 20,000 individual reservoirs and undiscovered accumulations. NANGAS is distinguished by its detailed representation of reservoirs and reservoir characteristics and the use of type-curves to generate production profiles from the economics and technologies of production. (Type-curves are curves that are typically used in well testing to represent trends in pressure transient responses with different, layered geological structures.) NANGAS does not employ "decline rates" as an input in the forecasting of production. Rather "decline rates" are an output of the model and are a function of resource characteristics, production economics, and technology.

E&P technology performance is modeled by simulating the effect of E&P technologies on ultimate gas recovery and production profiles. Potential improved technologies and practices are characterized as explicit changes in reservoir or economic parameters. This approach is designed to allow for detailed assessments of future potential from individual reservoirs and to allow explicit changes to the technology be represented consistently across various practices for the entire North American resource.

Regional demand is modeled on a sectoral and seasonal basis, including the role gas storage can play in meeting gas demand. Demand is primarily represented by Census region. Some regions are further disaggregated in more detail either by state or regions within states. Demand is represented within each of its 26 regions as a load duration curve with four seasons.

End use demand is modeled for residential, commercial, industrial and electric utility sectors. Econometric equations define demand by sector. Industrial and electric sectors incorporate fuel competition, dispatch decisions, and new power plant builds. NANGAS iterates with IPM to better capture electric sector demand for natural gas.

Electric generation is modeled regionally with plant dispatch based upon operating cost. Competing power generation technologies are evaluated on a full-cost basis to determine lowest cost capacity additions.

Transportation is modeled by over 135 transportation links between supply and demand regions, balancing seasonal, sectoral, and regional demand and prices, including pipeline tariffs and capacity allocation. The pipeline network is largely represented as bundles of pipes, though in some regions individual pipes are represented. Gas moves over the network at variable cost. Pipeline expansion levels are modeled either as specified user input to the model or, alternatively, the user can let the model expand capacity endogenously whenever the market justifies expansion.

NANGAS is developed and maintained by ICF for use by both private as well as public sector clients. It is routinely updated and has been used to examine strategic issues relating to natural gas supply, pipeline infrastructure, pricing, adequacy, and demand characteristics.

3. Resources Data and Reservoir Description

As noted above, NANGAS underwent an extensive peer review process during 2003 in which the analytic framework, modeling methodologies, and data were thoroughly examined. In response to peer review comments, ICF revised and updated the resource module in NANGAS, to incorporate new data on resources, reserves, and reservoir parameters for the L-48 states and Canada. This section describes the approach used in NANGAS and documents the changes to the resource data and reservoir characterization that were implemented for EPA Base Case 2004, v. 2.1.9.

Undiscovered resource data used in NANGAS are consistent with the latest resource assessments conducted by governmental and private agencies within U.S. and Canada. A complete update to the undiscovered natural gas resource base for the Western Canada Sedimentary Basin (WCSB) and key regional updates within US was completed as new data became available in years 2002 and 2003. For the US, the primary data sources were the United States Geological Survey (USGS) and Minerals Management Service (MMS). For Canada ICF investigated the conventional resources assessment of the Canadian Gas Potential Committee (CGPC), and unconventional resources assessments published by the Alberta Energy Utilities Board (AEUB), publicly available reports and the provincial energy departments for Saskatchewan and British Columbia.

A particular area of update was the estimate of undiscovered resource base attributed to conceptual geologic plays in Canada. A conceptual play (or hypothetical play) is a geologic play that has not yet been 'proved by commercial oil and gas production. A conceptual play in Canada may have had some exploratory drilling and discoveries of non-commercial accumulations. Re-estimation and re-interpretation of existing data as well as availability of new data in year 2003 by CGPC and the National Energy Board (NEB) of Canada indicates significantly lower estimate for these plays than previously estimated.

Before describing the details of resources data used in NANGAS, it is important to explain the E&P forecasting methodology used in NANGAS. This discussion helps in understanding the resources data requirements for NANGAS and the rationale behind the resources data collection efforts.

Field Development and Production Forecast Methodology in NANGAS

Field development and production forecast methodology in NANGAS is as follows: Total resources are estimated for individual geologic plays. The undiscovered resources for each geologic play are distributed among size classes. Fields are discovered and developed subject to economic and reservoir and production engineering constraints. Reservoir engineering constraints are determined by the resource type and reservoir parameters such as porosity, permeability, pay thickness, water saturation, and reservoir area.

The NANGAS resource module estimates average reservoir parameters (such as porosity, permeability, water saturation, thickness, areal extent, reservoir pressure, etc.) for discovered (known) reservoirs and extrapolates these average reservoir parameters to undeveloped (unknown) reservoirs in the same or comparable geologic play. A production history match is obtained for developed reservoirs in producing fields utilizing production type curves for specific resource types (such as conventional, tight gas, coalbed methane, naturally fractured, etc.). These production type curves are also used to project future production from discovered reservoirs. The production type curves are also applied to undiscovered resources to generate typical production profiles based on estimated resource type, average reservoir properties and E&P technologies. Use of this approach helps in quantifying production potential based on reservoir depth, quality, and size as well as E&P technology.

The most important assumption influencing the production forecast is the resource size and the distribution of the undiscovered resource base into field or pool size classes and the economic field size class cutoff. Special efforts were taken to determine an accurate distribution of resources within appropriate size classes.

L-48 U.S. Resources and Reserves

This section describes the U.S. resource data sources and methodology used in NANGAS for EPA Base Case 2004, v. 2.1.9. The primary data source for the undiscovered resource base in NANGAS is the comprehensive national resource estimate completed by USGS in the year 1995. Resource data in NANGAS was updated to be consistent with the recently revised USGS resource assessments for nine oil and gas producing basins in the Rocky Mountain, Appalachia, and the states of Mississippi and Alabama. This update reduced the undiscovered resource base by 61 Tcf than previously estimated by USGS in 1995, and redistributed undiscovered resources between conventional, coalbed methane, and tight resource types in the Rockies and Appalachia consistent with latest USGS estimates. Exhibit 3 summarizes the U.S. Lower-48 undiscovered resource base used in NANGAS.

Exhibit 3: Undiscovered Resource by Play

Resource Type	Undiscovered Recoverable Resources, Tcf	Number of Plays
L-48 Onshore Conventional (non-associated)	137	230
L-48 "Tight"/ Continuous	208.2	28
L-48 Coalbed Methane/ Fractured Shale	119.9	47
Total L-48 Onshore	**465.1**	**305**
Offshore (Gulf of Mexico OCS)	192.9	17
Associated Dissolved Gas	85.0	NA
Total U.S. Lower –48	**743.0**	**322**

USGS and MMS Resource Assessments. NANGAS incorporates the 1995 USGS assessment of undiscovered resources for the onshore lower-48 states reported in the *1995 U.S. National Assessment of Oil and Gas Resources*. The geologic plays, supply producing areas and supply regions identified in the 1995 National Assessment provide the underlying structure for the resource database for the onshore U.S. The USGS is in the process of revising the National Assessment and as of the fourth quarter of 2003. New resource assessments were completed and available for nine onshore basins: Appalachian Basin, Powder River Basin, Denver Basin, Florida Peninsula, Montana Thrust Belt, Powder River Basin, San Juan Basin, Southwestern Wyoming, and Uinta-Piceance Basin. In addition, the new National Assessment incorporates the latest concepts in basin stratigraphy and petroleum-producing systems. As a result, the unit of the 'geologic play', which rolled-up to a 'geologic province' in the 1995 National Assessment has been replaced by 'assessment units' that comprise 'total petroleum systems' within geologic basins. An assessment unit in the new 2005 National Assessment corresponds approximately to a geologic play. Although the new USGS National Assessment will not be completed until late 2005, the new data for the completed basins were obtained and incorporated into the model for this effort. NANGAS will be updated periodically with the latest USGS resource assessments for individual basins as they become available.

For the Gulf of Mexico Outer Continental Shelf (OCS), NANGAS incorporates the estimated undiscovered recoverable resources from the U.S. Minerals Management Service *2000 Assessment of Oil and Gas Resources of the Outer Continental Shelf*. A methodology was developed that distributed these undiscovered resources into seventeen geographical plays defined by water depth and Gulf of Mexico Planning Area. The MMS is currently updating the OCS resource assessment, which is expected to be available in 2005 and will be incorporated in future versions of NANGAS. Currently, resources from emerging deep shelf gas plays in the Gulf of Mexico are not included in NANGAS as detailed data has not been published by MMS. An MMS press release from November 2003, however, estimates that undiscovered resources for deep shelf gas range from 5 trillion cubic feet (Tcf) to 20 Tcf.[1] The next version of the model will include resources in the deep shelf plays when additional data becomes available.

Crosswalk Geologic Plays and New USGS Assessment Units. The resource base in the model contains all of the results of the USGS 2005 National Assessment that were available to the public in late 2003. The changes to the undiscovered resource base are most apparent in the Appalachian and Rocky Mountain supply regions. The first step to incorporate the new USGS resource assessments was to crosswalk the geologic plays in NANGAS with the 'assessment units' identified in the 2003 resource assessments. There is often a one-to-one correspondence between the geologic plays defined in 1995 and the 2003 assessment units. In some cases, the 1995 geologic plays are omitted in the 2003 assessment, or are combined with other plays to correspond to a single assessment unit. In other cases, completely new assessment units are defined in 2003, which do not correspond to any 1995 geologic plays. The new USGS resource assessments were incorporated into NANGAS by creating a crosswalk between geologic plays and the 2003 assessment units. Once geologic plays and assessment units were matched, the estimated resources for the assessment units replace the resources

[1] United States Minerals Management Service Press Release, *Deep shelf gas may be more abundant in Gulf than earlier forecast*, Press Release Number 3012, November 19, 2003. United States Minerals Management Service, 2003, *Gulf of Mexico OCS Deep Shelf Gas Update: 2001 – 2002.*

associated with the corresponding geologic plays. Some geologic plays were deleted, others were combined, and new assessment units were added.

The new USGS National Assessment replaces the resource type of 'tight' or 'low-permeability' gas sands, with the concept of 'continuous' resources, which may be fractured gas shales, or low permeability sandstone and carbonate reservoirs. Continuous resources are extensive; contain no obvious structural component or downdip gas/ water contact; are often abnormally pressured; and are economically developed using large numbers of closely-spaced producing wells and well stimulation techniques such as hydraulic fracturing. The resource types for the new USGS assessment units are designated as 'conventional', 'continuous', or 'coalbed methane'. Each new assessment unit incorporated in NANGAS is assigned as either coal/ fractured shale, tight, or conventional. USGS assessment units designated as a 'continuous' were re-designated either as 'tight' or 'coal/fractured shale', in NANGAS depending upon the primary reservoir lithology of the assessment unit. The new USGS resource assessments show significant shifts in undiscovered resources between resource type categories in some producing basins, compared to the 1995 National Assessment. Conventional undiscovered resources are reduced in many plays and some hypothetical conventional plays are deleted. A few significant new conventional plays are added in the Montana Thrust Belt. Undiscovered coalbed methane resources are increased substantially in the Rocky Mountain region and Appalachian Basin compared to the 1995 National Assessment and continuous resources attributed to tight gas plays are reduced significantly compared to the 1995 National Assessment.

Field Size Distribution. For conventional resource plays or assessment units, the new USGS assessment continues to estimate a minimum, maximum, and median field size for undiscovered hydrocarbon accumulations in the play. The new USGS minimum, maximum, and median field size classes (FSC) were compared with the NANGAS field size distributions for corresponding geologic plays. The field size distributions for conventional resources in NANGAS compared favorably with the minimum, maximum, and median field size classes estimated by the USGS. In a few conventional plays the field size distribution appeared to be shifted towards larger field sizes in NANGAS compared to the new USGS assessment unit corresponding to the play. For these conventional plays, the internal field size distribution procedure was modified so that the maximum undiscovered field size in the NANGAS distribution does not exceed the maximum undiscovered field size class estimated by the USGS for the corresponding assessment unit.

The new USGS resource assessment does not apply the concept of a producing field to continuous and coalbed methane resource types. Instead, the remaining undiscovered resource is divided into conceptual cells representing the minimum, maximum, and median volume of reservoir that could be drained by a single well. The minimum, maximum, and median estimated ultimate recovery (EUR) is estimated for each cell, in addition to the drainage area (or well spacing) represented by a single cell. The cell EURs do not correspond directly to field size class or the field size distributions used in NANGAS for tight or coalbed methane plays. For unconventional plays, undiscovered resources were distributed in categories (or classes) by assuming a typical field containing 24 wells. This was found to be generally reasonable for most plays, compared to the corresponding USGS assessment units. Individual well spacing assumptions were reduced to reflect current production practices.

Reservoir Properties. The discovered reservoir database in NANGAS contains average reservoir parameters for known reservoirs in a geologic play. The average reservoir parameters from discovered producing reservoirs in a play are applied to undiscovered reservoirs in the play so that production can be projected using production type curves and a production history match. If porosity or permeability is unknown or unspecified for an undiscovered reservoir, the missing parameter is estimated using a porosity-permeability correlation. While a comprehensive re-evaluation of reservoir parameters in the NANGAS reservoir databases was not completed, some reservoir parameters were updated as new data were provided by the new USGS resources assessments. The updated reservoir parameters included average reservoir depth, more complete data on gas composition and impurities, and percent of federal land in the play.

While there are inherent limitations and uncertainties in estimating average reservoir parameters for known producing reservoirs and applying these parameters to undiscovered resource base, ICF has found that it is a better approach than applying econometrically determined finding rates or reserves-to-production (R/P) ratios. This approach is also useful to correctly model the impacts of technology improvement and certain policy initiatives influenced by technology. ICF recognizes that in modeling the long-term development of resources, smaller fields are found in the future as larger fields are discovered and developed first. Reservoir properties of smaller fields may not be same as the larger fields, so the average reservoir parameters applied to small fields such as permeability, porosity, and water saturation should be adjusted over time, which would impact the field production profiles. This issue may be particularly important in some mature conventional producing regions such as the Permian Basin and Gulf Coast, which are experiencing rapid depletion of smaller fields in some plays. ICF tested this idea with some limited sensitivity analyses in which the reservoir quality of smaller undiscovered fields was reduced in selected regions. While changing the reservoir parameters for undiscovered reservoirs did impact (and reduce) projected production, the impacts of other model adjustments, such as resource base and their size distribution, were more significant.

U.S. Reserves and Reserve Growth. The 1995 USGS National Assessment estimates that approximately 294 Tcf of the U.S. resource base will come from reserves growth of existing fields. Approximately 200 Tcf of reserve growth will be from onshore non-associated gas production in the Lower-48 states. The U.S. MMS estimates that 67 Tcf of future resources will be contributed by reserve growth in existing offshore fields in the OCS. The reserve growth resources in NANGAS are consistent with the USGS and MMS estimates. Reserves are booked as a function of development drilling.

Canada Resources and Reserves

This section describes the Canadian resource data sources and methodology used in NANGAS for EPA Base Case 2004, v. 2.1.9. The NANGAS methodology for projecting production from discovered and undiscovered resources of the WCSB is similar to the methodology for projecting production from the U.S. resource base. Total resources are estimated for individual geologic plays. The undiscovered resources for each geologic play are distributed among field size classes. Fields are discovered and developed subject to economic and reservoir and production engineering constraints. The reservoir engineering constraints are determined by the resource type and reservoir parameters such as porosity, permeability, pay thickness, water saturation, and reservoir area.

Other gas-producing regions in Canada, such as the Mackenzie Delta and offshore Atlantic including Sable Island, are handled in the model as exogenous gas supply projects. The production forecasts for these regions are based on current and expected project capacity and planned project expansions. They are explained in detail in a separate section of this report.

Exhibit 4 summarizes the WCSB resource base used in NANGAS.

Exhibit 4: Undiscovered Resources in WCSB

	Undiscovered Resources, Tcf (Original Gas in Place)	**Number of Plays**
Conventional Established Plays	133.4	79
Conventional Conceptual Plays	40	8
'Tight' Gas/ Continuous	206	15
Coalbed Methane	192.3	24
Total	**572**	**126**

In this effort, a substantial redistribution of undiscovered resources among the various resource type categories have been conducted consistent with published recent estimates by the CGPC. Estimated undiscovered resources in conventional conceptual plays[2] have decreased by more than 50% than previously estimated. In part, this is because the recent CGPC resource assessments represent a more conservative view of hydrocarbon resources in conceptual plays. Also, some conceptual plays in earlier WCSB resource assessments now have proved commercial gas production and have moved to the category of established plays. Estimated unconventional (tight gas and coalbed methane) resources have increased by 50% than previously estimated based on better data and analyses completed by various Canadian agencies and private firms.

Conventional Resources in Established Plays. A complete update of the undiscovered resource base was completed in NANGAS for EPA Base Case 2004, v. 2.1.9. ICF acquired the most recent resource assessment for the WCSB published by the CGPC[3] and updated undiscovered resources data for established plays in WCSB.

The reservoir database in the model is updated with reservoir parameters provided for each play in the CGPC report. Following is a list of updated reservoir parameters that are captured in the reservoir database:

- Average Recovery Factor
- Porosity
- Water Saturation
- Temperature Gradient
- Gas Gravity
- Average Z Factor
- Depth
- Pay Thickness
- Formation Volume Factor
- Reservoir Pressure Gradient
- Heat Value
- Gas Composition

[2] Conceptual plays have not been proven to contain commercial hydrocarbon accumulations. Most conceptual plays have been explored to some extent, but no producing fields have been established.
[3] Canadian Gas Potential Committee, 2001, *Natural Gas Potential in Canada – 2001*, Calgary, Alberta.

Total conventional undiscovered resources in established plays is 133.4 Tcf and are distributed to field size class categories using the modified Arps-Roberts methodology.

Conventional Resources in Conceptual Plays. Conceptual plays are geologic plays that have no significant discoveries to date, but do have favorable geologic features for oil or gas production. Many conceptual plays have been tested with exploratory drilling and may have non-commercial discoveries. The 2001 CGPC identifies six conceptual plays in the WCSB, but provides no quantitative assessments of the resource potential. NANGAS currently assumes 40 Tcf of resource in eight conceptual plays for the WCSB, including six conceptual plays identified in the 2001 CGPC study and two conceptual plays identified in the earlier Geological Survey of Canada (GSC, 1993) resource assessment. The 40 Tcf of resource assumed for conceptual plays represents the difference between the 2001 CGPC assessment of total undiscovered resources in the Western Canada Sedimentary Basin (133.4 Tcf) and an alternate view of undiscovered WCSB resources (174 Tcf) presented by the Canadian Energy Resource Institute (CERI).[4] The 40 Tcf of resources in conceptual plays is distributed equally among the eight conceptual plays. Reservoir parameters for the eight conceptual plays are estimated from known analogous geologic plays.

Tight Gas/Continuous Resources. The definition of 'tight' gas reservoirs in Canada has not been established by a governmental entity, as is the case in the United States. 'Tight' or 'continuous' resources are not limited to reservoirs with average permeability less than 0.1 millidarcy, but are generally defined as regionally extensive reservoirs that are sub-economic using normal completion and production standards. Most tight reservoirs in the WCSB have been identified in the deep basin areas as regionally pervasive, thick, gas-saturated reservoir sequences that have abnormal reservoir pressures and no apparent downdip gas/water contact. Three known tight gas regions in the WCSB include:

- Deep Basin; stacked Mesozoic clastic reservoirs
- Foothills, Disturbed Belt; naturally fractured low-permeability reservoirs
- Northern Plains; areally-extensive, shallow reservoirs with subtle natural fractures and no apparent local structure; require hydraulic fracturing and horizontal drilling

Few play-level assessments of the resource potential of tight gas reservoirs in the WCSB are publicly available, although this situation changing. The tight gas/continuous resource update completed as part of EPA Base Case 2004, v. 2.1.9 includes gas-in-place for fifteen identified tight geologic plays.[5] The gas-in-place estimated for the individual plays ranges between one and three billion cubic feet (Bcf) per square

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[4] CERI maintains that the Canadian Gas Potential Committee (CGPC) was too conservative and excluded a number of areas in the WCSB "thought to have reasonable prospects for natural gas." CERI commissioned a study to re-evaluate the WCSB undiscovered resource base, incorporating both the 2001 CGPC study and the earlier Geological Survey of Canada (GSC) work, with an emphasis on the assessment of gas-in-place for conceptual plays. The reference for the 40 Tcf undiscovered resources attributed to conceptual plays is *Canada's Ultimate Natural Gas Potential-Defining a Credible Upper Bound*, Drummond Consulting, March 2002 as reported in *Potential Supply and Costs of Natural Gas in Canada*, Canadian Energy Research Institute, 2003.

[5] *Exploration Assessment of Tight Gas Plays, Northeast British Columbia*, 2003, Petrel Robertson Consulting, Calgary, AB and Hayes, 2003, The Deep Basin- A Hot "Tight Gas" Play for 25 Years, Petrel Robertson Consulting, presented at American Association of Petroleum Geologists Annual Convention, May 11-14, 2003, Salt Lake City, Utah.

kilometer. A low estimate and a high estimate of gas-in-place were provided for each play. NANGAS currently contains the low estimate of 206 Tcf for the tight gas resource base; the total high estimate for total tight gas resources is 546 Tcf. The low estimate is more reasonable because the WCSB has very little production from tight reservoirs. As tight gas development proceeds in the future the estimated resource base and its characterization will be revised, and a larger tight gas resource base may be justified.

Coalbed Methane. The current update greatly improves the representation of the WCSB coalbed methane resource base in NANGAS, drawing upon recent geologic analysis of coalbed methane plays and recent resource assessments by the CGPC and provincial energy agencies in Alberta and British Columbia.[6] Twenty-four coalbed methane plays are specified in the model, ten in Alberta and twelve in British Columbia. Little data are available for reservoir parameters besides reservoir depth and gas content. Typical default parameters (langmuir pressure, langmuir volume, sorption time, pressure, permeability, thickness, porosity etc.) are used based on coalbed methane resources located in the U.S. These will be updated as reservoir specific and basin specific data become available in the future. A low estimate and a high estimate of gas-in-place were provided for each play. EPA Base Case 2004, v. 2.1.9 currently contains the low estimate of 192 Tcf for the coalbed methane resource base; the high estimate for coalbed methane resources is 294 Tcf. As more coalbed methane activities are conducted in Western Canada, the data and size of the resource base will be revised.

Interim Calibration of NANGAS Production Results

As the resource data, its characterization and implementation were updated as part of EPA Base Case 2004, v. 2.1.9 effort, it was necessary to compare and calibrate regional production trends achieved in NANGAS with established history. As the effort for creating EPA Base Case 2004, v. 2.1.9 supply curves progressed, regional NANGAS results were compared with recent history and reservoir parameters were updated to ensure consistency with near term production trends. This calibration exercise ensured that the near-term regional production forecasts did reflect recent production trends. For example, if regional production is in decline, the model forecast for the supply region must capture that trend in the initial model years. The Rocky Mountain and Gulf Coast regions proved to be especially challenging to calibrate the production output and 'fine tune' the model revisions. Regional natural gas production reports provided by Lippman Consulting, Inc.[7] were helpful for calibrating the model update in these supply regions. At EPA's suggestion, ICF purchased two Lippman Consulting quarterly production reports, which contained regional and state monthly gas production data as well as drilling data and rig utilization. Exhibits 5, 6, and 7 illustrate the production trend

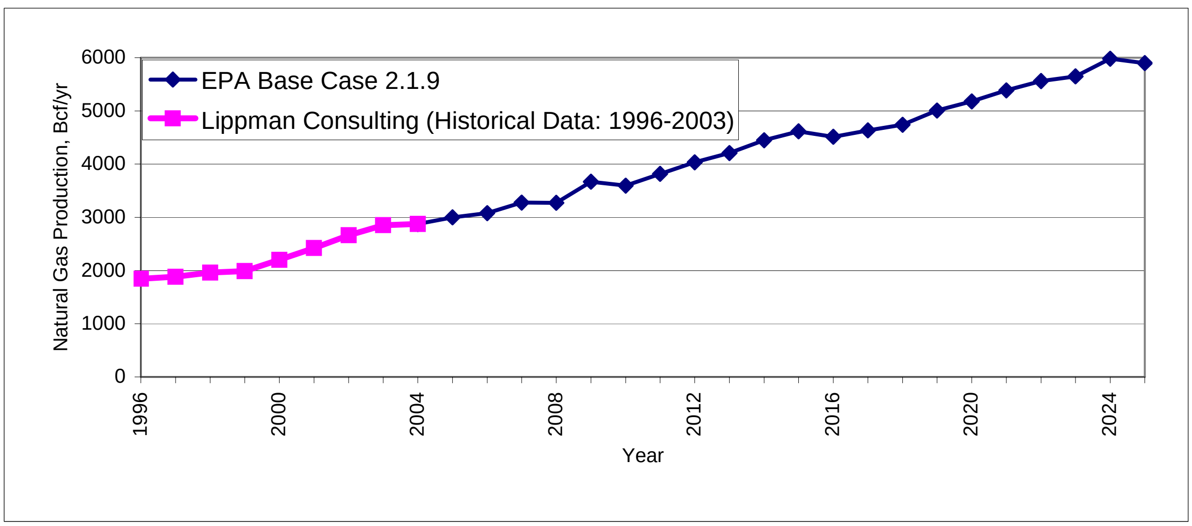
[6] Sources: 1. Alberta Geological Survey and Alberta Scientific Research Authority, 2002, *Coalbed Methane Potential of Upper Cretaceous-Tertiary Strata, Alberta Plains*, Earth Sciences Report 2002-06. 2. Alberta Geological Survey and Alberta Scientific Research Authority, 2002, *Regional Evaluation of the Coalbed Methane Potential of the Foothills and Mountains of Alberta*, Earth Sciences Report 2002-05. 3. British Columbia Ministry of Energy and Mines, *Fact Sheet: B.C. Coalbed Methane Resources* 4. British Columbia Ministry of Energy and Mines, 2003, Map*: Coalfields and Coalbed Methane Potential in British Columbia.* 5. Low case gas-in-place estimate for coalbed methane in Mannville Formation and Paskapoo Formation coals from the 2001 Canadian Gas Potential Committee assessment of the WCSB.

[7] Lippman Consulting, Inc., 2003, *Gulf Region – 2003 2nd Quarter Natural Gas Production Report*.
Lippman Consulting, Inc., 2003, *Rocky Mountain Region – 2003 2nd Quarter Natural Gas Production Report*.

comparison between NANGAS and Lippman Consulting reports. These exhibits illustrate that the calibration exercises were able to improve consistency between longer term projected production trends and the shorter term trends recently observed in key producing basins in the U.S.

An example comparison of production forecasts for the WCSB is shown in Exhibit 8. The EPA Base Case 2004, v. 2.1.9 forecast for WCSB using NANGAS is compared to the 2003 National Petroleum Council[8] forecast, and the recent production forecasts from the National Energy Board (NEB).[9] The production outlook for WCSB remains flat to declining and rises modestly after 2015 as unconventional resources become an increasing component of WCSB production. A decrease in year 2015 is due to Alaska entering the marketplace and depressing prices in Alberta for a few years. There is a short run-up of production just before Alaska enters the marketplace as producers maximize production from existing fields. The NANGAS, NPC 2003, and NEB Technovert WCSB production outlooks presented in Exhibit 8 are very similar, albeit at a lower price in NANGAS than in NPC 2003.

Exhibit 5: Production Comparison and Forecast for U.S. Rockies



[8] National Petroleum Council, 2003, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, Volume II, Integrated Report. U.S. National Petroleum Council, Washington D.C.

[9] National Energy Board, 2003, *Canada's Energy Future, Scenarios for Supply and Demand to 2025*, Calgary, Alberta.

Exhibit 6: Production Comparison and Forecast for Texas Rail Road Commission (RCC) Districts 1-4

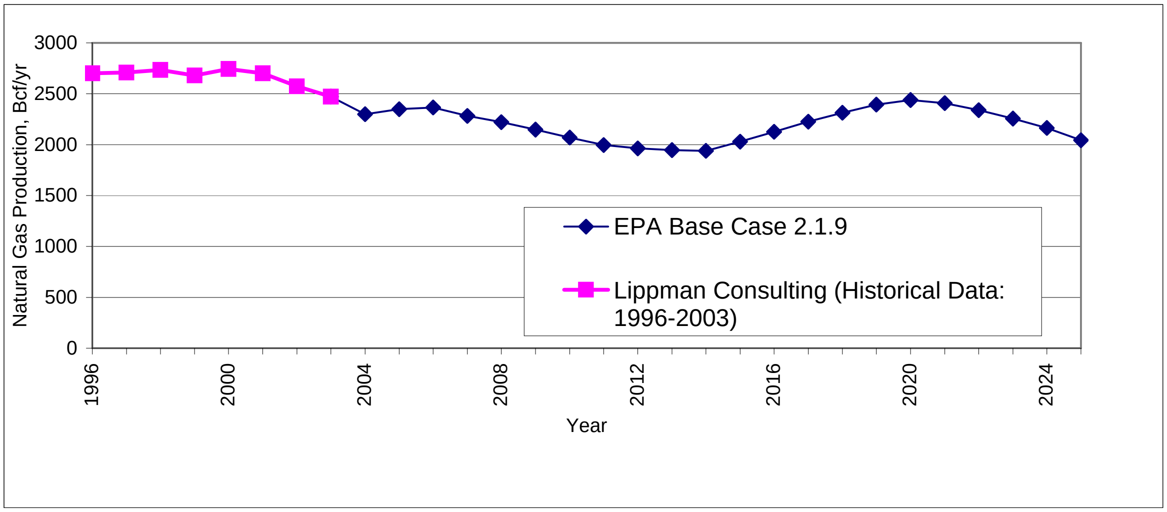


Exhibit 7: Production Comparison and Forecast for Louisiana, Alabama, Florida and Mississippi

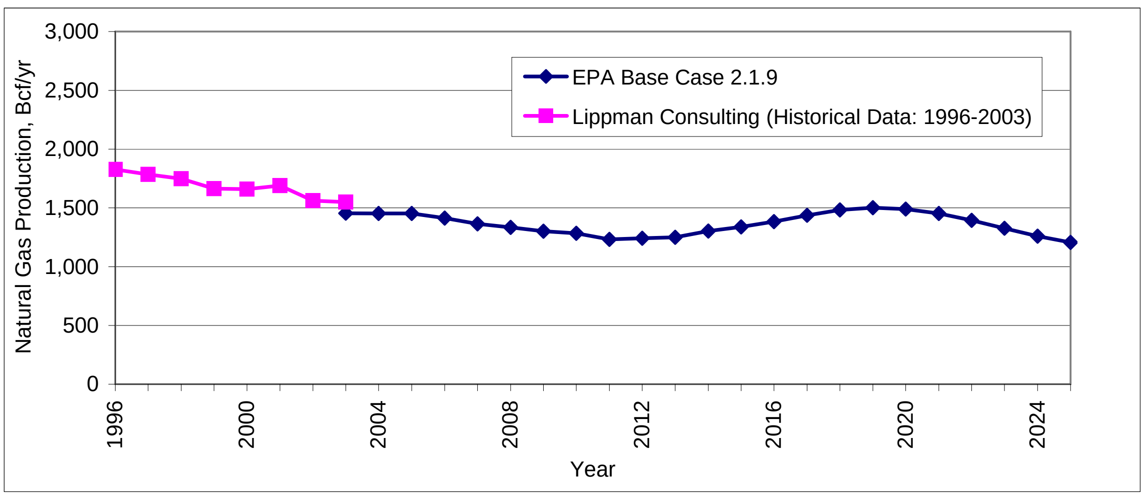
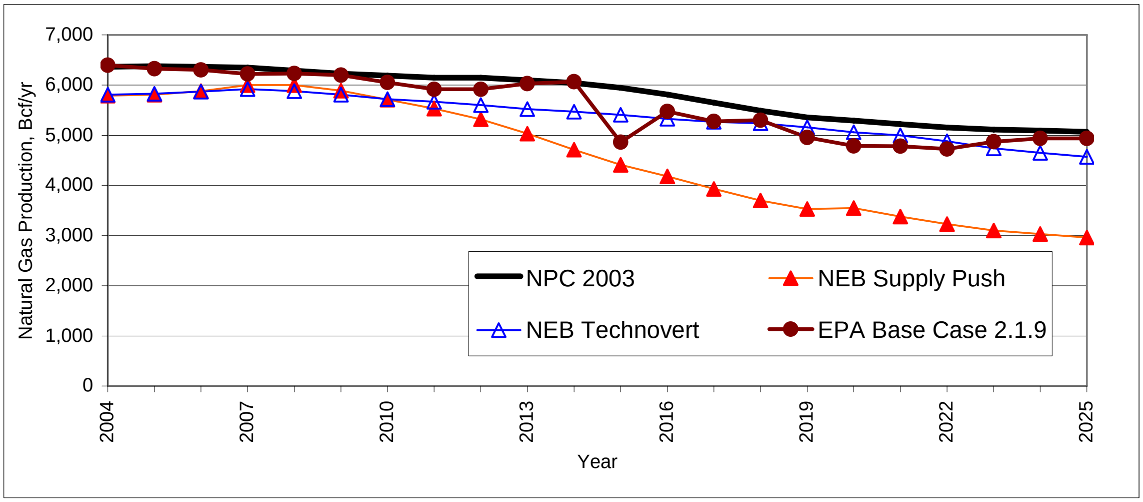


Exhibit 8: Comparison of WCSB Production Forecasts



4. Treatment of Frontier Resources

In addition to the traditional sources of natural gas resources as described in the Resources Data and Reservoir Description section, NANGAS also contains resources located in frontier regions. These frontier resources (or project level supplies) are used to model large projects, which can have dramatic impact on prices in the near term. Frontier resources for this modeling effort include Alaska North Slope, Mackenzie Delta, Sable Island and LNG. We do not start from the resource base in these categories and do not develop production cost curves; rather we use threshold pricing (trigger prices) for these supplies to come online. The two attributes of these supply sources, maximum capacity by year and minimum threshold price, are exogenously provided.

These frontier resources are modeled in NANGAS as market pull, indicating they are available at threshold prices. These projects are brought on-stream only when the threshold prices are reached and the discounted net present value of the net revenue stream (i.e. the marginal price at the demand node less the marginal price at the supply node plus full cost of transportation) is positive. Once the decision is made, the supply project is used every year until the end of the model run.

Information used to characterize these frontier resources was obtained from various publicly available sources. Supply curves were generated for each frontier resource category.

- **Alaska North Slope (ANS):** The natural gas resource located in ANS is substantial, with proven reserves of 35 Tcf in the Prudhoe Bay area where most of the oil production activities are currently conducted. In addition to the proven reserves, USGS estimates that ANS contains as much as 100 Tcf of undiscovered resource. To date, this resource is stranded because it lacks effective commercial access to markets. In fact, 6-8 Bcf/d of gas that is currently produced as part of the oil activities in the Slope is re-injected back into the Slope's oil reservoirs as part of the pressure maintenance programs. As the oil fields mature and produce less oil and more gas, the need for and the economic viability of gas re-injection diminishes. ANS producers, various pipeline project proponents, and governments in both the US and Canada have stepped up efforts to bring to fruition the long-held goal of monetizing ANS gas. For EPA Base Case 2004, v. 2.1.9, ICF has chosen to show Alaska North Slope gas being brought to the Lower-48 markets starting in the year 2015 at a threshold wellhead price of $0.75/MMBtu. Alaska supplies start at 4.1 Bcf/d in year 2015, expands to 4.6 Bcf/d in 2017, and then again in 2019 to a total of 5.2 Bcf/d. We have not assumed any gas supplies from the Arctic National Wildlife Refuge (ANWR) in this study. Exhibit 9 shows the assumption for Alaska North Slope.

- **Mackenzie Delta (MD):** In the Mackenzie delta area of Canada (300 miles east of Prudhoe Bay), exploration drilling from 1970 and 1989 discovered 53 oil and gas pools about equally divided between the onshore and offshore areas. The Mackenzie delta area contains approximately 9-12 Tcf of discovered gas and over 60 Tcf of undiscovered gas, some of which is in pools sufficiently large to justify construction of a new gas pipeline to take the gas south to Alberta. Supply potential from Mackenzie delta can be over 2 Bcf/d. All of the Mackenzie delta discoveries are stranded at the present time, although several development proposals are under consideration. There is a renewed interest by Governments, producers, pipeline companies and Aboriginal peoples in exploiting the natural gas resources and transporting them to the Lower 48 markets due to projections of strong growth in natural gas fired generation, and the recent strength of gas prices. For EPA Base Case 2004, v. 2.1.9, ICF assumed that Mackenzie Delta gas can be brought to the Lower-48 markets starting in the year 2009 at at a threshold wellhead price of $1.0 /MMBtu. Mackenzie Delta supplies start at 1.2 Bcf/d in year 2009, expand to 1.5 Bcf/d three years later in 2012, and then again in 2021 to a total of 2.0 Bcf/d. On average, around 75% of Mackenzie Delta volume is used in oil sands recovery projects in Western Canada. Volume of gas used for oil sands recovery in Western Canada is not a function of oil price.

Both Alaska as well as Mackenzie Delta supplies are delivered in Alberta and then re-delivered to L-48 via existing pipelines and expansions. Exhibit 9 shows the assumption for Mackenzie Delta.

Exhibit 9: Assumptions for Alaska North Slope and Mackenzie Delta

Frontier Resurce Supply Description	First Year of Potential Expansion	Trigger Price, 2003$/MMBtu	Capacity, Bcf/d	Cumulative Capacity, Bcf/d
Alaska North Slope	2015	0.75	4.10	4.1
Alaska North Slope (incremental)	2017	0.75	0.51	4.6
Alaska North Slope (incremental)	2019	0.75	0.58	5.2
Alaska North Slope (incremental)	2021	0.75	0.52	5.7
Mackenzie Delta	2009	1.00	1.20	1.2
Mackenzie Delta (incremental)	2012	1.00	0.30	1.5
Mackenzie Delta (incremental)	2015	1.00	0.50	2.0

- **Sable Island:** Estimated recoverable resources in Offshore Nova Scotia is over 30 Tcf. Sizeable quantities of natural gas are believed to be deposited in the Sable Island Sub Basin, deepwater Laurentian and Sydney channels, Georges Bank and St. Pierre Island. The Georges Bank and St. Pierre Island are currently under moratorium and no drilling has taken place. Sable Island shows the most promise for production, and will be supplemented by deepwater supplies from the region in the longer term. This study included supply only from Sable Island because of development activities in the area. Other regions of the area are in early stages of leasing and data collection, and publicly available gas resource data are incomplete. According to the CGPC, Sable Island is estimated to contain 3.7 Tcf of proven reserves, and 8.1 Tcf of undiscovered marketable natural gas. Commercial production from Sable Island started in December 1999. Sable Island gas is shipped over Maritimes and Northeast pipeline to the Canadian Maritimes and U.S. Northeast.

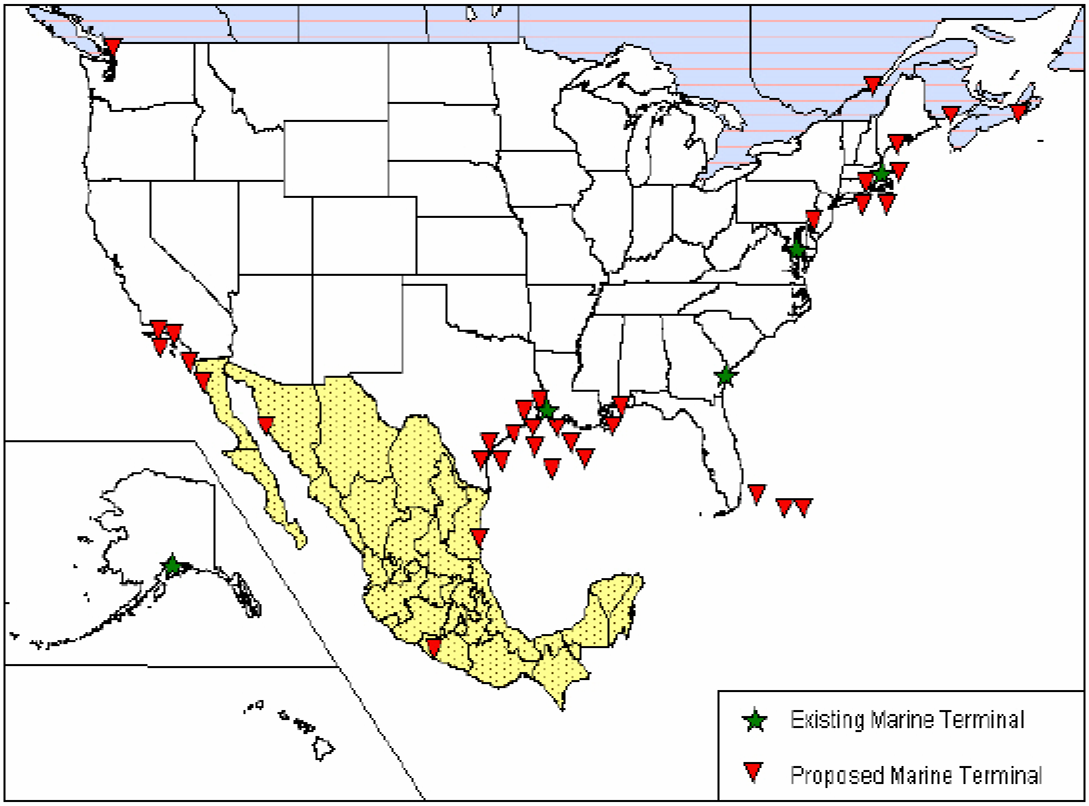
  Sable Island is assumed to grow modestly in the near term reflecting the current difficulties in the productivity of wells located in the offshore fields. A first expansion of 250 MMcfd is assumed in the year 2008 and the next expansion in the year 2015 making the total volume to 1.0 Bcf/d by the year 2015 (Exhibit 10). A threshold price of $1.35/MMBtu at the tailgate of Sable Island reflects the minimum threshold cost of production from Sable Island. Assumptions for Sable Island supplies have a direct impact on an eastern Canada LNG terminal economics.

Exhibit 10: Assumptions for Sable Island

Frontier Resurce Supply Description	First Year of Potential Expansion	Trigger Price, 2003$/MMBtu	Capacity, Bcf/d	Cumulative Capacity, Bcf/d
Sable Island	Existing	NA	0.50	0.5
Sable Island (incremental)	2008	1.35	0.25	0.8
Sable Island (incremental)	2015	1.35	0.25	1.0

- **Existing and Potential Liquefied Natural Gas (LNG) Terminals:** LNG is natural gas that has been transformed to a liquid by super-cooling it to minus 260 degrees Fahrenheit, reducing its volume by a factor of 600. LNG is then shipped on board special carriers, and the process is reversed at a receiving facility with the re-gasified product delivered via pipeline. Historically, LNG has supplied less than 1% of overall U.S. gas demand, due to high costs of transportation and liquefaction. Recently, however, improvements in the liquefaction process, combined with decreasing shipping costs, have resulted in a 50% decline in supply costs. The decrease in LNG cost has also come at a time when U.S. natural gas prices have increased over three folds compared to average price of $2.50-$3.0/MMBtu of the 1990s. In addition to the increased competitiveness of LNG, stranded gas reserves amounting to over 4,000 Tcf worldwide are making LNG an attractive gas supply option to meet rapidly increasing demand. This has led to many U.S. majors such as ExxonMobil, ConocoPhillips, Shell, BP etc. to look into tapping stranded natural gas resources in countries like Qatar, Trinidad, Algeria, Indonesia, Australia and others. Over 30 LNG import terminal proposals have been announced within U.S. in the hope of tapping these cheaper natural resources (see Exhibit 11). LNG is projected to make up a growing percentage of imports in coming decade.

Exhibit 11: Existing and Proposed Marine LNG Terminals as of June 2004



There are currently four LNG import terminals in the U.S. that are under operation, and modeled in NANGAS. All four existing LNG terminals are assumed to operate at 85% of their full rated capacity every year. Planned expansion levels on existing terminals are taken from publicly available data. Within NANGAS planned expansions are assumed to occur at no threshold price.

Gulf Coast LNG is assumed to expand at pre-defined threshold prices. These expansions do not reflect any specific terminal but rather a general increase in LNG volumes in the region. The Gulf Coast LNG threshold price is set at $3.00-$3.50/MMBtu. Maximum available LNG volume in the region is 3.3 Bcf/d. NANGAS solves for the actual volume realized based on supply/demand balancing. Bahamas LNG is assumed to come online in the year 2008 at 0.50 Bcf/d. Assumptions for existing and potential LNG capacity are listed in Exhibit 12.

Exhibit 12: Assumptions for Existing and Planned LNG Capacity

Frontier Resurce Supply Description	First Year of Potential Expansion	Trigger Price, 2003$/MMBtu	Capacity, Bcf/d	Cumulative Capacity, Bcf/d
Distrigas	Existing	NA	0.30	0.3
Distrigas @85% Capacity Utilization	2004	0.00	0.07	0.4
Distrigas Planned Expansion	2005	0.00	0.16	0.5
Cove Point	Existing	NA	0.08	0.1
Cove Point @25% Capacity Utilization	2004	0.00	0.12	0.2
Cove Point @50% Capacity Utilization	2005	0.00	0.18	0.4
Cove Point @85% Capacity Utilization	2006	0.00	0.26	0.6
Elba Island	Existing	NA	0.22	0.2
Elba Island @85% Capacity Utilization	2005	0.00	0.15	0.4
Elba Island Planned Expansion	2006	0.00	0.21	0.6
Lake Charles/Gulf Coast LNG	Existing	NA	0.53	0.5
Gulf Coast LNG (New Terminal)	2006	3.00	0.25	0.8
Gulf Coast LNG (New Terminal)	2009	3.25	0.50	1.3
Gulf Coast LNG (New Terminal)	2010	3.25	0.50	1.8
Gulf Coast LNG (New Terminal)	2011	3.25	0.50	2.3
Gulf Coast LNG (New Terminal)	2012	3.50	0.50	2.8
Gulf Coast LNG (New Terminal)	2016	3.50	0.50	3.3
Bahamas LNG	2008	2.50	0.80	0.8

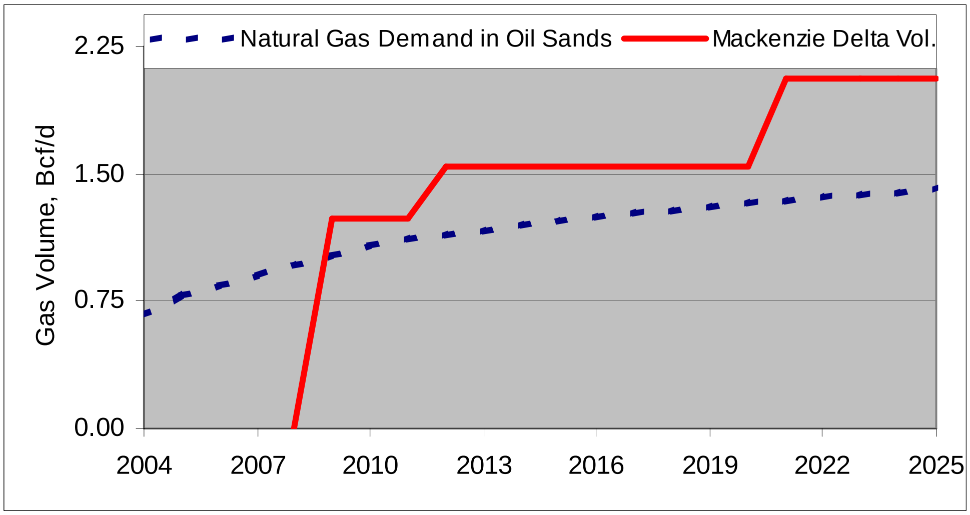
5. Assumption of Natural Gas Used for Oil Sands Recovery in Western Canada

Bitumen resources contained in Western Canada's oil sands deposits offer attractive opportunities, as the resource is well defined and delineated. The extraction and upgrading of oil from oil sands needs a large amount of natural gas. Mining and upgrading projects use natural gas as a source of process heat and feedstock and use about 0.4 Mcf of natural gas per barrel of oil produced. In situ projects use natural gas as a source of generating heat to produce steam for thermal operations, using about 1.0 Mcf of natural gas per barrel of oil.

The total natural gas requirement for oil sands recovery is assumed to double by 2025 to a level of 1.4 Bcf/d by year 2025. This is consistent with the Supply-Push case of the NEB study (Canada's Energy Future: Scenarios for Supply and Demand to 2025, published in 2003). The "Supply-Push" NEB case was used because the Henry Hub price in this case is on average similar to the Henry Hub price resulting under EPA Base Case 2004, v. 2.1.9.

Exhibit 13 shows natural gas demand assumed for oil sands recovery and Mackenzie Delta volume in Bcf/d. On average, around 75% of Mackenzie Delta volume is used in oil sands recovery projects in Western Canada, remaining 25% is exported to L-48 U.S. As noted earlier in the discussion of Mackenzie Delta gas, the volume of gas used for oil sands recovery in Western Canada is not a function of oil price.

Exhibit 13: Natural Gas Use for Oil Sands Recovery in Western Canada



Natural gas supplies and prices are major factors affecting oil sands recovery in Western Canada. If natural gas prices become very high or natural gas supplies become short in supply in Western Canada, then oil sands recovery could lag. Alternatives to natural gas include: gasification of bitumen, use of coal through clean coal technology, nuclear energy etc., but these are not currently in use for oil sands recovery.

6. E&P Technology Characterization

NANGAS uses E&P technology levers that are applied to the resource base in order to forecast productive capacity and production. In order to assure consistent analytical results from NANGAS and to appropriately address E&P technology issues, data for use in updating key NANGAS technology assumptions were obtained through a combination of research and analysis of governmental and industry sources. Key data elements were derived from the published literature, Energy Information Administration (EIA) publications, and proprietary sources. The following three general assumptions are made in developing E&P technology parameters in NANGAS.

- E&P technologies will continue to advance at a rate consistent with historical trends.
- Despite recent declines, we assume that investments in R&D will stabilize (by private/public partnerships, multi-company research consortia, etc.) with corresponding technological advances continuing.
- Insights and interpretation of the E&P R&D efforts conducted at the Strategic Center for Natural Gas (SCNG), U.S. Department of Energy (DOE) were used in determining technological levers and advancements rates.

The E&P technology assumptions and improvements in NANGAS were developed to capture gradual technology advances that would impact the North American gas market. A drastic/sudden improvement in E&P technologies is not assumed. Both current state-of-the-art as well as possible advanced technology parameters were used to model the potential impact of expanded technology application on the gas market. The E&P technology parameters used in NANGAS are as follows:

- **Skin Factor**: Represents drilling technology (drill bit design, air drilling, mud drilling etc.), completion/stimulation technology (acidizing, fracturing, perforation angle and size etc.). Sources of data include trade publications, SPE literature, and DOE.

- **Fracture Length/Conductivity:** Represents hydraulic fracturing technology (such as proppant design, type etc.). Sources of data include SPE literature, DOE and standard operating procedures.

- **Horizontal Well Length:** Represents drilling technology. Sources of data include SPE literature, Oil and Gas Journal.

- **Success Rates:** Represents seismic technology (3-D, 4-D seismic surveys). Sources of data include EIA, SPE literature and company press releases.

- **Drilling Capacity:** Represents drilling footage drilled. Sources of data include API and professional judgment.

Exhibit 14 shows how the specific E&P technology factors considered were varied in the analysis. These technology parameters were updated based on peer review recommendations.

As shown in Exhibit 14, "skin factor," a dimensionless factor representing the restriction on gas flow in the near-wellbore domain, improves from a current value of 6 to a value of 2 with the application of advanced technology. Completion and stimulation techniques were also assumed to improve for unconventional resources. Current practices achieve on average 200 feet of effective fracture half-length (400 feet tip-to-tip). With improvements in fracturing technology, it increases to 500 feet. In line with the fracture half-length, the fracture conductivity, a measure of flow capacity of an induced fracture, was assumed to increase from 1000 md-ft to 3000 md-ft. Onshore success rates improve at 0.5% per year and offshore at 0.8% per year consistent with AEO 2004 assumptions. As the technology improves over time, the horizontal wells are expected to increase in utilization and length of laterals. Horizontal wells were assumed to cost on average 30% more than the vertical wells. Also, the dry hole rates for development as well as exploration wells were assumed to decline with technology improvement. In this study, the technology improvements did not affect the rig retirement rate as the rig drilling capacity for current and advanced technologies was considered to be the same. Compressor installation costs are assumed to be $1200/BHP.

Cost and economic parameters were also updated in the analysis. Operating costs were assumed to reduce by 0.54% per year consistent with AEO 2004 assumptions. Consistent with AEO 2004 assumptions, drilling costs for onshore regions decreased by 1.87% per year and for offshore regions by 1.2% per year.

In NANGAS, these advances in technology do not occur immediately. Time to develop, test, market, and gain operator acceptance of the practices are considered in developing the technology penetration curves. Applications are phased into the marketplace with costs initially being higher and gradually declining as the market expands. The evolution of E&P technology was analyzed by limiting both the market penetration rate and the ultimate saturation of key advances. This resulted in typical "S" shaped technology penetration curves.

Exhibit 14: E&P Technology Assumptions for EPA Base Case 2004, v. 2.1.9

E&P Technology Parameter	Current Technology	Advanced Technology	% Improvement per year
Skin Factor (all resource types), dimensionless	6	3	2.2
Fracture Half Lengths, ft	200	500	6.5
Fractrure Conductivity, md-ft	1000	3000	8.7
Horizontal Wells, ft	750	2500	10.1
Horizontal Well Applicability for Accumulations in Field Size Class (USGS definition of Field Size Class 10 contains average recoverable resources of 144 Bcf)	10	10	0.0
Initial Drilling Cost ($/ft)	JAS 2000	90% of JAS 2000	0.4
Annual Drilling Cost Decline (Offshore), %	1.20	1.20	1.2
Annual Drilling Cost Decline (Onshore), %	1.87	1.87	1.9
E&P Operating Cost Decline, %	0.54	0.54	0.5
Compression Installation Cost ($/BHP)	1200	1200	0.0
Compression O&M Cost ($/Mcf)	0.15	0.0995	1.2
Horizontal Well Cost With Respect to Vertical Well Cost, fraction	1.3	1.17	0.4
Exploration Success Rates, %			
- Conventional	35	39	0.5
- Tight	35	39	0.5
- Natural Fracture	35	39	0.5
- Water Drive	35	39	0.5
- Coal and Shale	50	55.5	0.5
- Gulf Offshore	35	41.2	0.8
Development Success Rate	80	90	0.5

The overriding principle of NANGAS decision-making is that all E&P decisions are based on purely economic factors as an operator would do in field conditions. All project investment decisions in NANGAS are based on meeting a specified hurdle rate. Based on peer reviewer recommendations, this minimum hurdle rate is set at 15% for exploration projects and 12% for development drilling projects.

7. Fuel Prices

Natural gas prices are forecasted by taking into account both coal as well as petroleum product prices and demand levels in the industrial and electric sectors. Demand for natural gas in the residential and commercial sectors are not directly dependent upon alternative fuels. The following section contains discussions for crude oil, petroleum products and coal prices used in developing natural gas supply curves for EPA Base Case 2004, v. 2.1.9.

Crude Oil and Petroleum Product Price. Petroleum product prices play an important role in determining the relative mix of fuel (oil, gas, coal) for meeting the end-use demand in the electric and industrial sectors. NANGAS focuses on two petroleum products, No 2 Fuel Oil (distillate) and No. 6 Fuel Oil (residual fuel oil), the latter with two different sulfur levels: low sulfur at 1% weight and high sulfur at 3% weight.

The delivered regional costs for both products are calculated as follows: First, the delivered costs are calculated relative to crude oil prices in the U.S. Gulf. Then, transportation costs between the U.S. Gulf and other regions of the country are calculated.

There are two components for calculating the petroleum product prices delivered to the end-use sector: 1) the price of the petroleum product relative to a reference crude oil price and, 2) the cost of transportation to move the product from the various points of manufacture to the end-use geographic location. Transportation movements are somewhat different for the two products.

Distillate. Distillate products are produced throughout the United States, with the bulk being produced in the large efficient refineries in the Gulf Coast. From the Gulf Coast, pipelines radiate out to the East Coast, the Midwest and the Rockies. Petroleum Administration for Defense Districts (PADD) V, the West Coast region, tends to be a separate market, with some inter-connection between the Rockies and Spokane, and between the Gulf Coast and Arizona. (The entire US is divided into five PADDs, PADD I: East Coast, PADD II: Midwest, PADD III: Gulf Coast, PADD IV: Rocky Mountain, PADD V: West Coast). In addition, the crude oil used on the West Coast tends to differ markedly from that used elsewhere, and product specifications, at least in California, are different.

Residual Fuel Oil. Similar to distillate, residual fuel oil tends to be produced throughout the United States, with the focus on the Mid Atlantic, the Gulf Coast and the West Coast. Movements within the country are constrained by the decreasing demand for residual fuel oil by industry and utilities. Residual fuel oil does not move by pipeline, but by tanker and barge, and occasionally railroad. The majority of movements are directed to the East Coast, the area of greatest use, and where imports play a major role. Similar to the distillate market, the West Coast residual market tends to be separate from the rest of the United States.

For EPA Base Case 2004, v. 2.1.9, ICF has used the West Texas Intermediate (WTI) crude oil price forecast from EIA's AEO 2004 with adjustments for year 2004 based on expected price for year 2004. WTI crude oil is of very high quality and is excellent for refining a larger portion of gasoline. Its API gravity is 39.6 degrees (making it a "light" crude oil), and it contains only about 0.24 percent sulfur (making a "sweet" crude oil). This combination of characteristics, combined with its location, makes it an ideal crude oil to be refined in the U.S.

Refinery margins for the Gulf Coast region were derived from DOE's WORLD model. The WORLD model is a linear programming (LP) model that simulates the total global petroleum supply industry, encompassing crude and non-crude refinery inputs, refinery production, refinery technologies, transportation, product demand, and quality. The refinery margin used for this study reflects the move towards ultra-low sulfur distillate. The regional transportation adders represent both pipeline charges for moving products between different PADDs and charges for trucks and tankers.

Exhibit 15 shows the WTI crude oil price and refinery margins for distillate, 1% residual fuel oil and 3% residual fuel oil used in the study. As can be seen, there will be an increase in the refinery margins for distillates and lowering or leveling-off of refinery margins for residual fuel.

There are many reasons for this phenomenon. Product quality will be a major factor in the future and particularly around 2010. By 2010, the OECD nations and the European Union (EU) will have moved completely to ultra-low sulfur standards, generally less than 10-ppm for diesel and a maximum of 50-ppm for gasoline. Off-road diesel, both in the United States and the EU will also move towards ultra-low sulfur. Non-OECD regions are expected to make moves toward tighter gasoline and diesel quality standards such as:

- Gasoline lead phase-out
- Diesel trends to lower sulfur standards with 500 ppm products becoming common and availability of some ultra low sulfur diesel
- Sulfur standards are projected to tighten for residual fuels.

As the product specifications tighten, the availability of product imports becomes more difficult exerting further upward pressure on the margins. In addition, by 2010 the crude quality entering the U.S. will become heavier and contain more sulfur as imports of heavy crude oil from countries like Canada, Venezuela and Mexico are expected to increase. Therefore, greater processing will be required to upgrade the heavier crude to produce distillates that meet environmental specifications. By the same token, as the incoming crude oil gets heavier, it is easier to producer heavier residual oils.

Exhibit 15: Crude Oil Price Forecast and Refinery Margins

Year	WTI Crude Oil Price, 2003$/bbl	Gulf Coast Refinery Margins (2003$/bbl)		
		Distillate	1% Residual Fuel Oil	3% Residual Fuel Oil
2004	36.6	3.8	-4.1	-5.2
2005	30.9	3.1	-4.5	-5.7
2006	26.4	2.5	-5.0	-6.2
2007	26.6	2.7	-4.8	-6.1
2008	26.8	2.9	-4.5	-6.0
2009	26.9	3.1	-4.3	-5.9
2010	27.1	3.3	-4.1	-5.7
2011	27.3	3.4	-4.4	-6.5
2012	27.5	3.6	-4.8	-7.2
2013	27.7	3.7	-5.1	-7.9
2014	27.8	3.8	-5.5	-8.6
2015	28.0	3.9	-5.8	-9.3
2016	28.2	4.3	-5.8	-9.3
2017	28.4	4.7	-5.7	-9.3
2018	28.6	5.1	-5.7	-9.3
2019	28.8	5.4	-5.7	-9.2
2020	29.0	5.8	-5.7	-9.2
2021	29.2	5.8	-5.7	-9.2
2022	29.4	5.8	-5.7	-9.2
2023	29.6	5.8	-5.7	-9.2
2024	29.8	5.8	-5.7	-9.2
2025	30.0	5.8	-5.7	-9.2
Average (2004-2025)	28.7	4.3	-5.2	-7.9

Coal Price. Average realized regional coal prices, based on actual dispatch and generation patterns of coal plants, are taken directly from IPM outputs for EPA Base Case 2004, v. 2.1.9 and used in NANGAS.

8. End Use Demand Characterization

NANGAS models natural gas demand in four end-use sectors: residential, commercial, industrial and electric generation. For the electric generation sectors both utilities as well as non-utilities are modeled. A total of 139 pipeline corridors connect 83 supply/demand/transfer nodes in the model. Prices are calculated at each of the 83 supply/demand/transfer nodes. The integrating linear program balances supply and demand for gas based on the concept of maximizing consumer and producer surplus in each region, year and season. There are following five key drivers for natural gas demand in NANGAS. They are:

- **i)** **Crude oil price:** Crude oil price is critical because of inter-fuel competition. Industrials and electric utilities can switch between residual fuel oil and distillate as natural gas prices go up. The average crude oil price used for EPA Base Case 2004, v. 2.1.9 is $28.7/bbl (Data for years 2005-2025 was taken from AEO 2004).
- **ii)** **Macroeconmic parameters:** A GDP growth rate of 3% per year was assumed for the U.S., consistent with Bureau of Economic Analysis (BEA). For Canada, a GDP growth rate of 2.3% per year was assumed consistent with Natural Resources Canada (NRCAN) estimates. A population growth rate of 0.85% per year was assumed for the U.S. (source: U.S. Census Bureau) and 0.93% per year for Canada (Source: NRCAN). The number of households and household income are derived from GDP and household size.
- **iii)** **Electric Demand Growth:** Electric sector demand includes utility as well as non-utility generators supplying electricity to the grid. The electric demand growth rate was assumed to be 1.55% per year consistent with IPM Version 2.1.9.
- **iv)** **Pipeline Infrastructure:** New pipeline capacity gets added at 1.25 times the current reservation charges unless another specified rate is known to be more accurate.
- **v)** **Weather:** 30-year normal weather is assumed.

In the following sections, we will describe the modeling methodology, data and updates completed for each of the end-use sector modeling.

Electricity Sector: Electric sector demand for natural gas in NANGAS was set consistent with electric sector assumptions from IPM in order to mimic aggregate regional level IPM decision making with respect to capacity additions, generation levels, heat rates, and costs. In order for NANGAS and IPM to be consistent, key data from IPM were incorporated directly into NANGAS. Entries by IPM demand regions were cross-walked to the corresponding NANGAS demand region to ensure consistency. The main drivers for natural gas demand in the electric sector are the cost and performance data as shown below.

- Electricity generation (BKWH) by region and year
- Average realized heat rates (BTU/KWH) by plant type and year

- Capital cost by plant type and year
- Average realized fixed O&M cost by plant type and year
- Average realized variable O&M cost by plant type and year
- Discount rates
- Capital charge rates
- Maximum utilization of existing and new plants

Utilizing data at this detail in NANGAS helped preserve the detailed power sector dispatch modeling conducted in IPM and captured IPM's forecast of regional and annual gas demand in NANGAS. The overall gas price forecast generated from NANGAS is highly dependent upon the characterization of the electric sector. For example: a higher heat rate assumption for new electric plants would result in higher demand for natural gas and corresponding higher natural gas prices.

Residential Sector: The main drivers for gas consumption in any year for the residential sector are number of household, household income, gas price, energy efficiency, and heating degree-days. The macroeconomic equation was updated based on peer reviewer recommendations, and the final form is shown below.

$$
\begin{aligned}
R_{yr} = R_{0r} &* (P_{yr}/P_{0r})^{(-0.598)} \\
&* (HH_{yr}/HH_{0r}) * (HHI_{yr}/HHI_{0r})^{(0.680)} \\
&* (HDD_{yr}/HDD_{0r})^{(0.276)} \\
&* (R_{eff_{yr}} / R_{eff_{0r}})
\end{aligned}
$$

The equation was econometrically derived using price, demand, and heating degree-days data from 1977-2002 on individual state level data. Number of U.S. households and population data from 1967-2002 were used to derive an equation to forecast number of households in the future. In the above equation the terms are defined as follows:

R – Natural gas demand for the residential sector
P – Natural gas price for the residential sector
HH – Number of households
HHI – Average household income
Reff – Residential efficiency improvement factor
HDD – Heating degree-days

Subscripts notation are as follows: r – Region, y – Year, 0 – Reference year.

The residential demand equation indicates that the price elasticity of demand is -0.598. This means that when the natural gas price changes by 100%, residential demand for gas will change by approximately 60%. Natural gas demand in the residential sector also increases as the number of households and household income increases. In addition, heating degree-days play an important role in determining the residential gas demand level. Efficiency improvements play a critical role in determining residential demand level. The American Gas Association (AGA) reports that the average home uses 22% less gas than it did in 1980. So the total amount of natural gas delivered to homes in 2002, was about the same as the amount of natural gas delivered in 1997, despite the fact that seven million residential customers were added during that time.

This has happened for efficiency improvements in the industry. Residential efficiency improvement factor used in NANGAS is 1.7% per year.

The number of households and household income is forecasted as follows. First, average national household size (HHS) is forecasted using the following equation.

$$HHS_y = Exp(0.873249 + 4.74279 * (1/(y-1953)))$$

The average household size has been decreasing in the U.S. from a high of 3.2 individuals per household in 1967 to around 2.6 individuals per household currently. This equation fits the historical trend well and forecasts a gradual decline in the household size to around 2.4 by 2025.

Population is then divided by the household size to generate the number of households (HH). Gross regional product is divided by the household size to determine average household income (HHI). Number of households and household income are both used in determining residential demand for natural gas.

For forecasting purposes, a normal weather is assumed. Natural gas price delivered to the residential sector is calculated endogenously in NANGAS via the integrating linear program.

Commercial Sector: The main drivers for gas consumption in any year for the commercial sector are gross regional product, price and heating degree-days. The macroeconomic equation used in NANGAS was updated based on peer reviewer recommendations, and the final form is shown below.

$$\begin{aligned} C_{yr} = C_{0r} &* (P_{yr}/P_{0r})^{(-0.424)} \\ &* (GRP_{yr}/GRP_{0r})^{0.256} \\ &* (HDD_{yr}/HDD_{0r})^{0.191} \end{aligned}$$

The equation was econometrically derived using price, demand, and heating degree-days data from 1977-2002 on individual state level data. It was determined that efficiency improvements in the commercial sector did not factor into overall demand levels. In the above equation the terms are defined as follows:

C – Natural gas demand for the commercial sector
P – Natural gas price for the commercial sector
GRP – Gross regional product
HDD – Heating degree-days

Subscripts notation are as follows: r – Region, y – Year, 0 – Reference year.

The commercial demand equation indicates that the price elasticity of demand is -0.424. This means that when natural gas price changes by 100%, the commercial demand for natural gas will change by 42.4%. Natural gas demand in the commercial sector also increases as the gross regional product increases. In addition, heating degree-days play an important role in determining the commercial sector gas demand level. As previously noted, efficiency improvements don't play a critical role in determining the commercial demand for natural gas.

For forecasting purposes, normal weather is assumed. Natural gas price delivered to the commercial sector is calculated endogenously in NANGAS via the integrating linear program.

Industrial Sector: Gas demand in the industrial sector is modeled in NANGAS for three sub-sectors. They are: boilers, process heat/other and feedstock. The representation of process heat and feedstock sub-sectors was updated considerably based on peer review recommendations.

Industrial Boilers: In the industrial boiler sector, NANGAS contains over 30,000 boilers. The basic operating characteristics of the boilers are derived from EPA's AIRS database. In NANGAS, the industrial boilers can switch between natural gas and fuel oil depending upon the relative attractiveness of the fuel prices.

Industrial boilers are divided into two broad categories: small boilers with capacity less than 250 MMBtu/hr and large boilers with capacity greater than 250 MMBtu/hr. In both categories, there are three types of boilers; boilers that burn "gas only", "gas or resid" and "gas or distillate". Altogether there are six separate combinations of boiler size – fuel type modeled in NANGAS.

Two separate macroeconomic equations are used to forecast gas demand in the industrial sector. The two equations are based on the two types of fuels used in industrial boilers.

For gas-only burning units (no fuel switching), the main drivers for gas demand are Gross Regional Product (GRP, forecasted to be growing at 3%/year), energy intensity (which is defined as a ratio of industrial sector output to GRP, forecasted to be decreasing at 1.1% per year), and the gas price (calculated internally within the model). The macroeconomic equation used to forecast natural gas demand for gas-only burning boilers is as follows:

$$\begin{aligned} BG_{yr} = BG_{0r} &*(P_{yr}/P_{0r})^{(-0.74)} \\ &*(GRP_{yr}/GRP_{0r})^{(0.48)} \\ &*(EI_{yr}/EI_{0r})^{(2.11)} \end{aligned}$$

Efficiency improvements in the boiler sector are captured through energy intensity. Energy intensity is projected to decline at an average annual rate of 1.1% per year, as continuing efficiency gains and structural shifts in the economy offset growth in demand for energy services. In the above equation the terms are defined as follows:

BG – Natural gas demand for gas-only industrial boilers
P – Natural gas price for the industrial sector
GRP – Gross regional product
EI – Energy intensity

Subscripts notation are as follows: r – Region, y – Year, 0 – Reference year.

For gas/distillate and gas/residual fuel oil burning units, the regression equation is similar to the gas-only burning units but the price term in the equation is not only based on the gas price, but it also is a function of the price of the alternative fuel to gas (either residual fuel oil or distillate). If the price of the alternative fuel is cheaper than natural gas, then gas demand for boilers is zero, and the boilers burn the fuel oil and vice versa. This comparison is done on an annual and seasonal basis in NANGAS. The macroeconomic equations used to forecast natural gas demand for gas/oil fungible boilers are as follows:

When gas prices are lower than fuel oil price:

$$BG_{yr} = BG_{0r} *(P_{yr}/P_{0r})^{(-0.74)} *(GRP_{yr}/GRP_{0r})^{(0.48)} *(EI_{yr}/EI_{0r})^{(2.11)}$$

$$BF_{yr} = 0.0$$

When gas prices are higher than fuel oil price:

$$BF_{yr} = BF_{0r} *(FP_{yr}/FP_{0r})^{(-0.42)} *(GRP_{yr}/GRP_{0r})^{(1.54)} *(EI_{yr}/EI_{0r})^{(2.28)}$$

$$BG_{yr} = 0.0$$

In the above equations the terms are defined as follows:

BG – Natural gas demand for industrial boilers
BF – Fuel oil demand for industrial boilers
P – Natural gas price for the industrial sector
FP – Fuel oil price for the industrial sector
GRP – Gross regional product
EI – Energy intensity

Subscripts notation are as follows: r – Region, y – Year, 0 – Reference year.

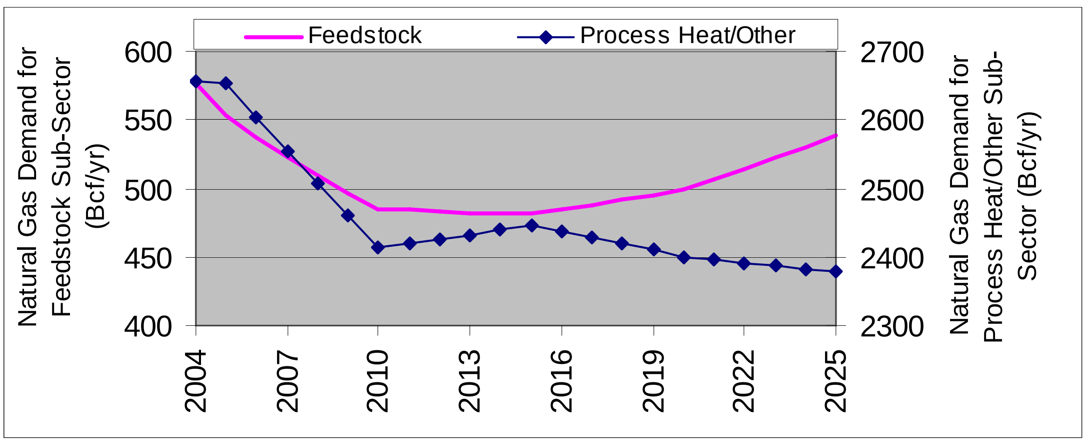
Process Heat/Other and Feedstock Sub-Sectors: Process heat and feedstock sub-sectors' natural gas demand is exogenously supplied as inputs in NANGAS.

"Process heat" includes all uses of energy that involves direct heating (instead of indirect heating like steam) while "Other" includes all the remaining direct heating uses, including non-boiler cogeneration, on-site electricity generation, and space heating.

The feedstock sub-sector of the industrial sector consists of three subcomponents: ammonia, methanol and hydrogen production. The domestic ammonia industry is highly affected by high natural gas prices as natural gas accounts for a substantial share of its total production costs. Further, the industry is exposed to global market competition, so permanent loss of domestic production due to increased imports is possible.

In NANGAS, price effects on natural gas demand from both the feedstock and process heat/other sub-sectors have not been represented. The peer review process suggested capturing such price effects by developing macroeconomic equations for use in forecasting gas demand in these sub-sectors. After extensive data research, it was determined that data on historical, regional natural gas demand for these sub-sectors are not publicly available or available for purchase. In the absence of historical data, it was not possible to develop macroeconomic equations. Instead, the latest natural gas demand forecasts for the feedstock and process heat/other sub-sectors were obtained from NPC and exogenously supplied to NANGAS.   The NPC forecast reflects the near term loss of natural gas demand in fertilizer and other energy intensive industries and forecasts a gradual reduction in demand. Exhibit 16 shows gas demand data used in NANGAS for these sub-sectors.

Exhibit 16: Assumption for Natural Gas Demand in Process Heat/Other and Feedstock Sub-Sectors



9.   Discussion of Final NANGAS Results

In this section we describe NANGAS results for EPA Base Case 2004, v. 2.1.9. A typical NANGAS run generates the following outputs:

- Natural gas prices
- Natural gas production by region, resource type
- Natural gas industry activities such as reserves additions, wells drilled, success rates, pipeline utilization and flows
- Natural gas consumption by region and sector (i.e., the electric sector and the non-electric sector, which includes residential, commercial and industrial sectors)
- Pipeline capacity expansion levels, electricity capacity expansion levels

Four NANGAS runs were completed at four different electricity growth rates (1.0%, 1.55%, 1.74% and 2.5%) that provided seed prices and volumes to generate the supply curves for IPM Version 2.1.9. The following discussion covers the results for the 1.55% electricity growth rate case. Supply/Demand disposition and prices for the other three cases are shown later in this section. Summary results for the 1.55% electricity growth rate case are shown in Exhibit 17.

Exhibit 17: Supply/Demand Disposition and Henry Hub Price for the 1.55% electricity growth rate case used to build the natural gas supply curves for EPA Base Case 2004, v. 2.1.9

Supply/Demand Disposition, 1.55% Case, Bcf/yr	2005	2007	2009	2010	2011	2012	2014	2015	2018	2019	2020	2023	2024	2025	Annual Growth (%) (2005-2025)
Northeast	1050	1146	1283	1383	1457	1474	1434	1465	1675	1726	1760	1867	1864	1887	2.4%
Gulf Coast (Onshore)	5106	4954	4760	4681	4582	4516	4482	4563	4989	5079	5114	4735	4555	4360	-0.6%
Gulf Offshore	5320	5463	5479	5544	5618	5606	5791	5766	6004	6200	6350	6803	6979	7077	1.1%
Mid-Continent	2563	2458	2328	2296	2289	2257	2125	2056	2054	2050	2002	2111	2156	2186	-0.6%
Permian	1669	1595	1602	1613	1636	1649	1724	1746	1809	1807	1807	1754	1726	1690	0.1%
Rocky Mountain/West Coast	3291	3556	3980	3912	4140	4353	4811	5019	5288	5597	5796	6312	6653	6580	2.8%
North Alaska	0	0	0	0	0	0	0	1497	1685	1896	1896	1896	1896	1896	NA
Total L-48	18999	19172	19431	19428	19721	19854	20367	20615	21818	22460	22829	23581	23934	23780	0.9%
Total US	18999	19172	19431	19428	19721	19854	20367	22112	23502	24356	24725	25477	25830	25676	1.2%
Imports from Eastern and Western Canada	3569	3391	3697	3542	3365	3435	3433	2397	2510	2185	1984	1814	1790	1753	-2.8%
LNG Imports to US	664	927	1219	1219	1467	1511	1511	1511	1511	1511	1767	2131	2132	2132	4.8%
Net Exports to Mexico	587	454	351	308	286	266	230	214	172	160	149	128	121	115	-6.3%
TOTAL L-48 Supply Available	22645	23035	23997	23880	24267	24534	25080	25806	27351	27892	28326	29295	29630	29446	1.1%
U.S. Demand, Non-Electric Sector	17711	17905	18520	18260	18343	18268	18558	18894	19222	19317	19303	19225	19278	18920	0.3%
U.S. Demand, Electric Sector	4934	5130	5476	5621	5924	6265	6523	6911	8129	8575	9023	10071	10353	10526	3.1%
Total Canadian Demand	2990	3074	3281	3292	3330	3372	3528	3620	3945	3921	3952	4205	4298	4332	1.5%
	2005	**2007**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2018**	**2019**	**2020**	**2023**	**2024**	**2025**	**Average Price (2005-2025)**
Henry Hub, 2003$/MMBtu	**3.73**	**3.54**	**3.23**	**3.44**	**3.46**	**3.58**	**3.53**	**3.41**	**3.40**	**3.45**	**3.54**	**3.71**	**3.78**	**4.07**	**3.53**

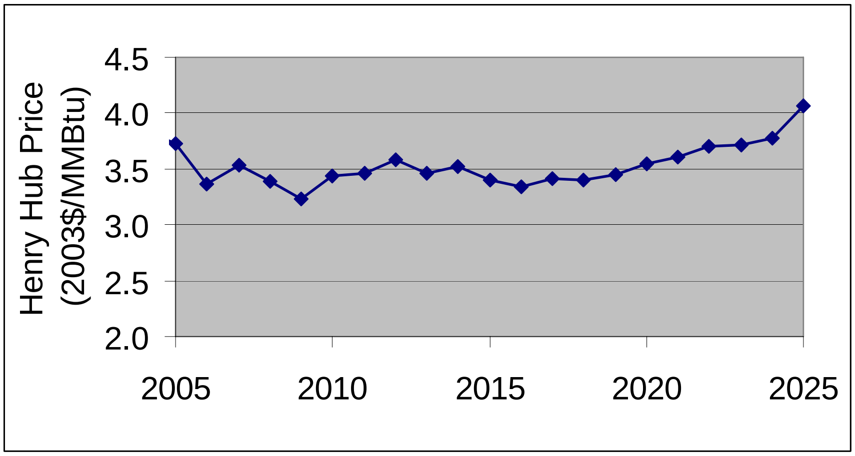
Natural Gas Prices. Representative North American wellhead prices are typically reported at the Henry Hub. Henry Hub is a pipeline interchange hub in Louisiana Gulf Coast near Erath, LA, where eight interstate and three intrastate pipelines interconnect. Liquidity at this point is very high and it serves as the primary point of exchange for the New York Mercantile Exchange (NYMEX) active natural gas futures markets. Henry Hub prices are considered as a proxy for U.S. natural gas prices. Natural gas from the Gulf moves through the Henry Hub onto long-haul interstate pipelines serving demand centers. Due to the importance and significance of the Henry Hub, NANGAS generated supply curves are specified at Henry Hub prices.

Henry Hub prices stay above $3.50/MMBtu in real 2003$ for the entire forecasting horizon, except when Alaskan and Mackenzie Delta gas enters the marketplace (see Exhibit 18). High prices in the next few years (around $3.75/MMBtu) reflect the current situation of tight gas supplies and the marginal supply response of drilling activities. Higher prices trim demand growth and bring forth additional supply. This keeps the prices from rising appreciably until around 2018. Increase in Henry Hub price after 2018 is driven by demand growth, primarily electric sector demand for natural gas. Average natural gas price for 2005-2025 timeframe is $3.53/MMbtu.

A decrease in price until year 2009 is due to gas supply outstripping growth in demand. Total demand increases by 1.3% from year 2004 to year 2009 (from 22.5 Tcf to 24.0 Tcf) but total L-48 production and LNG supplies increase by around 1.5%/yr. In year 2009, prices go down due to additional LNG volumes in the Gulf, an increase in L-48 production due to higher prices in earlier years, and introduction of gas from the Mackenzie Delta (1.2 Bcf/d). Another dip in prices is observed when Alaska comes online in year 2015.

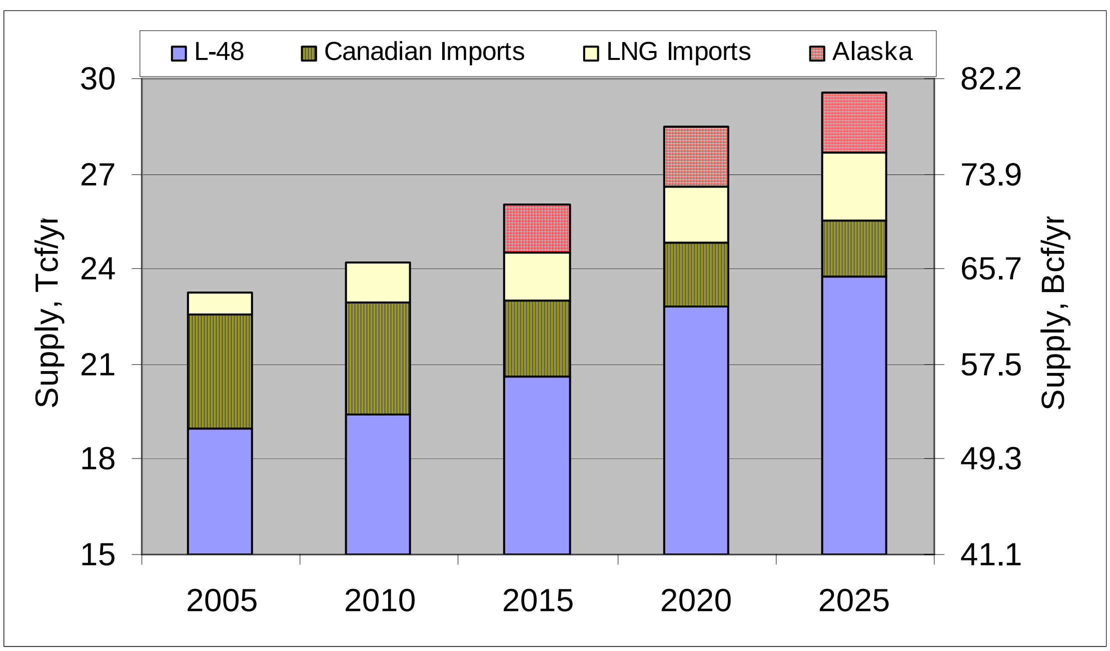
Even at the moderate price of around $3.50/MMBtu, U.S. total natural gas demand never reaches 30 Tcf/yr (82.2 Bcf/d). This is because the electricity sector demand growth is a modest 1.55% per year, coal usage for the electricity sector continues to increase, and petroleum products, not just natural gas, are used throughout the modeling horizon in the industrial as well as the electricity sectors.

Exhibit 18: Henry Hub Price Forecast



Total Supply: Total supply comes from three sources: production from natural gas fields located in L-48, Canadian imports, Alaska and LNG imports. Mexico is assumed to be a small net importer and does not impact the overall pricing levels. Exhibit 19 shows supply from these sources.

Exhibit 19: Supply Sources for L-48

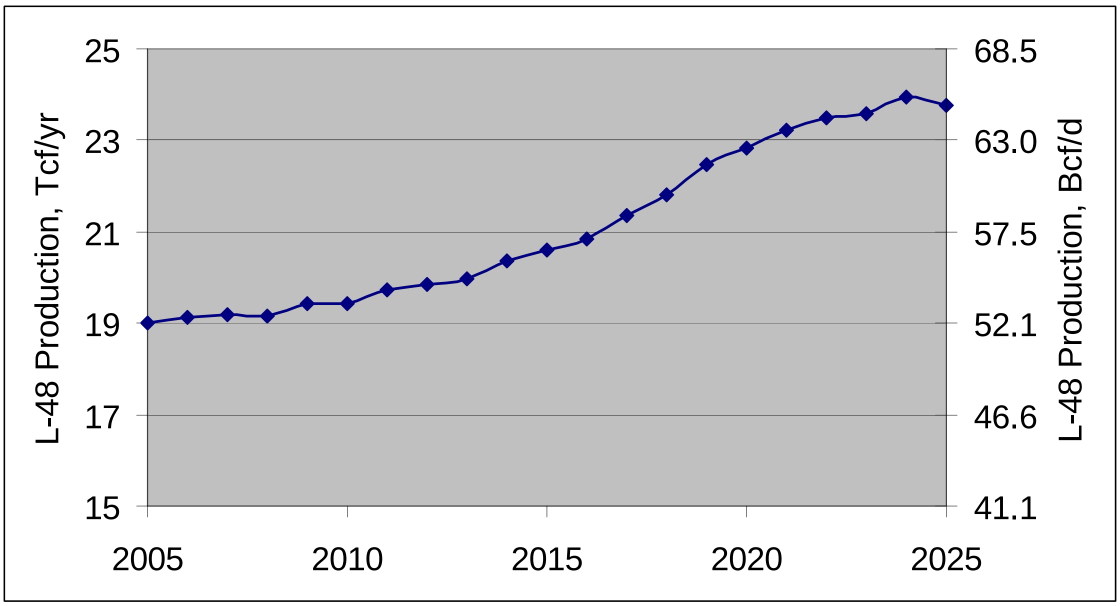


NANGAS forecasts that the L-48 fields will respond to the sustained natural gas prices of $3.50/MMBtu or higher. L-48 production will grow at an annual rate of around 1% per year. In the near term (2005-2008), however, NANGAS forecasts a flat production outlook.

Even at this growth rate, L-48 production will be able to meet only around 80% of projected natural gas demand. The remaining 20% will be met by increasing LNG, Alaska and Canadian imports.

a) L-48 Production and Regional Trends L-48 production, an output of NANGAS, grows from 19 Tcf/yr (52 Bcf/d) in year 2005 to 23.8 Tcf/yr (65.2 Bcf/d) in 2025. This is a modest growth of around 1% per year (see Exhibit 20). As higher amounts of LNG are introduced in the marketplace, prices are reduced, which in turn reduces production. L-48 production grows at 0.6%/yr until 2010, but grows at 1.4%/yr from 2010-2025 timeframe.

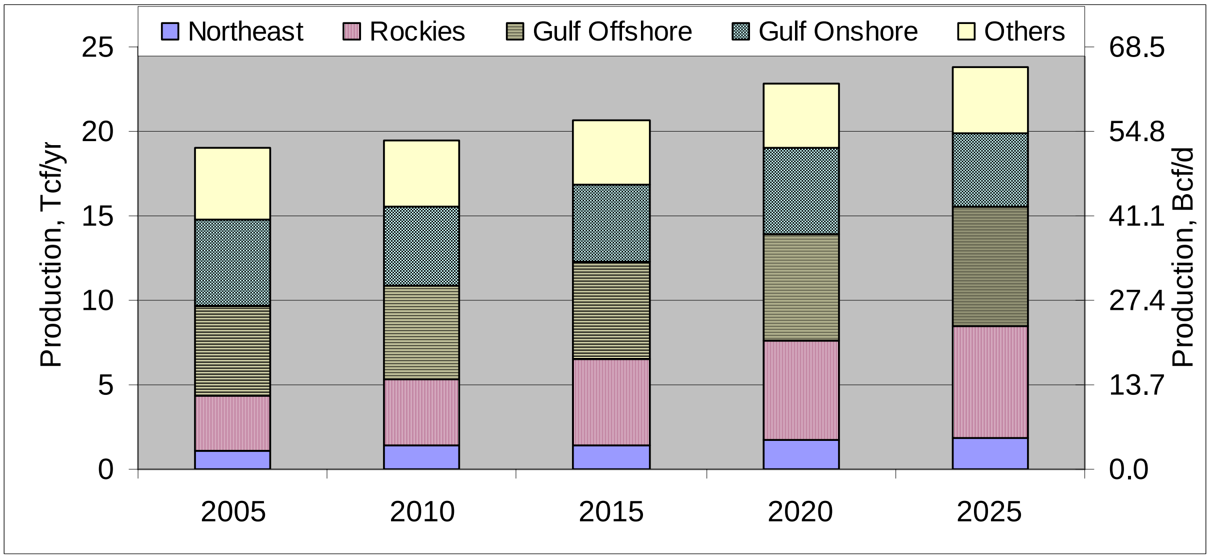
Exhibit 20: Annual Total L-48 Production Forecast



Regions with supply growth are: Rockies, Northeast and Gulf Offshore. NANGAS forecasts around 2.7% per year growth in production from Rockies, and 2.4% per year from Appalachia. NANGAS is bullish on production from coalbed methane and tight gas resources from these regions as forecasted prices support higher exploration and development activities in the region.

Gulf offshore supplies remain flat in the near term and then grow at around 1.0%/yr as additional volumes are brought online from deepwater and deep shelf resources. NANGAS forecasts a continuing decline in onshore Gulf Coast and Mid-Continent supply regions as basins mature in the region and additional drilling in the region bring lower productive fields to the market. Permian basin remains almost flat during the forecast horizon. Exhibit 21 shows regional production trends.

Exhibit 21: L-48 Regional Production Trends



b) Canadian and LNG Imports and Exports to Mexico: The model endogenously calculates LNG and Canadian imports by year. Exhibit 22 shows Canadian and LNG import levels.

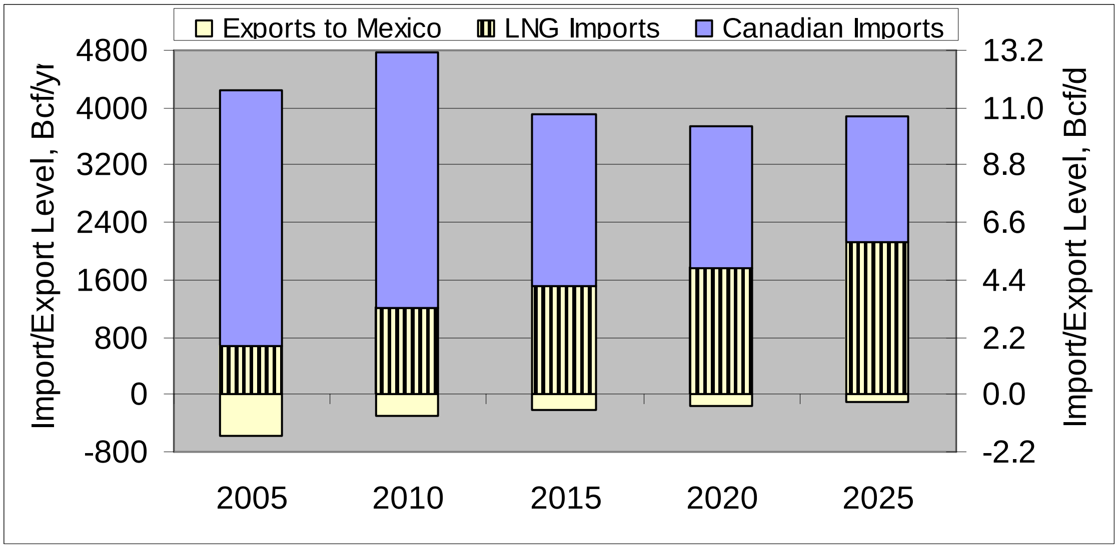
Western Canadian Sedimentary Basin (WCSB) declines on average by 1% per year throughout the forecasting horizon. During the later timeframe (after 2020), production in WCSB starts to increase due to unconventional tight and coalbed methane gas production activities.

Currently, around 83% of total U.S. demand is met by L-48 production, 15% by Canadian imports and 2% by LNG. By 2025, the L-48 production can only meet 80% of projected U.S. demand for natural gas. Imports from Canada continue to decline and contribute to only 6% of total U.S. demand by 2025. On average, net Canadian imports decline by 3.0% per year (from 3.6 Tcf/yr or 9.9 Bcf/d in 2004 to 1.8 Tcf/yr or 4.8 Bcf/d in 2025). LNG imports rise and fill this widening gap, meeting over 7.0% of U.S. demand by 2025. Alaskan supplies serve the remaining 7%.

All existing LNG terminals operate to 85% capacity, and new terminals are built and operate to capacity in Bahamas, and Gulf Coast at pricing thresholds of $3.00 - $3.50/MMBtu. LNG volumes increase at over 7% per year from 1.32 Bcf/d in 2004 to 5.8 Bcf/d in year 2025. NANGAS shows significant increases in Gulf Coast LNG from around 0.53 Bcf/d in 2004 to around 3.3 Bcf/d in 2025.

Mexico is assumed to be a net importer for the entire forecasting horizon. For EPA Base Case 2004, v. 2.1.9, export levels to Mexico from US have been taken from AEO 2004 forecasts. Exports to Mexico from US continue to decrease over the forecasting horizon.

Exhibit 22: Canadian and LNG Import Levels and Exports to Mexico



(c) L-48 Demand: Total L-48 natural gas demand grows from around 22.6 Tcf/yr (62.1 Bcf/d) in 2005 to 29.4 Tcf/yr (80.7 Bcf/d) in 2025. This is a modest growth of around 1.1% per year. Total demand never reaches 30 Tcf throughout the modeling horizon. Canadian demand grows by 1.5% per year from around 3.0 Tcf/yr (8.2 Bcf/d) in 2005 to 4.3 Tcf/yr (11.9 Bcf/d) in year 2025.

Natural gas demand in the core residential and commercial sectors in L-48 grows by 0.2% per year. Gas demand in the industrial sector remains almost flat throughout the modeling horizon. Total L-48 demand for natural gas in the electric sector grows at 3.1% per year.

The three other electricity growth rate cases are summarized in Exhibits 23, 24, and 25.

Exhibit 23: Supply/Demand Disposition and Henry Hub Price for 1.0%/Year Electricity Growth Rate

Supply/Demand Disposition, 1.0% Case, Bcf/yr	**2005**	**2007**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2018**	**2019**	**2020**	**2023**	**2024**	**2025**	**Annual Growth (%) (2005-2025)**
Northeast	1042	1142	1275	1373	1446	1459	1418	1449	1642	1689	1722	1821	1817	1822	2.3%
Gulf Coast (Onshore)	5101	4951	4756	4677	4579	4508	4471	4543	4906	4969	4992	4646	4480	4284	-0.7%
Gulf Offshore	5315	5459	5477	5543	5616	5605	5789	5764	5973	6172	6330	6803	6949	7014	1.1%
Mid-Continent	2558	2453	2323	2293	2284	2249	2119	2051	2032	2024	1976	2075	2110	2145	-0.7%
Permian	1665	1591	1599	1611	1634	1644	1721	1743	1797	1790	1784	1731	1708	1675	0.0%
Rocky Mountain/West Coast	3288	3554	3979	3910	4135	4349	4846	5079	5252	5508	5680	6094	6352	6337	2.7%
North Alaska	0	0	0	0	0	0	0	1497.4	1685	1896	1896	1896	1896	1896	NA
Total L-48	18969	19149	19409	19407	19693	19814	20363	20629	21602	22152	22483	23170	23414	23277	0.8%
Total US	18969	19149	19409	19407	19693	19814	20363	22127	23286	24048	24380	25066	25310	25173	1.1%
Imports from Eastern and Western Canada	3553	3368	3672	3507	3355	3412	3391	2352	2342	1987	1802	1593	1568	1533	-3.3%
LNG Imports to US	664	927	1219	1219	1219	1219	1219	1219	1219	1219	1219	1290	1467	1767	4.0%
Net Exports to Mexico	587	454	351	308	286	266	230	214	172	160	149	128	121	115	-6.3%
TOTAL L-48 Supply Available	22598	22990	23949	23825	23981	24179	24743	25484	26675	27094	27252	27821	28224	28357	0.9%
U.S. Demand, Non-Electric Sector	17695	17928	18562	18323	18278	18246	18670	19165	19755	19897	19767	19483	19585	19461	0.4%
U.S. Demand, Electric Sector	4904	5062	5387	5502	5703	5933	6073	6320	6920	7197	7485	8338	8640	8897	2.4%
Total Canadian Demand	2988	3076	3286	3305	3321	3372	3546	3643	3989	4004	4016	4233	4337	4399	1.6%
	2005	**2007**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2018**	**2019**	**2020**	**2023**	**2024**	**2025**	**Average Price (2005-2025)**
Henry Hub, 2003$/MMBtu	**3.75**	**3.52**	**3.21**	**3.38**	**3.51**	**3.59**	**3.45**	**3.23**	**3.06**	**3.06**	**3.19**	**3.45**	**3.45**	**3.58**	**3.37**

Exhibit 24: Supply/Demand Disposition and Henry Hub Price for 1.74%/Year Electricity Growth Rate

Supply/Demand Disposition, 1.74% Case, Bcf/yr	2005	2007	2009	2010	2011	2012	2014	2015	2018	2019	2020	2023	2024	2025	Annual Growth (%) (2005-2025)
Northeast	1043	1152	1285	1386	1462	1487	1442	1489	1720	1778	1812	1936	1937	1946	2.5%
Gulf Coast (Onshore)	5103	4958	4774	4703	4614	4553	4528	4626	5059	5151	5180	4798	4627	4444	-0.6%
Gulf Offshore	5315	5462	5480	5545	5617	5605	5791	5785	6011	6203	6351	6870	7046	7114	1.2%
Mid-Continent	2559	2455	2329	2302	2294	2274	2188	2118	2070	2072	2027	2137	2188	2223	-0.6%
Permian	1665	1594	1604	1619	1646	1658	1737	1760	1833	1835	1832	1768	1745	1708	0.1%
Rockies Mountain/West Coast	3287	3554	3982	3895	4144	4387	4963	5169	5293	5561	5774	6318	6729	6680	2.9%
North Alaska	0	0	0	0	0	0	0	1497	1685	1896	1896	1896	1896	1896	NA
Total L-48	18972	19175	19454	19449	19778	19964	20647	20947	21986	22601	22976	23826	24271	24115	1.0%
Total US	18972	19175	19454	19449	19778	19964	20647	22444	23670	24497	24872	25722	26167	26011	1.3%
Imports from Eastern and Western Canada	3562	3424	3750	3570	3405	3474	3504	2688	2761	2347	2214	2027	2017	1986	-2.3%
LNG Imports to US	664	927	1219	1584	1767	1767	1767	1767	1767	1849	2132	2132	2132	2132	4.8%
Net Exports to Mexico	587	454	351	308	286	266	230	214	172	160	149	128	121	115	-6.3%
TOTAL L-48 Supply Available	22610	23072	24072	24295	24664	24938	25688	26685	28026	28534	29069	29753	30194	30014	1.1%
U.S. Demand, Non-Electric Sector	17698	17665	18187	18175	18220	18141	18313	18713	18873	18965	19060	18779	18798	18507	0.2%
U.S. Demand, Electric Sector	4912	5407	5885	6119	6443	6797	7375	7972	9153	9568	10010	10974	11396	11507	3.5%
Total Canadian Demand	2987	3038	3239	3281	3313	3356	3481	3617	3919	3868	3915	4093	4167	4203	1.4%
	2005	**2007**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2018**	**2019**	**2020**	**2023**	**2024**	**2025**	**Average Price (2005-2025)**
Henry Hub, 2003$/MMBtu	**3.74**	**3.71**	**3.44**	**3.48**	**3.53**	**3.67**	**3.74**	**3.56**	**3.67**	**3.71**	**3.73**	**4.07**	**4.16**	**4.45**	**3.74**

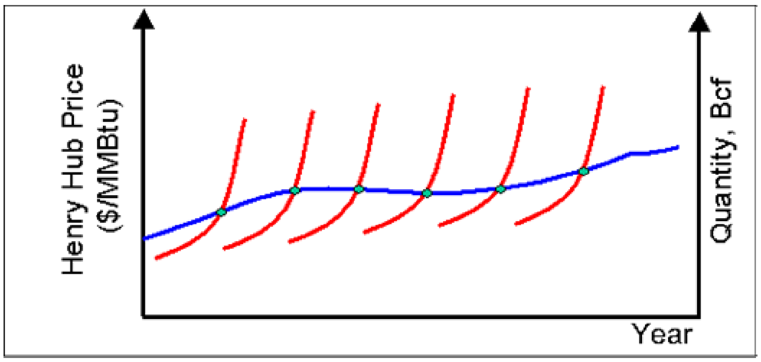
Exhibit 25: Supply/Demand Disposition and Henry Hub Price for 2.5%/Year Electricity Growth Rate

Supply/Demand Disposition, 2.5% Case, Bcf/yr	2005	2007	2009	2010	2011	2012	2014	2015	2018	2019	2020	2023	2024	2025	Annual Growth (%) (2005-2025)
Northeast	1040	1153	1293	1397	1477	1514	1491	1539	1782	1845	1899	2059	2047	2050	2.8%
Gulf Coast (Onshore)	5101	4960	4784	4718	4637	4582	4560	4668	5114	5216	5261	4903	4742	4555	-0.5%
Gulf Offshore	5314	5462	5482	5546	5618	5607	5813	5806	6060	6274	6436	6914	7062	7147	1.2%
Mid-Continent	2558	2454	2337	2304	2301	2304	2219	2144	2153	2151	2103	2185	2241	2280	-0.5%
Permian	1665	1594	1611	1628	1655	1671	1750	1780	1854	1856	1851	1788	1772	1735	0.2%
Rocky Mountain/West Coast	3287	3555	3983	3893	4133	4378	4959	5172	5350	5629	5935	6691	6999	6893	3.0%
North Alaska	0	0	0	0	0	0	0	1497	1685	1896	1896	1896	1896	1896	NA
Total L-48	18964	19177	19489	19486	19822	20055	20791	21108	22312	22971	23485	24539	24863	24660	1.1%
Total US	18964	19177	19489	19486	19822	20055	20791	22605	23997	24867	25381	26435	26759	26556	1.4%
Imports from Eastern and Western Canada	3553	3438	3787	3630	3463	3519	3616	3331	3160	2872	2729	2489	2458	2397	-1.6%
LNG Imports to US	664	927	1402	1584	1767	1949	1949	1949	2132	2132	2132	2132	2132	2132	4.8%
Net Exports to Mexico	587	454	351	308	286	266	230	214	172	160	149	128	121	115	-6.3%
TOTAL L-48 Supply Available	22594	23087	24327	24392	24765	25257	26126	27671	29116	29710	30092	30928	31228	30970	1.3%
U.S. Demand, Non-Electric Sector	17689	17493	17964	17798	17869	17877	17767	18463	18375	18380	18387	18319	18339	18189	0.1%
U.S. Demand, Electric Sector	4905	5595	6363	6594	6897	7380	8359	9208	10741	11330	11705	12609	12888	12781	3.9%
Total Canadian Demand	2981	3007	3200	3229	3267	3317	3375	3608	3725	3751	3765	3945	4017	4061	1.2%
	2005	**2007**	**2009**	**2010**	**2011**	**2012**	**2014**	**2015**	**2018**	**2019**	**2020**	**2023**	**2024**	**2025**	**Average Price (2005-2025)**
Henry Hub, 2003$/MMBtu	**3.75**	**3.85**	**3.58**	**3.73**	**3.77**	**3.86**	**4.18**	**3.78**	**4.14**	**4.26**	**4.35**	**4.57**	**4.68**	**4.89**	**4.08**

10. Supply Curves, Transportation Adders for EPA Base Case 2004, v. 2.1.9

For use in IPM modeling, NANGAS generates a price forecast over a time horizon and a set of time dependent price/supply curves based on the resulting price path for each year in the forecast. Exhibit 26 shows a schematic of this methodology.

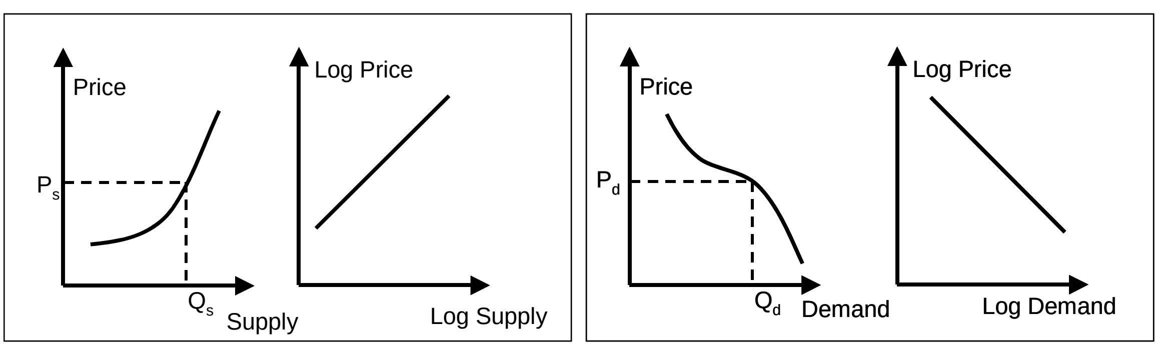
Exhibit 26: Schematic of Price Path and Time Dependent Supply Curves Generated in NANGAS



Supply Curve Generation Steps**:** NANGAS and IPM are run at four different electricity growth rates to generate seed points of the supply curves. NANGAS and IPM runs are iterated until the results converge for electric sector gas consumption and for clearing prices in each of the four electricity growth rate cases. This results in four final convergent NANGAS runs, one for each electricity growth case. For EPA Base Case 2004, v. 2.1.9, the four electricity growth rates assumed are: 1.0%, 1.55%, 1.74% and 2.5%.

Supply/price relationship and non-electric demand/price relationships are curve-fit on a log-log scale. As Exhibit 27 shows the price/quantity pair when plotted on log-log scale is assumed to follow a straight line.

Exhibit 27: NANGAS Assumption of the Inter-relation of Price/Quantity on Cartesian and Log-Log Scale



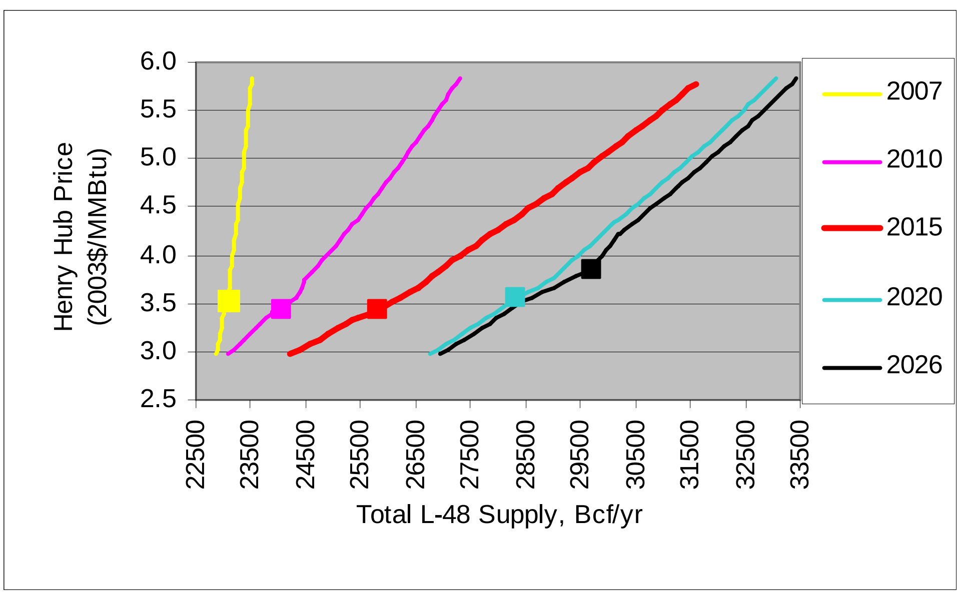
There is an inelastic portion and an elastic portion of the supply and demand curve, which is assumed to approximate a linear relation when plotted on a log-log scale. Slopes and intercepts are calculated for every year based on the four points obtained from the four growth rate cases. The resulting equation is used in deriving the curves at every $0.05/MMBtu interval.

Supply Curves: IPM's run years for EPA Base Case 2004, v.2.1.9 are 2007, 2010, 2015, 2020 and 2026. NANGAS produces results for every year from 2005 to 2025, balancing supply/demand and transportation in generating clearing natural gas prices. To generate prices and supply curves for IPM, NANGAS run year results are weight averaged to generate data for IPM, according to the following scheme.

IPM run year 2007: NANGAS run year 2007
IPM run year 2010: Weight average of prices and supply for years 2008-2012
IPM run year 2015: Weight average of prices and supply for years 2013-2017
IPM run year 2020: Weight average of prices and supply for years 2018-2022
IPM run year 2026: Weight average of prices and supply for years 2023-2025
(Since NANGAS is not run for year 2026, the average of 2023 to 2025 is used for IPM run year 2026.)

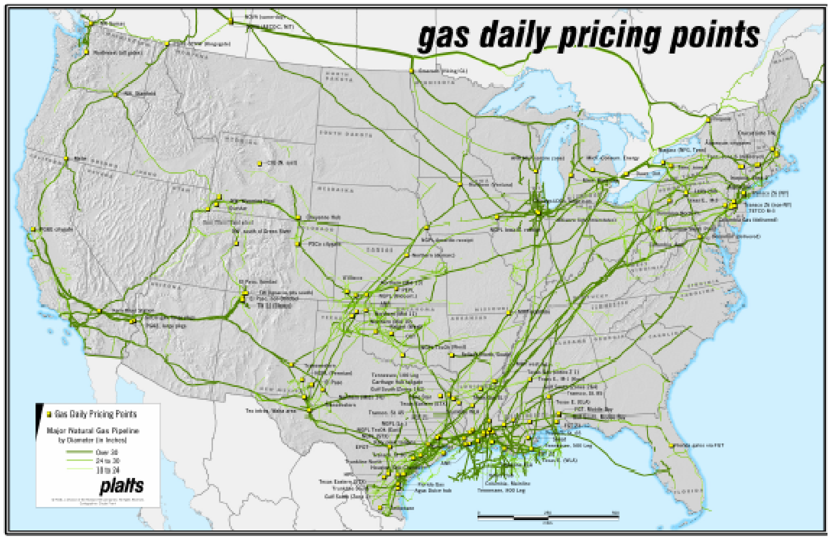
The final resulting supply curves developed for years 2007, 2010, 2015, 2020 and 2026 are shown in Exhibit 28. Exhibit 28 also shows the converged gas price for EPA Base Case 2004, v. 2.1.9 for the years. As expected, supply curves for early years are steeper compared to later year supply curves. For example, the supply curve for year 2007 (shown in yellow) indicates that supply cannot be increased substantially (increase is from 22.9 Tcf to 23.5 Tcf which represents a modest increase of 2.8%) as prices increase from around $3.00/MMBtu to over $5.50/MMBtu. The reason is that a substantial increase in gas price for year 2007 will not result in any substantial increase in L-48 production, imports etc, as substantial supply increases need lead times. (For example, a new LNG terminal takes over 4 years to get certificated and built.) After year 2010, there are substantial increases in supplies in response to increases in prices. For example, in year 2020 if prices rise from $3.00/MMBtu to over $5.50/MMBtu, supply would increase from 26.8 Tcf to 33.1 Tcf (an increase of almost 25%).

Exhibit 28: Supply Curves for Years 2007, 2010, 2015, 2020 and 2026 and Natural Gas Price



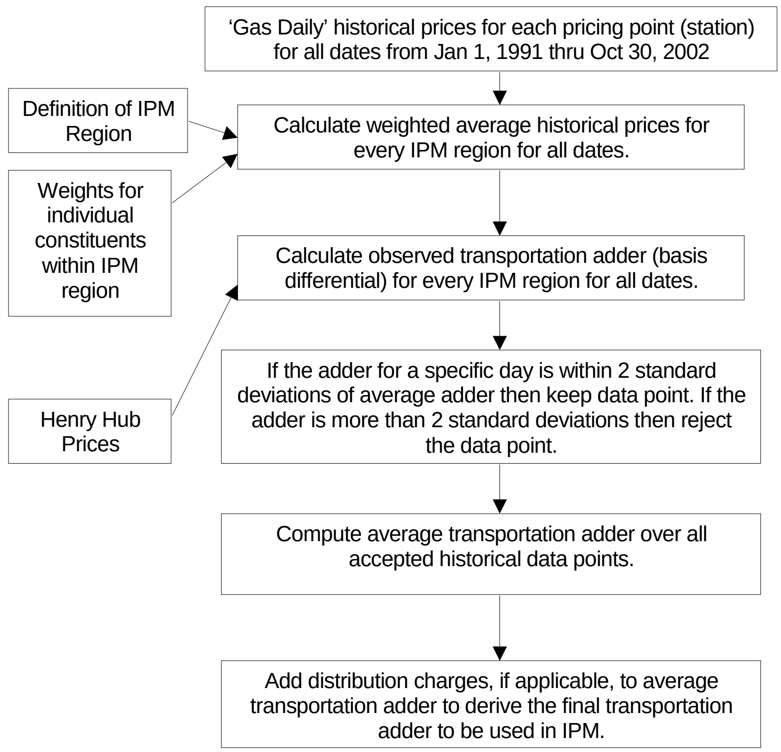
Transportation Adders: To populate IPM with observed basis differentials or transportation adders, ICF analyzed Platt's "Gas Daily" reported gas pricing data at approximately 100 pricing points, and selected one and/or a combination of gas daily pricing point as representative of each of the 26 IPM regions. Exhibit 29 shows all the pricing points as reported by Platt's "Gas Daily".

Exhibit 29: Platt's "Gas Daily" Pricing Points



Daily gas price data for the time period January 1, 1991 to October 30, 2002 were used in deriving the transportation adders. For summer, daily gas pricing data for May 1 – Sept 30 were used and for winter, daily gas pricing data for Oct 1 – April 30 were used. The transportation adders were calculated by subtracting the Henry Hub price from the derived regional prices. Data that were greater than two standard deviations of the mean were considered as indicating some short term phenomena or aberration and were not used in determining average basis differentials. A simple arithmetic average was taken for data points within two standard deviation of the mean. Exhibit 30 shows the overall methodology of generating basis differentials for use in IPM. Exhibit 8-9 earlier in the documentation report shows the resulting natural gas transportation adders that are used in EPA Base Case 2004, v.2.1.9.

Exhibit 30: Overall Flow Chart of Determining Basis Differentials



Appendix 8-3 Natural Gas Supply Curves for EPA Base Case 2004

The supply curves below specify annual price and volume relationships at the Henry Hub. For each listed step the price applies for all increments of supply greater than the value shown in the preceding step up to and including the supply level indicated in the current step. For example, in 2007 a price of $3.40 would secure natural gas supplies for the electric sector beyond the 5422 TBtu provided in the preceding step and up to a level of 5511 TBtu.

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2007	2.75	19411	23560	4149
2007	2.80	19314	23580	4266
2007	2.85	19220	23600	4380
2007	2.90	19128	23620	4492
2007	2.95	19038	23640	4602
2007	3.00	18950	23660	4710
2007	3.05	18863	23680	4817
2007	3.10	18778	23700	4922
2007	3.15	18695	23720	5025
2007	3.20	18614	23730	5116
2007	3.25	18534	23740	5206
2007	3.26	18514	23740	5226
2007	3.30	18457	23790	5333
2007	3.35	18378	23800	5422
2007	3.40	18299	23810	5511
2007	3.44	18243	23820	5577
2007	3.45	18224	23820	5596
2007	3.50	18157	23830	5673
2007	3.55	18090	23840	5750
2007	3.57	18066	23840	5774
2007	3.60	18021	23850	5829
2007	3.65	17952	23860	5908
2007	3.70	17884	23870	5986
2007	3.75	17818	23880	6062
2007	3.80	17753	23890	6137
2007	3.85	17689	23900	6211
2007	3.90	17626	23910	6284
2007	3.95	17564	23920	6356
2007	4.00	17503	23930	6427
2007	4.05	17443	23940	6497
2007	4.10	17384	23950	6566
2007	4.15	17326	23960	6634
2007	4.20	17269	23970	6701
2007	4.25	17212	23980	6768
2007	4.30	17156	23990	6834
2007	4.35	17101	24000	6899
2007	4.40	17047	24010	6963
2007	4.45	16994	24020	7026
2007	4.50	16941	24030	7089
2007	4.55	16889	24040	7151
2007	4.60	16838	24050	7212
2007	4.65	16788	24060	7272

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2007	4.70	16738	24070	7332
2007	4.75	16689	24080	7391
2007	4.80	16641	24090	7449
2007	4.85	16593	24100	7507
2007	4.90	16546	24110	7564
2007	4.95	16500	24120	7620
2007	5.00	16454	24130	7676
2007	5.05	16409	24140	7731
2007	5.10	16364	24150	7786
2007	5.15	16320	24160	7840
2007	5.20	16276	24170	7894
2007	5.25	16233	24180	7947
2007	5.30	16190	24190	8000
2007	5.35	16148	24200	8052
2007	5.40	16106	24210	8104
2007	5.41	16064	24220	8156
2010	2.75	19727	23780	4053
2010	2.80	19621	23890	4269
2010	2.85	19517	23990	4473
2010	2.90	19415	24090	4675
2010	2.95	19316	24190	4874
2010	3.00	19219	24290	5071
2010	3.05	19124	24390	5266
2010	3.10	19031	24490	5459
2010	3.15	18940	24590	5650
2010	3.16	18916	24620	5704
2010	3.20	18856	24850	5994
2010	3.25	18766	24970	6204
2010	3.29	18691	25070	6379
2010	3.30	18678	25080	6402
2010	3.35	18597	25130	6533
2010	3.40	18516	25180	6664
2010	3.45	18435	25230	6795
2010	3.46	18411	25240	6829
2010	3.50	18355	25300	6945
2010	3.55	18277	25390	7113
2010	3.60	18200	25480	7280
2010	3.65	18125	25570	7445
2010	3.70	18051	25660	7609
2010	3.75	17978	25740	7762
2010	3.80	17907	25820	7913
2010	3.85	17837	25900	8063
2010	3.90	17768	25980	8212
2010	3.95	17700	26060	8360
2010	4.00	17633	26140	8507
2010	4.05	17567	26220	8653
2010	4.10	17502	26300	8798
2010	4.15	17438	26380	8942
2010	4.20	17375	26460	9085
2010	4.25	17313	26540	9227

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2010	4.30	17252	26620	9368
2010	4.35	17192	26700	9508
2010	4.40	17133	26770	9637
2010	4.45	17075	26840	9765
2010	4.50	17018	26910	9892
2010	4.55	16962	26980	10018
2010	4.60	16906	27050	10144
2010	4.65	16851	27120	10269
2010	4.70	16797	27190	10393
2010	4.75	16744	27260	10516
2010	4.80	16691	27330	10639
2010	4.85	16639	27400	10761
2010	4.90	16588	27470	10882
2010	4.95	16538	27540	11002
2010	5.00	16488	27610	11122
2010	5.05	16439	27680	11241
2010	5.10	16390	27750	11360
2010	5.15	16342	27820	11478
2010	5.20	16295	27890	11595
2010	5.25	16248	27960	11712
2010	5.30	16202	28020	11818
2010	5.35	16156	28080	11924
2010	5.40	16111	28140	12029
2010	5.41	16066	28200	12134
2015	2.75	20148	24960	4812
2015	2.80	20060	25140	5080
2015	2.85	19974	25320	5346
2015	2.90	19890	25500	5610
2015	2.95	19808	25670	5862
2015	3.00	19727	25840	6113
2015	3.05	19648	26010	6362
2015	3.08	19599	26120	6521
2015	3.10	19569	26210	6641
2015	3.15	19489	26460	6971
2015	3.18	19442	26610	7168
2015	3.20	19413	26680	7267
2015	3.25	19343	26850	7507
2015	3.30	19273	27020	7747
2015	3.35	19203	27190	7987
2015	3.39	19144	27330	8186
2015	3.40	19134	27350	8216
2015	3.45	19069	27480	8411
2015	3.50	19004	27610	8606
2015	3.55	18939	27740	8801
2015	3.60	18874	27870	8996
2015	3.65	18809	28000	9191
2015	3.70	18744	28130	9386
2015	3.70	18741	28140	9399
2015	3.75	18683	28280	9597
2015	3.80	18623	28430	9807

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2015	3.85	18564	28580	10016
2015	3.90	18506	28730	10224
2015	3.95	18449	28880	10431
2015	4.00	18393	29020	10627
2015	4.05	18338	29160	10822
2015	4.10	18283	29300	11017
2015	4.15	18229	29440	11211
2015	4.20	18176	29580	11404
2015	4.25	18124	29720	11596
2015	4.30	18073	29860	11787
2015	4.35	18022	30000	11978
2015	4.40	17972	30140	12168
2015	4.45	17923	30280	12357
2015	4.50	17874	30410	12536
2015	4.55	17826	30540	12714
2015	4.60	17779	30670	12891
2015	4.65	17732	30800	13068
2015	4.70	17686	30930	13244
2015	4.75	17641	31060	13419
2015	4.80	17596	31190	13594
2015	4.85	17552	31320	13768
2015	4.90	17508	31450	13942
2015	4.95	17465	31580	14115
2015	5.00	17422	31710	14288
2015	5.05	17380	31840	14460
2015	5.10	17338	31960	14622
2015	5.15	17297	32080	14783
2015	5.20	17256	32200	14944
2015	5.25	17216	32320	15104
2015	5.30	17176	32440	15264
2015	5.35	17137	32560	15423
2015	5.40	17098	32680	15582
2020	2.75	20782	27560	6778
2020	2.80	20695	27720	7025
2020	2.85	20610	27870	7260
2020	2.90	20527	28020	7493
2020	2.95	20449	28160	7711
2020	2.95	20445	28170	7725
2020	3.00	20369	28320	7951
2020	3.05	20293	28470	8177
2020	3.10	20217	28620	8403
2020	3.15	20141	28770	8629
2020	3.20	20065	28920	8855
2020	3.25	19989	29070	9081
2020	3.29	19935	29180	9245
2020	3.30	19914	29230	9316
2020	3.35	19844	29400	9556
2020	3.40	19774	29570	9796
2020	3.45	19704	29740	10036
2020	3.49	19646	29880	10234

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2020	3.50	19636	29900	10264
2020	3.55	19577	30010	10433
2020	3.60	19518	30120	10602
2020	3.65	19459	30230	10771
2020	3.70	19400	30340	10940
2020	3.75	19341	30450	11109
2020	3.80	19282	30560	11278
2020	3.85	19223	30670	11447
2020	3.90	19164	30780	11616
2020	3.95	19105	30890	11785
2020	4.00	19046	31000	11954
2020	4.02	19024	31040	12016
2020	4.05	18990	31120	12130
2020	4.10	18936	31240	12304
2020	4.15	18883	31360	12477
2020	4.20	18830	31480	12650
2020	4.25	18778	31600	12822
2020	4.30	18727	31720	12993
2020	4.35	18677	31840	13163
2020	4.40	18627	31950	13323
2020	4.45	18578	32060	13482
2020	4.50	18530	32170	13640
2020	4.55	18482	32280	13798
2020	4.60	18435	32390	13955
2020	4.65	18389	32500	14111
2020	4.70	18343	32610	14267
2020	4.75	18298	32720	14422
2020	4.80	18253	32830	14577
2020	4.85	18209	32940	14731
2020	4.90	18165	33050	14885
2020	4.95	18122	33160	15038
2020	5.00	18080	33270	15190
2020	5.05	18038	33370	15332
2020	5.10	17997	33470	15473
2020	5.15	17956	33570	15614
2020	5.20	17916	33670	15754
2020	5.25	17876	33770	15894
2020	5.30	17837	33870	16033
2020	5.35	17798	33970	16172
2020	5.40	17759	34070	16311
2026	2.75	21087	27750	6663
2026	2.80	21004	27910	6906
2026	2.85	20923	28070	7147
2026	2.90	20844	28220	7376
2026	2.95	20767	28370	7603
2026	3.00	20691	28520	7829
2026	3.05	20617	28670	8053
2026	3.10	20544	28820	8276
2026	3.15	20473	28970	8497
2026	3.20	20403	29110	8707

YEAR	PRICE (1999 $/MMBtu)	Non Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)	Gas Supply to Electric Sector (TBtu)
2026	3.24	20346	29230	8884
2026	3.25	20336	29270	8934
2026	3.30	20278	29480	9202
2026	3.35	20220	29690	9470
2026	3.40	20162	29900	9738
2026	3.45	20104	30110	10006
2026	3.50	20046	30320	10274
2026	3.55	19988	30530	10542
2026	3.57	19965	30610	10645
2026	3.60	19925	30660	10735
2026	3.65	19859	30740	10881
2026	3.70	19793	30820	11027
2026	3.75	19727	30900	11173
2026	3.80	19661	30980	11319
2026	3.85	19595	31060	11465
2026	3.90	19529	31140	11611
2026	3.92	19507	31170	11663
2026	3.95	19476	31250	11774
2026	4.00	19429	31370	11941
2026	4.05	19382	31490	12108
2026	4.10	19335	31610	12275
2026	4.15	19288	31730	12442
2026	4.20	19241	31850	12609
2026	4.25	19194	31970	12776
2026	4.30	19147	32090	12943
2026	4.35	19100	32210	13110
2026	4.37	19081	32260	13179
2026	4.40	19053	32330	13277
2026	4.45	19006	32440	13434
2026	4.50	18960	32550	13590
2026	4.55	18914	32660	13746
2026	4.60	18869	32770	13901
2026	4.65	18825	32880	14055
2026	4.70	18781	32990	14209
2026	4.75	18738	33100	14362
2026	4.80	18695	33210	14515
2026	4.85	18653	33320	14667
2026	4.90	18611	33430	14819
2026	4.95	18570	33540	14970
2026	5.00	18529	33650	15121
2026	5.05	18489	33760	15271
2026	5.10	18449	33860	15411
2026	5.15	18410	33960	15550
2026	5.20	18371	34060	15689
2026	5.25	18333	34160	15827
2026	5.30	18295	34260	15965
2026	5.35	18258	34360	16102
2026	5.40	18221	34460	16239

Appendix 8-4. Biomass Supply Curves in EPA Base Case 2004

Available Biomass Fuel Supply (TBtu) in 2010 by Price (1999 $/MMBtu) and Biomass Supply Regions (based on National Energy Modeling System Regions)

Price	Biomass Fuel Supply (in TBTU) for 2010 by Biomass Supply Regions (Based on NEMS Regions)												
(1999$/MMBtu)	ECAR	ERCOT	MAAC	MAIN	MAPP	NY	NE	FL	STV	SPP	NWP	RA	CNV
0.75	20	2	21	2	4	25	12	13	21	2	6	1	3
1.00	20	2	26	6	4	25	12	13	21	2	6	1	14
1.25	42	7	26	6	9	25	13	23	45	9	12	5	14
1.50	42	15	26	13	10	25	13	23	55	17	17	5	25
1.75	59	15	27	21	14	25	13	23	82	48	24	11	31
2.00	59	24	27	21	14	25	15	23	82	48	24	11	31
2.25	61	35	33	33	17	26	15	26	111	88	52	23	66
2.75	600	93	33	342	589	26	15	26	111	88	52	83	66
3.00	600	93	88	342	589	80	75	63	558	447	240	83	91
4.00	811	147	129	400	770	140	146	63	840	704	541	137	145
5.00	811	147	129	400	770	140	146	79	840	704	541	137	145
Greater than $5	828	148	134	405	782	144	154	81	848	715	627	168	154