Appendix 8.1 Natural Gas Supply Curves for EPA Base Case 2000

A Technical Paper Prepared by ICF Consulting, Inc.

1. Introduction

In 1995, the Gas Systems Analysis Model (GSAM), developed by ICF Consulting under the sponsorship of the U.S. Department of Energy (DOE), was used to create the supply and demand curves and transportation adders for IPM. During the past five years GSAM has evolved, incorporating new data and modeling enhancements. Since 1995, updates on resource estimates, frontier resources, advances in E&P technology, costs, new environmental regulatory regimes, and federal lands access levers have been incorporated into GSAM. This version of GSAM has replaced virtually all the data, which were used in the now obsolete 1995 version of GSAM. In addition, this current version of GSAM incorporates characterizations of new supply technologies such as horizontal drilling that were not part of the 1995 version of GSAM. The impact of such improvements on the projected supply of natural gas is quite sizeable. In addition, resources from new emerging frontier basins have been incorporated in GSAM. New frontier basins may become important sources of supply in cases where the demand for gas is high (e.g., due to a large-scale switch to gas for electricity generation). Taking account of these new basins could impact the future growth in gas prices.

1.1 Brief Synopsis of GSAM

GSAM represents a flexible, sophisticated approach for modeling supply, demand, and transportation issues in the North American natural gas market. It has undergone a comprehensive, in-depth review by industry, government, and academic peers. (See Appendix 8.1.6 for further details.) It is reliable and efficient in analyzing the broad range of issues being addressed in this study and has been successfully used to evaluate various upstream and downstream issues in natural gas, including consideration of alternative technology scenarios, market conditions, and public policy initiatives on U.S. gas supplies and the strategic decisions made by oil and gas companies. Therefore, it is capable of providing a credible state-of-the-art characterization of the gas supply, transportation, and non-electricity demand for the EPA Base Case 2000.

On the upstream side of the market, GSAM has a gas resource base characterized by explicit geologic properties and operational characteristics for over 17,000 individual gas reservoirs and aggregate supplies represented in 28 supply regions. Since the characteristics of potential North American gas supplies are specified at this level of disaggregation, GSAM is free from restrictive assumptions such as regional average supply curves normally imposed by traditional gas market models. GSAM contains detailed information on individual gas reservoirs both in the U.S. and Canada. Each of the reservoirs has detailed information on the location of the reservoir, allowing the allocation of reservoirs into supply regions (Figure A8.1). In addition, GSAM contains resources located in frontier regions such as the Alaska North Slope, Mackenzie Delta, Newfoundland, Onshore Deep Gas, Ultra Deep Water, etc. A detailed discussion of frontier supply sources is available later in this document.

On the downstream side of the market, GSAM consists of 16 North American demand regions with over 80 transportation links connecting supply and demand regions. These links represent collections of pipelines serving the regions (or intermediate points) in question. The demand for natural gas is characterized by four sectors: residential, commercial, industrial, and electric power generation. Combined with multiple seasons and years, the result is a model that is rich in detail. The upstream and downstream sides of the market are brought into balance by an integrating linear program (LP) which seeks to maximize the sum of producer plus consumer surplus less transportation costs, resulting in equilibrium prices, quantities, and flows.

Key GSAM sub-modules interact with each other in a manner illustrated below to perform the aforementioned activities (Figure A8.2).

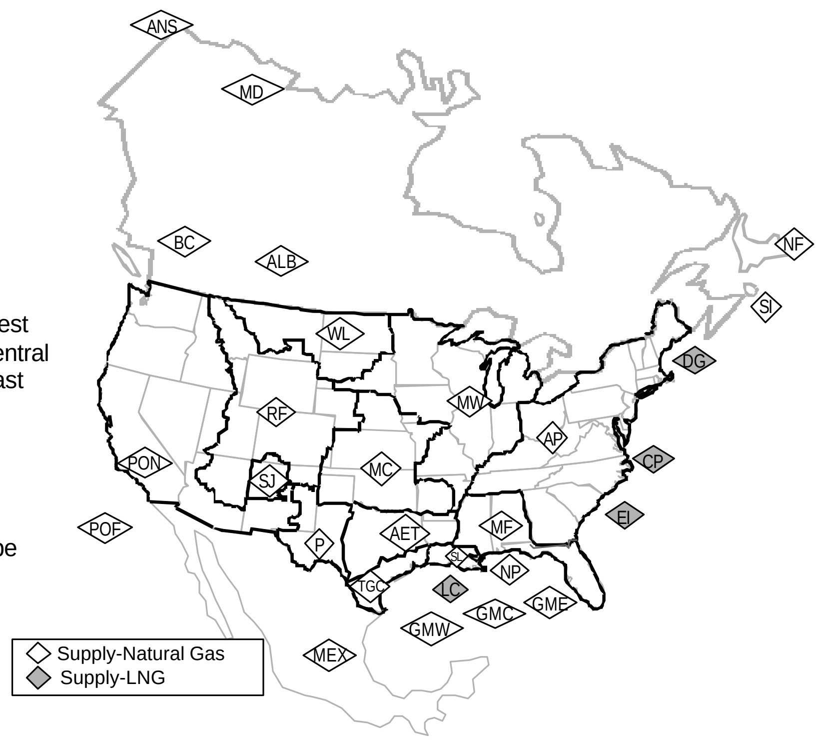
- ***Resource Module -*** transforms raw resource and reservoir data into fully characterized, reservoir-level databases. The module operates using several routines that evaluate available information and estimate missing data elements based on reasonable engineering and geologic default parameters.

- ***Reservoir Performance (RP) Module -*** estimates annual production volumes and costs associated with development of each known or potential producing natural gas reservoir characterized by the Resource Module.

Figure A8.1 Supply Regions of the Gas Systems Analysis Model (GSAM)

Regions in GSAM

POF:	Pacific Offshore
PON:	Pacific Onshore
SJ:	San Juan
RF:	Rockies Foreland
WI:	Williston
P:	Permian
MC:	Mid-Continent
AET:	Arkla-East Texas
TGC:	Texas Gulf Coast
GMW:	Gulf of Mexico-West
GMC:	Gulf of Mexico-Central
GME:	Gulf of Mexico-East
NP:	Norphlet
SL:	South Louisiana
MF:	MAFLA Onshore
MW:	Mid-West
AP:	Appalachia
ANS:	Alaska North Slope
MD:	MacKenzie Delta
ALB:	Alberta
BC:	British Columbia
SI:	Sable Island
DG:	Distrigas
CP:	Cove Point
EI:	Elba Island
LC:	Lake Charles
MEX:	Northern Mexico
NF:	Newfoundland



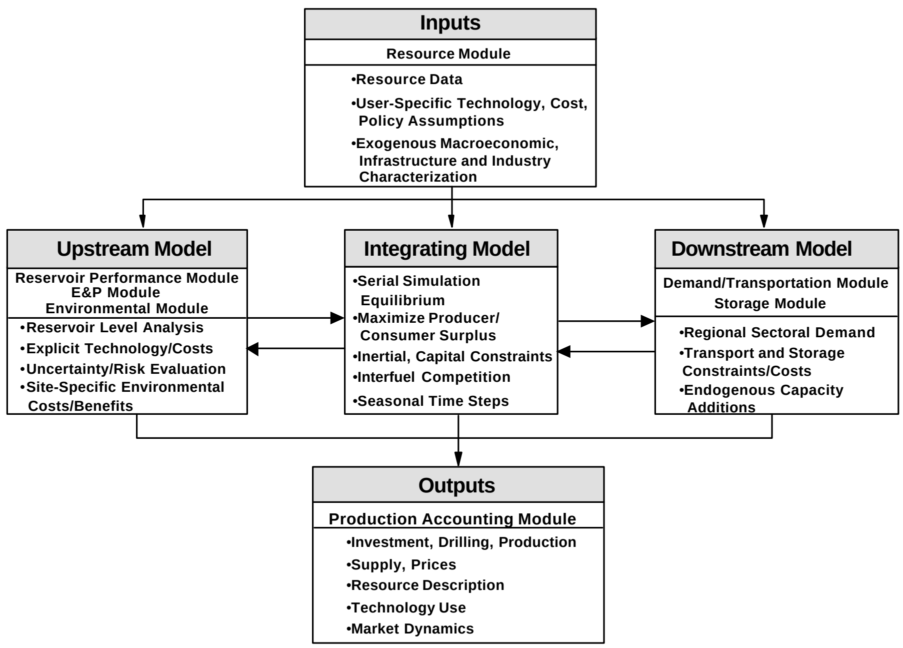
- ***Exploration and Production (E&P) Module -*** evaluates the exploration, development and production of the natural gas resource base over time as a function of contemporary market conditions and technology, economic, and policy assumptions. Gas prices can be exogenously input or calculated based on analysis using the Demand and Integrating Model.

- ***Demand and Integrating (D&I) Module -*** evaluates demand for gas by region, sector, and season as a function of gas prices, population growth, economic activity, interfuel competition, and other regional and national factors. It creates input files for operating the linear program to balance supply and demand across a nationwide transportation network linking supply and demand regions.

- ***Production Accounting (PA) Module -*** converts output from other modules to provide a full accounting of all exploration, drilling, completion, operations, and upstream activities. The output provides details on annual gas production, gross revenues, taxes, investments, operating costs, and operating profits.

The consistent evaluation of gas supply and demand under alternative economic, technology, regulatory, and policy conditions is the key benefit of GSAM, which is designed to be fully consistent with operator decision-making procedures. Its modular design as shown in Figure A8.2 provides flexibility in developing and completing various technology and policy assessments.

Figure A8.2 Major Components of the Gas Systems Analysis Model (GSAM)



2. Natural Gas Assumptions for EPA Base Case 2000

2.1 Natural Gas Reserves and Resources

A summary of various categories of natural gas resources for Lower-48 is provided in Table A8.1. GSAM accounts for natural gas from an Original Gas In Place (OGIP) point of view. OGIP is defined as the amount of natural gas that can be found in the pore spaces of various geologic formations. Various levels of technology application (termed as current technology and advanced technology) will develop different amounts of natural gas from these pore spaces and is termed as technically recoverable natural gas resources. Due to a variety of reasons (such as pore geometry, formation characteristics, pressure profile within reservoirs, etc.) 10-50% of natural gas volume may not be produced using the current state-of-the-art technologies. In GSAM, two technologies are applied to the resource base with a defined set of technology penetration parameters. This yields two sets of natural gas recoverable resources, one using current technology and the other using advanced technology, as shown in Table A8.1.

Table A8.1 Original Gas in Place (OGIP) and Various Categories of Natural Gas Resources in L-48

OGIP Estimates for Undiscovered Resource in GSAM (Tcf)	**1114.7**	
- Conventional	522.1	
- Coal and Shale	60.5	
- Tight	532.1	
L-48 Resources (Tcf)	**Current Technology**	**Advanced Technology**
Undiscovered Resource	**722.1**	**771.8**
- Conventional	322.0	341.6
- Coal and Shale	45.8	50.4
- Tight	354.4	379.8
Reserves Appreciation	**274.2**	**289.6**
Assessed Additional Resource	**996.3**	**1061.4**
Total Remaining Resources* (Proved and Assessed Additional)	**1153.3**	**1218.4**
*GSAM uses proved reserves of 157 Tcf		

As shown in Table A8.1, the total undiscovered (or new field discoveries) OGIP estimate in GSAM is 1114.7 Tcf divided into conventional, coal and shale, and tight resource categories. Assessed Additional Resource includes undiscovered as well as reserves appreciation or reserves growth and ranges from 996.3 to 1061.4 Tcf under current and advanced technology assumptions respectively. Total remaining resources in GSAM, that include proved, undiscovered and reserves appreciation ranges from 1153.3 to 1218.4 Tcf. The natural gas from the proven reserves category is based on the 14th update of NRG Associates (Significant Oil and Gas Fields in the United States Database, 1999) producing reservoir database. For comparison purposes, the 1995 United States Geological Survey (USGS) for onshore and the 2000 Minerals Management Service (MMS) for federal offshore assessments report Assessed Additional Resource of 1057 Tcf and NPC's 1999 report estimates total Assessed Additional Resource of 1309 Tcf for L-48 states. The natural gas resource estimates in GSAM are consistent with USGS for onshore U.S., and MMS for offshore U.S. Minor discrepancies arise since GSAM starts from OGIP numbers and then applies specific advanced technology levers to explore, develop and produce natural gas.

As mentioned earlier, undiscovered recoverable resource and reserves appreciation are calculated in GSAM utilizing two different sets of Exploration and Production (E&P) technology (current technology and advanced technology) parameters as shown in Table A8.2. The use of advanced drilling, completion, and exploration technologies can increase the recoverable reserves by over 49 Tcf (about 6.9% improvement) and it can also increase the reserves appreciation by 15.4 Tcf (about 5.6% improvement) as can be seen in Table A8.1. Total recoverable resource (undiscovered and reserves appreciation) is 996.3 Tcf using current technology and 1061.4 Tcf using advanced technology.

2.2 Characterization of E&P Technologies in GSAM

In order to assure consistent analytical results from GSAM and to appropriately address E&P technologies in a timely manner, several key aspects of data were obtained through a combination of research and consultations with DOE and industry before using in GSAM. In addition, key data elements were derived from the published literature, Energy Information Administration (EIA) publications, and proprietary data.

The majority of the E&P technology parameters was developed in consultation with the National Energy Technology Laboratory (NETL), United States Department of Energy (DOE). This exercise led to the development of E&P parameters (as shown in Table A8.2), the majority of which were used in a DOE/NETL study "Natural Gas Metrics 2000". This DOE study quantifies the projected impact of various elements of the DOE/NETL upstream natural gas R&D program on future gas supplies. The E&P technology parameters used in GSAM for the EPA Base Case 2000 represent a case defined as the full contribution of industry and the current portfolio of DOE/NETL natural gas R&D projects resulting in a plausible scenario for future natural gas supplies in the U.S.

The E&P technology assumptions in GSAM were developed to capture realistic technology advances that would play in the North American gas market. Current and possible advanced technology parameters were used to model the potential impact of expanded technology application on the gas market. Table A8.2 shows how the specific E&P technology factors considered were varied in the analysis.

As shown in Table A8.2, "skin factor," a dimensionless factor representing the restriction on gas flow in the near-wellbore domain, was reduced from current average values of between 7 and 10 under current drilling and completion practices, to 2 to 6 with advanced technology (different skin factors were specified in GSAM for different resource types analyzed). Completion and stimulation techniques were also assumed to improve for unconventional resources. Current practices achieve 150 to 300 foot effective fracture half-length (300 to 600 feet tip-to-tip), with improvements in fracturing technology, it increases to 400 to 600 foot. In line with the fracture half-length, the fracture conductivity, a measure of flow capacity of an induced fracture, was assumed to increase from 2 to 10 times. 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.

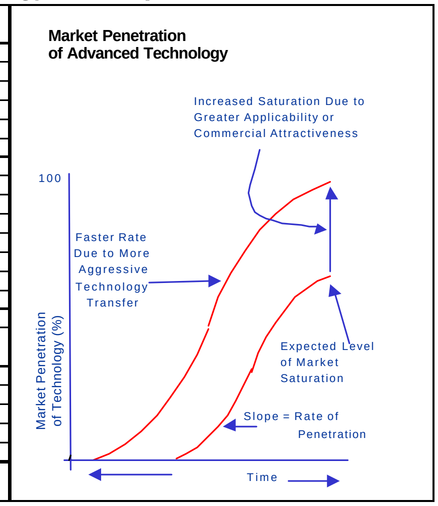
Cost and economic parameters were also varied in the analysis. Facilities, operating and variable operating and maintenance costs were assumed to be reduced by 20% and the compressor O&M cost by 1% with the advancement of technology. Drilling cost reduction for the current and advanced technologies were assumed to be the same at an annual rate of 1.5%.

In GSAM, 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 as shown in Table A8.2. 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 earlier and the ultimate saturation of these key advances. This resulted in typical "S" shaped technology penetration curves. (For additional background information on the cost and technology parameters in GSAM, see Appendix 8.1.1. For a focused examination of the nature of and basis for the E&P technology assumptions in GSAM, see Appendix 8.1.2.)

Table A8.2 Exploration and Production (E&P) Technology Assumptions for EPA Base Case 2000

Tecnology Parameters	Current Technology	Advanced Technology
Skin Factor: conventional gas	8	2
Skin Factor: tight gas	7	3
Skin Factor: coalbed methane	10	6
Fracture Half Length: tight gas (ft)	300	600
Fracture Half Length: coalbed methane gas (ft)	150	400
Fracture Conductivity*: tight gas (md-ft)	500	1000
Fracture Conductivity*: coalbed methane (md-ft)	50	500
Horizontal well lateral length: conventional gas (ft)	500	1000
Horizontal well lateral length: tight gas (ft)	1000	1500
Horizontal well cost factor w.r.t. vertical wells	1.3	1.17
Development dry hole rate (%)	20	10
Exploration dry hole rate: conventional gas (%)	75	65
Exploration dry hole rate: tight gas (%)	75	62.5
Exploration dry hole rate: coalbed methane (%)	65	60
Rig Retirement Rate (% of drilling footage capacity)	5	5
Cost and Economic Parameters		
Facilities Cost Reduction (%)	Varies by region	20% reduction
Operating Cost Reduction (%)	Varies by region	20% reduction
Variable O&M Cost ($/Mcf)	Varies by region	20% reduction
Compressor O&M Cost ($/Mcf)	0.05	0.0495
Annual Reduction in Drilling Cost (%)	1.5	1.5

*Fracture conductivity is a measure of flow capacity of an induced fracture. It is a product of fracture permeability and fracture width.



In addition to E&P technologies, policy and regulatory considerations were taken into account. The factors included environmental considerations affecting fuel use for E&P operations, access to exploration and development prospects, pipeline right-of-way, etc. Representation of these issues in GSAM was based on ICF Consulting's work for the Office of Fossil Energy (FE) at the DOE and the NPC.

2.3 Characterization of New Frontier Supplies

In addition to traditional sources of natural gas resources as described in section 2.1, GSAM also contains resources located in frontier regions. Information about these frontier resources are obtained from various publicly available sources, and supply curves are generated for each of the frontier resource category based on ICF Consulting's view of natural gas prices and supplies. Price/supply curve parameters for various regions and resource types are shown in Tables A8.3a and A8.3b.

- **Alaska North Slope (ANS):** The natural gas resource located in ANS is enormous, 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, the 6-8 Bcf/d of gas that is currently produced as part of the oil activities in ANS, 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, pipeline project proponents, and governments in both the US and Canada have in the past year stepped up efforts to bring to fruition the long-held dream of monetizing ANS gas. From a demand perspective, most forecasters indicate that the need for Alaskan gas in the Lower-48 will materialize this decade. ICF Consulting has completed various studies looking into the market potential of the ANS gas in the context of the overall North American energy markets. This has involved working with pipeline companies, E&P companies and the ANS producers' consortium on numerous occasions. For the EPA Base Case 2000, ICF Consulting has chosen to show Alaska North Slope gas being brought to the Lower-48 markets starting in the year 2007 and has assumed that gas will be transported through the Southern route as shown in Figure A8.3. We have not assumed any gas supplies from the Arctic National Wildlife Refuge (ANWR) in this study.

- **Mackenzie Delta:** 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 are in pools sufficiently large to justify construction of a new gas pipeline to take the gas south to Alberta. Research shows that the supply potential from Mackenzie delta may be as high as 2 Bcf/D. All of the Mackenzie delta discoveries are stranded at the present time, although several development proposals are under consideration (see Figure A8.3). 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 strength of Western Canadian gas prices due to deregulation of the industry. Until recently, most analyses and forecasts have tended to discount the need for Mackenzie Delta natural gas prior to 2020. The costs of exploration, development, production, and transportation to market were seen as too high to justify proceeding given the market and pricing outlook for the North American natural gas industry. For EPA Base Case 2000, ICF Consulting has assumed that Mackenzie Delta gas can be brought to the Lower-48 markets starting in the year 2008, one year later than the ANS due to our assumption of delays in obtaining necessary regulatory approvals in Canada. The Mackenzie Valley transportation corridor which takes gas directly from the delta to the Alberta system has been used. The Northern route and the Dempster lateral options were not selected as the choice of the transportation corridor from the ANS and Mackenzie Delta.

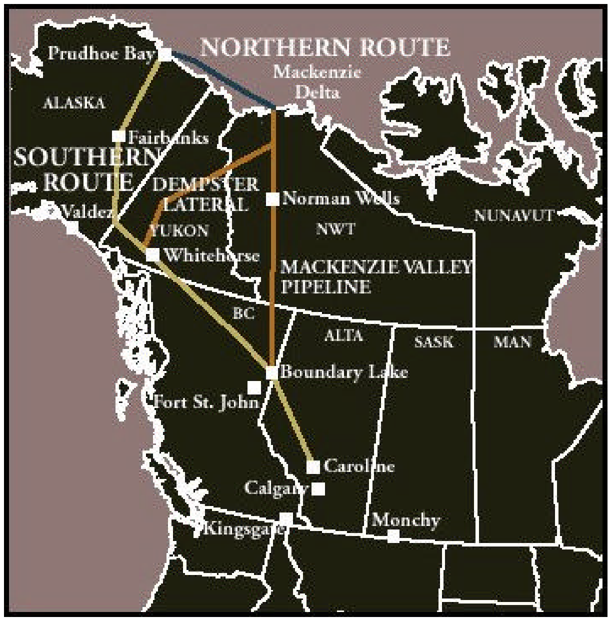
- **Ultra Deepwater Resource:** The ultra-deepwater (water depth greater than 5000 ft) Gulf of Mexico presents a unique opportunity to increase domestic reserves. Advancements in deepwater drilling technology over the past few years have enabled the industry to move out into water depths exceeding 7,500 feet, something unheard of only 5-6 years ago. As a result, the number and percentage of deepwater tracts leased in the Gulf of Mexico has grown exponentially during the past few years and there are now more than 1,800 existing oil and gas leases in water depths of 1,000 ft or greater in the Central and Western Gulf of Mexico planning areas. For the EPA Base Case 2000, ICF Consulting has assumed the availability of ultra- deepwater supplies from both the Central and Western Gulf of Mexico regions.

  The feasibility and challenges of bringing ultra-deepwater technologies to the marketplace were recently explored in the "Offshore Technology Roadmap for Ultra-Deepwater Gulf of Mexico" by DOE in cooperation with the MMS. This Roadmap recommends using the Natural Gas and Oil Technology Partnership as a mechanism for transferring advanced technologies developed either at the national labs or through laboratory and industry collaborations. This initiative comes at an important time as the nation faces increasing demands for energy. This partnership will promote the development, commercialization and implementation of new or existing technologies to lower the cost of ultra-deepwater exploration and production of oil and gas while maintaining safety of operations and protection of the marine environment.

  There are great transport challenges to be overcome for exploitation of the resources from ultra-deepwater sources. Until now, pipelines have been the sole means of transporting oil produced on fields in the Gulf of Mexico, and field operators in the Gulf are used to and experienced with using pipelines for transport. But an increasing number of fields in the ultra-deepwater sector of the Gulf of Mexico are remote from existing pipelines, driving the need to look at shuttle tankers as a transport solution.

  It is ICF Consulting's view that supplies from these ultra-deepwater sources could become available to the marketplace as early as 2005.

Figure A8.3 Gas Transportation Options from Alaska North Slope and Mackenzie Delta



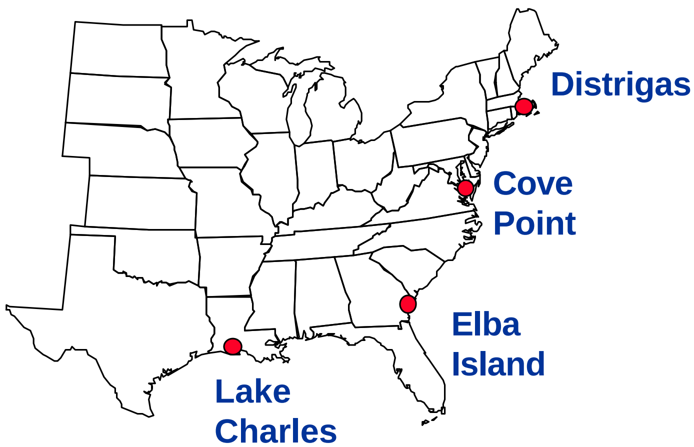
- **Onshore Deep Gas:** Onshore deep gas is defined as gas resources located in drilling depths of 15,000 ft or more and for the EPA Base Case 2000 we have assumed these resources to be located in GSAM's Texas Gulf Coast and South Louisiana regions. Deep gas resources located in these regions are the most promising sources for because of the abundance and high quality of the gas. South Louisiana is estimated to contain over 24 Tcf and Texas Gulf Coast region over 22 Tcf of deep gas resource. Other regions in the U.S. such as Rocky Foreland, and the Permian Basin contain large amounts of deep gas resources but the quality of gas is extremely poor. Deep gas resources located in these regions contain CO_2, and H_2S impurities and temperatures are generally very high which poses challenges for drilling and gas processing facilities.

  It is ICF Consulting's view that deep gas drilling can start to meet some of the increased demand as the industry looks to new and frontier sources of natural gas. The onshore deep gas supply curves have been generated based on our interpretations of the resource base and assumptions for the deliverability and recovery potential.

- **Liquefied Natural Gas (LNG):** 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 the high costs of transportation and liquefaction. Now, with price volatility and some evidence to show that average prices may be moving from $2.00 to over $2.50 per thousand cubic feet (Mcf), producers are cautiously looking into expanding the LNG market. According to DOE forecasts, LNG will not provide a major contribution to U.S. supply by 2020, but it is projected to make up a growing percentage of imports. During the recent spike in U.S. natural gas prices, the LNG market rushed to capitalize on the opportunity, planning re-activations, expansions, and new LNG facilities. There are currently four LNG terminals in the U.S. (Figure A8.4) and all four are modeled in GSAM. The terminals, Distrigas in Everett, Massachusetts and Lake

Charles in Louisiana are the only terminals in continuous operation. The other two are planning reactivation and expansion.

Figure A8.4 LNG Import Terminals in the U.S.



Elba Island terminal is located in Georgia and there are plans to reactivate this terminal in year 2003. Cove Point terminal is located in Maryland and there are plans to also reactivate this terminal in year 2003. In addition to these LNG projects, a number of new LNG proposals were envisioned in 2000 and 2001 , but with the recent downturn in LNG prices, it is doubtful that most of these projects will go ahead. It is clear from this recent rush that LNG terminals are able to reactivate quickly and expand inexpensively. EPA Base Case 2000 does assume these re-activations.

- **Landfill Gas:** Modern landfills are designed to provide an environmentally safe depository for refuse to biodegrade into a relatively stable state through biological processes. During this biodegradation, the waste progresses through an aerobic into an anaerobic decomposition phase producing landfill gas (LFG). LFG consists of approximately 43% carbon dioxide and 55% methane, with trace levels of other gases. The methane portion of the LFG has the energy equivalent of approximately 500 Btu per standard cubic foot of LFG. This is roughly half the energy content compared to natural gas. In this study, landfill gas has been assumed to be available in Appalachia, Mid-West and Pacific Northwest regions. The price threshold for landfill gas is over $3.50/Mcf (higher than the natural gas price projection for 2005-2020 from the EPA Base Case 2000) and therefore it does not contribute to supplies.

- **Northern Mexico:** Currently Mexico is a net importer of gas from the U.S. Most of the imported volumes into Mexico cross the border near El Paso in Texas and most of the natural gas volumes exported to the U.S. from Mexico cross the border near Reynosa, Texas. Mexico's promising non-associated natural gas basins – Burgos, Sabinas, and Parras – are all located in northeast Mexico close to the Texas border and are not currently producing (Figure A8.5). Gas production in Mexico is mainly associated with oil extraction in the southeast and the offshore zone. Mexico has approximately 63 trillion cubic feet of gas reserves and its reserve-to-production ratio implies a reliable supply for 36 years. Under-investment in exploration, field development, and gathering facilities has limited increases in natural gas production, despite the fact that in recent years more than 38 trillion cubic feet of non-associated gas reserves have been discovered near Burgos field in the northeast. Burgos' reserves represent 57.1 percent of total natural gas reserves but contribute only 17.3 percent to total natural gas production. Foreign energy companies are interested in the possibility that the Mexican government may allow private companies to produce and transport natural gas in the future, thus challenging the monopoly of the state energy company, Pemex. In this analysis, we have assumed that changes in Mexican policy will allow foreign investment in the development of the undiscovered as well as proven reserves and will make Mexico a net exporter to the U.S. by 2010.

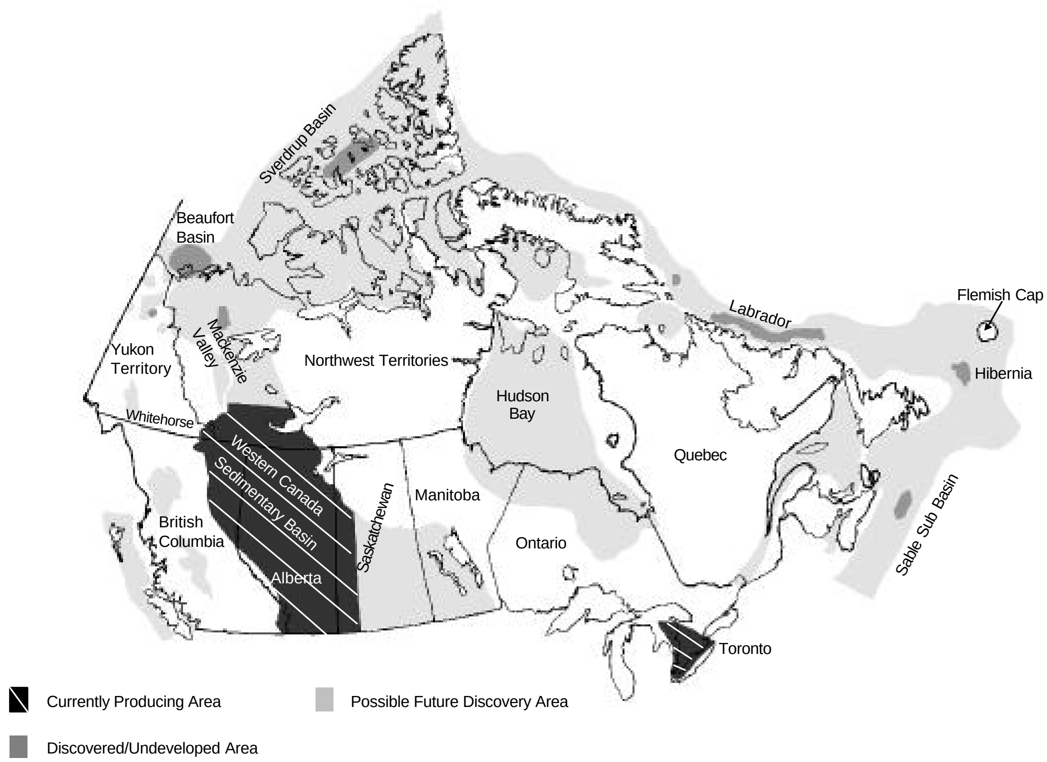
Figure A8.5 Primary Northern Mexico Non-Associated Natural Gas Basins

- **Offshore Newfoundland:** The natural gas resource base for the Newfoundland province of Canada is estimated to be around 62 Tcf, consisting of 8.2 Tcf of discovered proven and 53.7 Tcf of undiscovered resources. Of the discovered proven resources, 4.2 Tcf is on the Labrador Shelf and 4.0 Tcf is in the Jeanne d'Arc Basin on the Grand Banks. The proven reserves from these basins could increase as more drilling and data collection occurs. The major discoveries in the Jeanne d'Arc basin, Hibernia and Terra Nova, are oil with associated gas and the associated gas is used for re-injection into the reservoirs for pressure maintenance. This natural gas will be available for export only when no longer required for this purpose. Overall, Newfoundland's natural gas resources are valuable and potentially capable of supporting significant industrial initiatives. While the discovered resources are not yet large, the undiscovered potential holds significant promise. It is ICF Consulting's view that in order to justify the investment in the infrastructure for a natural gas transportation and distribution network on the Island of Newfoundland, it will be necessary for new industries that are major natural gas consumers to locate on the island. The export of natural gas from offshore Newfoundland into the North American market represents a potentially attractive option from a market perspective and is expected to occur by 2005.

- **Canadian Tight and Coalbed Resource:** Canadian tight gas resources, located in formations where permeabilities are generally lower than 0.1 md, are estimated to be abundant based on initial evaluations by the Energy Resources Conservation Board (ERCB) of Calgary, Canada. These estimates range anywhere from 175 Tcf to 1500 Tcf and are based on data sets containing geological information from between 40 and 400 wells. Considering the large geographic area over which this data must be applied, the large range of gas in place estimates is indicative of the early stage of reservoir characterization for tight gas resources in Western Canada. In ICF Consulting's view, based on current data available, the high cost of massive hydraulic fracturing needed to produce from the tight resources would make it uneconomic for the next twenty years. As new data become available (such as drilling or seismic data), this view may change.

  Western Canada's coalbed methane (CBM) resource has been estimated to be comparable in size to that of the province's conventional natural gas resource base. Although only limited drilling for CBM targets has occurred in the province to date, considerable interest in how development of this resource might proceed has been shown by the gas and coal industries, and the public and regulatory agencies. Consistent with Geological Survey of Canada estimates, EPA Base Case 2000 assumes 260 Tcf of CBM resource based in Alberta. In addition, 91 Tcf of coalbed methane resource in British Columbia has been assumed based on British Columbia's Ministry of Energy and Mines estimates. Western Canada coalbed supplies are assumed to be available after 2005 in this study. Various producing and potential natural gas basins in Canada are shown in Figure A8.6.

Figure A8.6 Current and Potential Gas Producing Basins in Canada



- **Sable Island:** The Canadian Association of Petroleum Producers (CAPP) estimates that Offshore Nova Scotia contains over 30 Tcf of recoverable natural gas resources. 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 from Sable Island only because of recent development activities in the area. Other regions of the area are in the early stages of leasing and data collection, and publicly available gas resource data are incomplete. According to Canadian Gas Potential Committee (CGPC), Sable Island is estimated to contain 3.7 Tcf of proven reserves, and 8.1 Tcf of undiscovered marketable natural gas. With advancements in technology, development of infrastructure to support additional facilities and rising gas demand in the neighboring area, more natural gas will be produced and transported from Sable. Commercial production from Sable started in December 1999.

Tables A8.3a and A8.3b show the lower and upper thresholds of gas prices (1999$ at Henry Hub) and the associated gas supplies for year 2005, 2010, 2015, and 2020. These tables also show the estimated starting years of these resources when they become available in GSAM at the threshold prices. Values in parenthesis indicate the upper supply and price levels for a specific year. (Further discussion of the Formation of Wellhead Prices in GSAM can be found in Appendix 8.1.3.)

Table A8.3a Supply Curves for Lower-48, Western Canadian Indigenous Imports and New Frontier Basins (Years 2005 and 2010)

Supply Source	Available to Start in Year	2005		2010	
		Lower [Upper] Supply (Bcf)	Lower [Upper] Henry Hub Price (1999$/Mcf)	Lower [Upper] Supply (Bcf)	Lower [Upper] Henry Hub Price (1999$/Mcf)
Lower 48 Reservoir Supplies	Active	16,558.9 [19,279.4]	1.50 [7.00]	17,394.7 [21,210.9]	1.50 [7.00]
Western Canadian Imports[1]	Active	2,364.7 [3,401.6]	1.50 [7.00]	1,733.5 [3,496.0]	1.50 [7.00]
Alaska North Slope	2007	NA	NA	112.9 [624.6]	2.30 [4.25]
MacKenzie Delta	2008	NA	NA	55.4 [730.8]	1.55 [4.75]
Sable Island	2000	292.0 [292.0]	1.50 [1.50]	292.0 [292.0]	1.50 [1.50]
LNG Distrigas	Active	96.1 [174.1]	1.50 [3.25]	96.1 [174.1]	1.50 [3.00]
LNG Elba Island	2003	34.8 [174.1]	2.80 [3.00]	34.8 [174.1]	2.80 [3.00]
LNG Cove Point	2003	34.8 [174.1]	2.80 [3.00]	34.8 [174.1]	2.80 [3.00]
LNG Lake Charles	Active	67.4 [108.4]	1.50 [3.25]	67.4 [108.4]	1.50 [3.00]
Uncharacterized Unconventional	2005	40.0 [200.0]	2.80 [3.00]	120.0 [1100.0]	2.50 [5.50]
Landfill Gas	2000	20.0 [100.0]	3.80 [4.00]	20.0 [100.0]	3.50 [3.70]
Ultra Deep Water	2005	83.3 [658.4]	2.55 [7.00]	164.5 [1151.5]	2.50 [5.50]
Onshore Deep Gas	2000	20.0 [2000.0]	2.30 [4.75]	100.0 [2000.0]	2.50 [3.80]
Newfoundland	2005	40.0 [300.0]	2.55 [3.75]	60.0 [500.0]	2.50 [4.00]
Canada Tight	2005	60.0 [1000.0]	2.65 [5.75]	60.0 [1000.0]	3.00 [4.00]
Northern Mexico	2010	NA	NA	100.0 [600.0]	2.50 [3.80]

[1]Western Canadian Imports include imports from indigenous western Canadian resources and do not include supplies from Alaska North Slope, MacKenzie Delta, and Sable Island, which are shown separately.

Table A8.3b Supply Curves for Lower-48, Western Canadian Indigenous Imports and New Frontier Basins (Years 2015, and 2020)

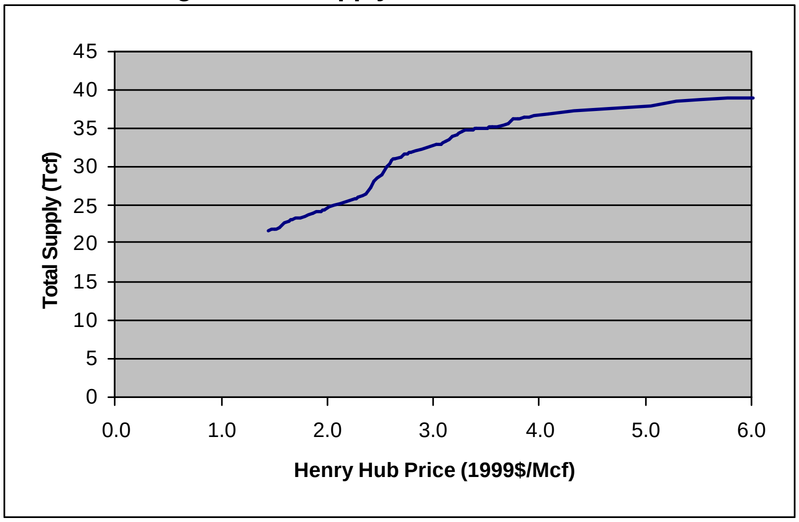
Supply Source	Available to Start in Year	2015		2020	
		Lower [Upper] Supply (Bcf)	Lower [Upper] Henry Hub Price (1999$/Mcf)	Lower [Upper] Supply (Bcf)	Lower [Upper] Henry Hub Price (1999$/Mcf)
Lower 48 Reservoir Supplies	Active	18,457.9 [24,690.7]	1.50 [7.00]	18,765.2 [26,112.1]	1.50 [7.00]
Western Canadian Imports[1]	Active	1,858.7 [3,507.5]	1.50 [7.00]	2377.6 [4120.9]	1.50 [7.00]
Alaska North Slope	2007	112.9 [624.6]	2.30 [4.25]	112.9 [624.6]	2.30 [4.25]
MacKenzie Delta	2008	55.4 [931.4]	2.05 [5.50]	55.4 [931.4]	1.80 [4.00]
Sable Island	2000	438.0 [438.0]	1.50 [1.50]	584.0 [584.0]	1.50 [1.50]
LNG Distrigas	Active	96.1 [174.1]	1.50 [3.25]	96.1 [174.1]	1.50 [3.25]
LNG Elba Island	2003	34.8 [174.1]	2.80 [3.00]	34.8 [174.1]	2.80 [3.00]
LNG Cove Point	2003	34.8 [174.1]	2.80 [3.00]	34.8 [174.1]	2.80 [3.00]
LNG Lake Charles	Active	67.4 [108.4]	1.50 [3.25]	67.4 [108.4]	1.50 [3.25]
Uncharacterized Unconventional	2005	120.0 [1100.0]	2.50 [4.25]	120.0 [1100.0]	2.50 [4.25]
Landfill Gas	2000	20.0 [100.0]	3.50 [3.70]	20.0 [100.0]	3.50 [3.70]
Ultra Deep Water	2005	170.0 [1545.5]	2.50 [5.25]	170.0 [1963.6]	2.50 [5.50]
Onshore Deep Gas	2000	100.0 [2000.0]	2.50 [3.40]	100.0 [2000.0]	2.50 [3.60]
Newfoundland	2005	60.0 [700.0]	2.50 [4.25]	60.0 [800.0]	2.50 [2.70]
Canada Tight	2005	60.0 [1000.0]	3.30 [5.50]	60.0 [1000.0]	3.30 [5.50]
Northern Mexico	2010	100.0 [600.0]	2.50 [3.80]	100.0 [600.0]	2.50 [3.80]

[1]Western Canadian Imports include imports from indigenous western Canadian resources and do not include supplies from Alaska North Slope, MacKenzie Delta, and Sable Island, which are shown separately.

2.4 Price/Supply Curve

Price/supply curves for the years 2005, 2010, 2015, and 2020 are generated using GSAM and populated in EPA Base Case 2000. The procedure for creating the price/supply curve is discussed in section 3 below. Figure A8.7 shows a sample of price/supply curve for the year 2015. The gas supply (available in U.S.) in this curve is the total gas production from the Lower 48 regions, Western Canadian imports from indigenous resources, LNG and the new frontier resources. Alaska North Slope and Mackenzie Delta supplies are included in new frontier resources. (Further background on the 2015 supply can be found in Appendix 8.1.4.)

Figure A8.7 Supply Curve for Year 2015



2.5 Natural Gas Demand Characterization

Regional demand is modeled in GSAM on a sectoral and seasonal basis, including the role gas storage can play in meeting gas demand. End-use demand is modeled for residential, commercial, industrial and electric utility sectors for each demand region. In any one year, the gas demand equals consumption in these sectors.

Electricity Demand: For the purpose of this study, input for electricity demand in GSAM was set consistent with electricity generation assumptions from the EPA Base Case 2000. First, the electricity generation, by IPM demand regions, is obtained and is then cross-walked to the GSAM demand region to produce GSAM electricity generation.

Residential Demand: The level of gas consumption in any year for the residential sector is a function of population growth (which affects household formation), GNP (through personal income and gross regional product), gas price, energy efficiency, residential heating and cooling values.

Commercial Demand: In the commercial sector, gas consumption is a function of GNP (through employment and floorstock), gas price, energy efficiency, commercial heating and cooling values.

Industrial Demand: Gas demand in the industrial sector is modeled in GSAM using two regression equations based on two types of fuels used in industrial burning units. For gas-only burning units (no fuel switching), the gas demand is a function of Gross Regional Product (GRP), energy intensity (which is defined as a ratio of industrial sector output to GRP), and the gas price. 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).

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2.6 Pipeline Transportation Network

In GSAM, the pipeline transportation network is modeled using over 80 bi-directional links. Some of the links represent pipeline level connections but others represent aggregate of pipelines connecting two regions/nodes. The links connect gas supply nodes with other supply nodes and ultimately with gas demand nodes. Figure A8.8 shows a sample of pipeline transmission links used in GSAM. Each link is characterized by maximum capacity, reservation charge, commodity charge, fuel usage and the first available year to expand. Table A8.4 shows pipeline specifications of the sample transmission links shown in Figure A8.8. Reservation Charge is a charge paid to reserve firm transportation capacity on a pipeline. It is basically a fixed monthly fee that a shipper pays to a pipeline in order to reserve space (capacity) on the system. It is paid whether or not gas is sold or transported through the pipeline. The commodity charge is a charge for sales or transportation service based on the amount of gas actually taken by the purchaser or shipper. Fuel usage represents gas consumed by compressors, etc. in transporting natural gas from a specified origin to a particular destination. It is specified in percent.

Designation of "unlimited" existing capacity in Table A8.4 for a specific link (such as Alberta Supply region to Western Canada demand region) means that the supply and demand regions are physically at the same geographic location and unlimited indigenous natural gas supply is available at the demand region. In addition, designation of "unlimited" future capacity in Table A8.4 for a majority of links indicate that pipeline links can expand to a model determined capacity depending upon the supply, demand and transportation dynamics regardless of an artificial cut-off. This expansion occurs at the existing fixed (i.e., the reservation charge) and variable (commodity charge) costs, assuming that expansions in GSAM occur as rolled-in rates.

Figure A8.8 A Sample of Pipeline Transmission Links in GSAM

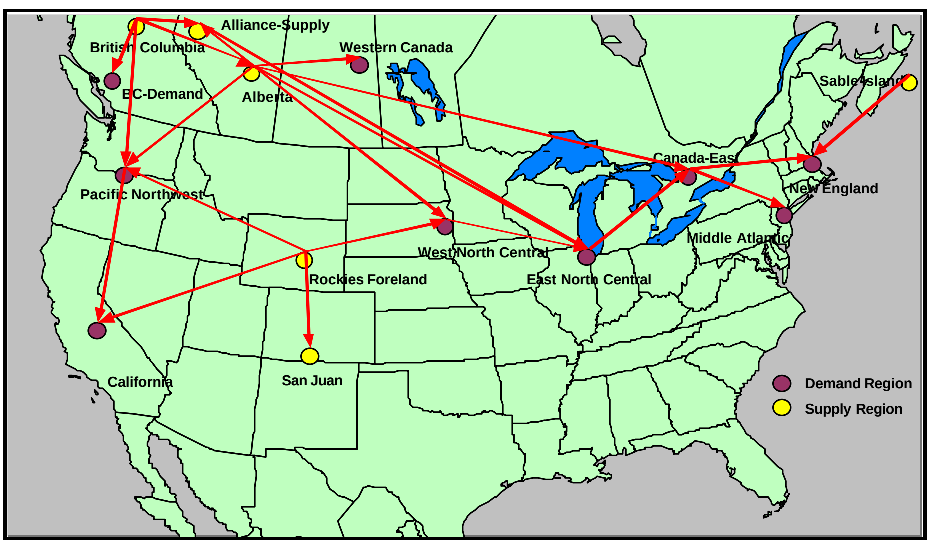


Table A8.4 Pipeline Specifications for Sample Transmission Links in Figure A8.8

Origin	Destination	Current Capacity (MMCF/D)	Future Capacity (MMCF/D)	Starting Year for Capacity Expansion	Reservation Charge $/Mcf per month	Commodity Charge $/Mcf	Fuel Usage (%)
Alberta	Canada-East	4053	Unlimited	2005	17.34	0.020	8.78
Alberta	East North Central	2447	Unlimited	2000	22.50	0.021	4.63
Alberta	Pacific Northwest	2426	Unlimited	2002	9.04	0.025	4.35
Alberta	West North Central	2008	Unlimited	1999	1.92	0.006	1.00
Alberta	Alliance-Supply	Unlimited	Unlimited	2000	2.25	0.005	1.00
Alberta	Western Canada	Unlimited	Unlimited	2000	5.97	0.022	2.00
Alliance-Supply	East North Central	0	4000	2000	23.00	0.012	3.40
British Columbia	Pacific Northwest	2750	Unlimited	2001	10.13	0.012	3.98
British Columbia	BC-Demand	1135	Unlimited	2001	2.95	0.024	3.00
British Columbia	Alberta	220	Unlimited	2000	6.67	0.012	3.98
British Columbia	Alliance-Supply	Unlimited	Unlimited	2000	2.25	0.005	1.00
Canada-East	Middle Atlantic	2072	Unlimited	2002	6.67	0.003	1.80
Canada-East	New England	63	Unlimited	2000	19.17	0.011	1.54
Sable Island	New England	0	Unlimited	2000	34.17	0.000	3.38
Rockies Foreland	California	730	Unlimited	2001	20.42	0.002	4.52
Rockies Foreland	Pacific Northwest	254	Unlimited	2002	8.60	0.001	1.51
Rockies Foreland	San Juan	961	Unlimited	2005	8.60	0.001	1.51
Rockies Foreland	West North Central	547	Unlimited	2003	7.60	0.036	3.48
Pacific Northwest	California	1831	Unlimited	2003	7.91	0.060	1.16
West North Central	East North Central	4406	6500	1999	4.55	0.054	3.38
East North Central	Canada-East	2030	5000	2000	7.50	0.024	3.20

GSAM endogenously expands the capacity of a transmission link if necessary demand conditions are met, economic requirements are fulfilled (with respect to the costs), and the year in which it needs to be expanded is after a predefined capacity expansion start-year. For some of the transmission links, the algorithm to set the capacity expansion in the near term is not based on economics and is actually based on company announcements. These links are forced to a set of pre-specified capacities. Table A8.5 lists the forced capacities of the transmission links in GSAM.

Table A8.5 Pre-specified Forced Capacity for a Sample of Transmission Links

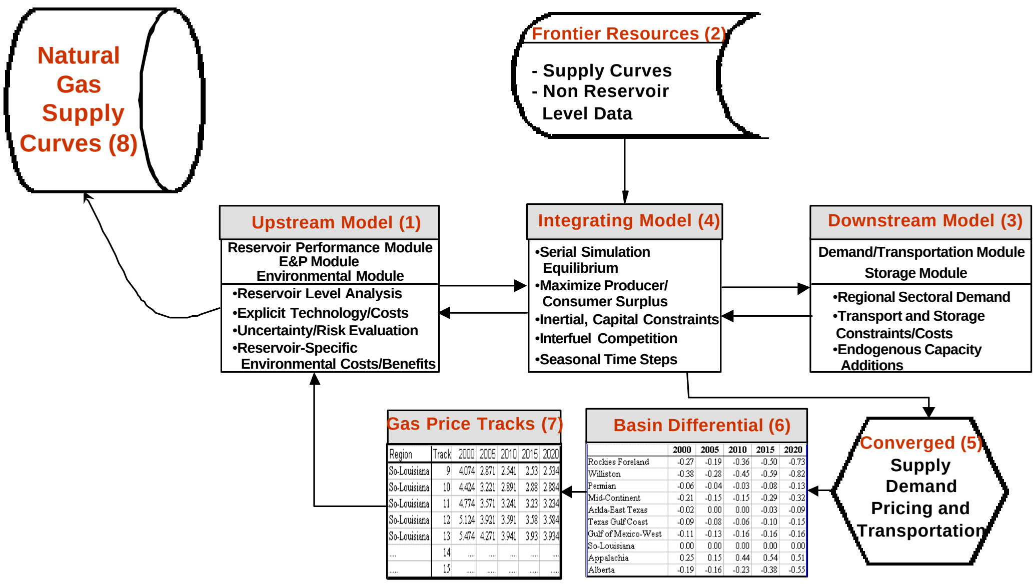
Origin	Destination	Year	Forced Capacity (MMCF/D)
Alberta	West North Central	1999	700
West North Central	East North Central	1999	700
Distrigas	New England	2001	175
Alliance-Supply	East North Central	2000	1500
Sable Island	New England	2000	400
Canada-East	New England	2000	178
Norphlet	MAFLA Onshore	2001	1000
Pacific North West	California	2003	200
Texas Gulf Coast	So-Lousiana	2002	400
East North Central	Middle Atlantic	2002	500
Alberta	East North Central	2000	500

3. Steps for Creating Supply , Non-Electricity Demand Curves and Transportation Adders

3.1 Supply Curves

The procedure for creating natural gas supply curves is shown schematically in Figure A8.9 (Follow steps 1 through 8 in Figure A8.9). The procedure starts with basin differentials (step 6) obtained from the converged upstream and downstream runs (upstream E&P Model, Integrating Model, and downstream Model of GSAM). The basin differential quantifies the relative attractiveness of different producing basins in the U.S. and Canada. Once the basin differentials are established, several different gas price tracks, from $1.50/Mcf to $7.00/Mcf (at $0.35/Mcf increments), are created for each producing basin keeping the basin differential the same. One upstream E&P Module run is then performed for each of the gas price tracks to create the supply curves.

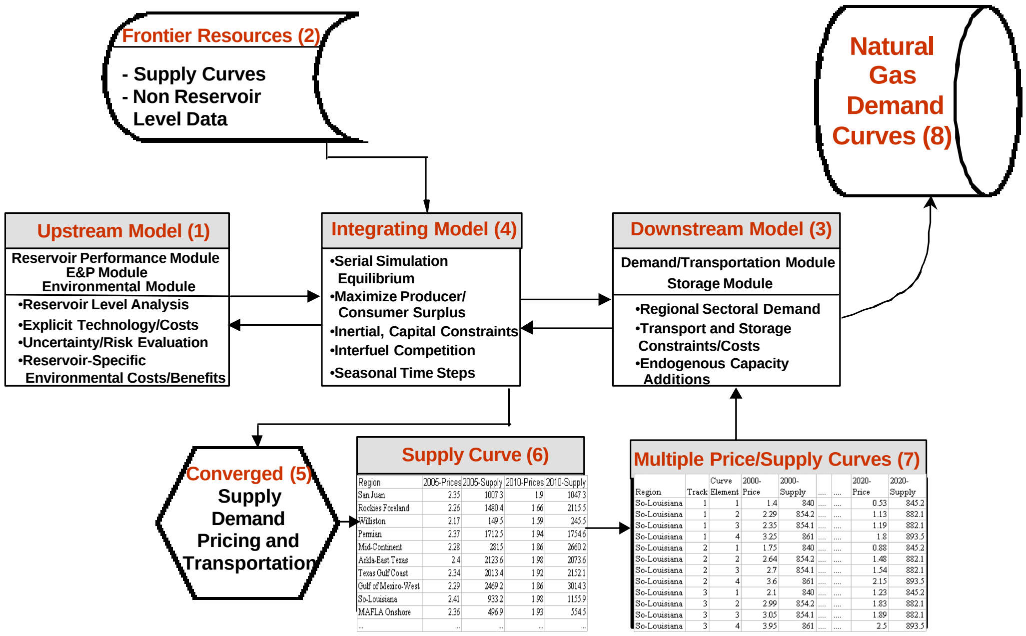
Figure A8.9 Procedure for Creating Natural Gas Supply Curves



3.2 Non-Electricity Demand Curves

Figure A8.10 shows the schematic of the procedure for creating non-electricity demand curves (Follow steps 1 through 8 in Figure A8.10). Alternative price/supply curves are generated for every region by changing the wellhead prices but keeping the supply volumes the same. These supply points are generated at $0.35/Mcf increments. Once the price/supply curves are generated, the downstream model of GSAM is run and a new set of equilibrium conditions for supply, demand, pricing, and transportation is generated. Each equilibrium run provides one data point for generating the non-electricity demand levels for the EPA Base Case 2000.

Figure A8.10 Procedure for Creating Non-Electricity Demand Curves



3.3 Transportation Differentials

Transportation differentials are produced using GSAM's supply/demand/transportation balance and ICF Consulting's view. These differentials are generated based on the wholesale natural gas prices by year and by GSAM region obtained from the converged integrated run. First, the transportation differentials with respect to Henry Hub are calculated by year and by GSAM region. GSAM regions are then mapped into IPM regions and transportation differentials are reported according to IPM regions. Table A8.6 shows the transportation differentials used in the EPA Base Case 2000 relative to Henry Hub. (See Appendix 8.1.5 for further discussion of GSAM's transportation algorithms.)

Table A8.6 Transportation Differentials for EPA Base Case 2000

	ECAO	MANO	MECS	MACE	MACW	MACS	MAPP	LILC	NENG	VACA	TVA	UPNY	NYC
2005	0.17	0.09	0.15	0.34	0.19	0.34	-0.08	0.46	0.51	0.19	0.12	0.26	0.36
2010	0.20	0.08	0.18	0.46	0.22	0.46	-0.12	0.58	0.61	0.34	0.12	0.38	0.48
2015	0.25	0.08	0.23	0.67	0.27	0.67	-0.16	0.79	0.80	0.57	0.13	0.59	0.69
2020	0.28	0.08	0.26	0.67	0.30	0.67	-0.21	0.79	0.80	0.57	0.13	0.59	0.69

	DSNY	WUMS	ENTG	SOU	SPPN	SPPS	FRCC	ERCT	RMPA	NWPE	AZNM	PNW	CALI
2005	0.36	0.10	0.01	0.10	-0.11	-0.08	0.61	-0.05	-0.24	-0.19	0.04	0.04	0.34
2010	0.48	0.10	0.01	0.10	-0.11	-0.08	0.63	-0.05	-0.32	-0.27	0.03	-0.02	0.32
2015	0.69	0.10	0.01	0.11	-0.11	-0.08	0.66	-0.05	-0.35	-0.30	0.02	-0.11	0.25
2020	0.69	0.10	0.01	0.11	-0.11	-0.08	0.69	-0.05	-0.37	-0.32	-0.01	-0.15	0.23

3.4 Seasonal Gas Price Adders

The seasonal gas adders in the EPA Base Case 2000 are used to distinguish between summer and winter delivered gas prices. Seasonal gas adders vary by region in IPM. In general, seasonal gas adders for winter are higher than in summer. In winter, due to lower temperatures, there is higher demand for gas by the residential sector for space heating. This results in higher gas pipeline utilization and therefore in higher delivered gas prices. Table A8.7 shows the season gas adders used in the EPA Base Case 2000. The values were derived from natural gas market data.

Table A8.7 Seasonal Gas Price Adders in EPA Base Case 2000 [1999¢/MMBtu]

Winter	ECAO	MANO	MECS	MACE	MACW	MACS	MAPP	LILC	NENG	VACA	TVA	UPNY	NYC
2005	8.45	8.45	8.45	32.21	32.21	0	8.45	32.21	37.04	0	0	32.21	32.21
2010	8.45	8.45	8.45	32.21	32.21	0	8.45	32.21	37.04	0	0	32.21	32.21
2015	8.45	8.45	8.45	32.21	32.21	0	8.45	32.21	37.04	0	0	32.21	32.21
2020	8.45	8.45	8.45	32.21	32.21	0	8.45	32.21	37.04	0	0	32.21	32.21

Summer	ECAO	MANO	MECS	MACE	MACW	MACS	MAPP	LILC	NENG	VACA	TVA	UPNY	NYC
2005	-12.3	-12.3	-12.3	-45.6	-45.6	0	-12.3	-45.6	-40.8	0	0	-45.6	-45.6
2010	-12.3	-12.3	-12.3	-45.6	-45.6	0	-12.3	-45.6	-40.8	0	0	-45.6	-45.6
2015	-12.3	-12.3	-12.3	-45.6	-45.6	0	-12.3	-45.6	-40.8	0	0	-45.6	-45.6
2020	-12.3	-12.3	-12.3	-45.6	-45.6	0	-12.3	-45.6	-40.8	0	0	-45.6	-45.6

Winter	DSNY	WUMS	ENTG	SOU	SPPN	SPPS	FRCC	ERCT	RMPA	NWPE	AZNM	PNW	CALI
2005	32.21	8.45	-4.3	0	-4.3	0	0	-4.3	25.43	13.45	25.43	25.43	16.83
2010	32.21	8.45	-4.3	0	-4.3	0	0	-4.3	25.43	13.45	25.43	25.43	16.83
2015	32.21	8.45	-4.3	0	-4.3	0	0	-4.3	25.43	13.45	25.43	25.43	16.83
2020	32.21	8.45	-4.3	0	-4.3	0	0	-4.3	25.43	13.45	25.43	25.43	16.83

Summer	DSNY	WUMS	ENTG	SOU	SPPN	SPPS	FRCC	ERCT	RMPA	NWPE	AZNM	PNW	CALI
2005	-45.6	-12.3	2.98	0	2.98	0	0	2.98	-23.8	-7.3	-23.8	-23.8	-14.3
2010	-45.6	-12.3	2.98	0	2.98	0	0	2.98	-23.8	-7.3	-23.8	-23.8	-14.3
2015	-45.6	-12.3	2.98	0	2.98	0	0	2.98	-23.8	-7.3	-23.8	-23.8	-14.3
2020	-45.6	-12.3	2.98	0	2.98	0	0	2.98	-23.8	-7.3	-23.8	-23.8	-14.3

4. Natural Gas Supply Results

Table A8.8 presents a summary of natural gas supply results broken down by resource types (conventional, tight and coal and shale) and frontier regions. The “Total Gas Produced” is the aggregate gas supply needed to meet the combined demand of the electricity sector (represented in the EPA Base Case 2000) along with the demand from all other sectors — residential, commercial, and industrial. The “Wellhead Price” is the market clearing price at Henry Hub at which this aggregate level of natural gas supply would be produced. Under the EPA Base Case 2000 the electricity sector’s gas supply needs are 5965.7 TBtu in 2005, 7376.0 TBtu in 2010, 8827.3 TBtu in 2015, and 10175.2 TBtu in 2020.

Table A8.8 Natural Gas Supply Results

	2005	2010	2015	2020
Wellhead Price (1999US$/MMBtu)	**2.55**	**2.45**	**2.45**	**2.45**
Total Gas Produced (Tbtu)	**23249.7**	**25586.0**	**27744.2**	**30032.3**
Gas Produced from Lower 48 (Tbtu)	**18594.4**	**20174.6**	**22590.9**	**23440.1**
- Conventional	14716.7	15272.0	16745.8	16980.9
- Coal and Shale	1001.2	1040.2	1225.2	1191.3
- Tight	2876.5	3862.4	4620.0	5267.9
Gas Produced from New Frontier Basins (Tbtu)	**4655.3**	**5411.4**	**5153.3**	**6592.2**
- Alaska North Slope (ANS)	0.0	581.6	581.6	581.6
- MacKenzie Delta (MD)	0.0	722.6	722.6	920.9
- Western Canadian Imports (without ANS and MD)	3635.5	2513.5	2197.1	3367.1
- Sable Island	300.8	300.8	451.1	601.5
- Uncharacterized Unconventional	0.0	247.8	204.6	171.4
- Landfill Gas	0.0	0.0	0.0	0.0
- Ultra Deep Water	223.8	339.7	330.4	330.3
- Onshore Deep Gas	219.4	206.5	170.5	142.8
- Newfoundland	107.4	123.9	156.3	165.3
- Canada Tight	0.0	0.0	0.0	0.0
- Northern Mexico	0.0	206.5	170.5	142.8
- LNG Distrigas	99.0	99.0	99.0	99.0
- LNG Elba Island	0.0	0.0	0.0	0.0
- LNG Cove Point	0.0	0.0	0.0	0.0
- LNG Lake Charles	69.4	69.4	69.4	69.4

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Additional Documentation on the Gas Systems Analysis Model (GSAM)

The following supplemental appendices provide additional information about key features of GSAM.

Appendix 8.1.1 Assumptions for Cost and Technology Parameters in GSAM

In GSAM, production type curves are explicitly designed to evaluate the performance and economic impacts of various technologies on future gas supplies. This is accomplished by direct variation of parameters related to the exploration, drilling, completion, reservoir characterization, and production characteristics for individual reservoirs. These production type curves are developed to characterize the explicit impact on well performance and costs of alternative technology scenarios due to R&D activities.

Individual investments and operating processes are uniquely captured in GSAM to determine their cost to operators and are therefore reflected in the supply curves for IPM. These are:

- Based on published sources at the level of resource type and region
- Adjusted/verified by vendor quotes for known costs
- Based on regional, rate/depth specific values, where appropriate
- Based on commercial costs, not R&D level costs
- Technology-specific
- Can be adjusted for market conditions.

The key well-productivity parameters for the current and advanced technologies used in GSAM and their sources include:

- Skin Factors (Society of Petroleum Engineers, DOE/NETL)
- Fracture Lengths (Society of Petroleum Engineers, DOE/NETL, ICF)
- Horizontal Wells (Society of Petroleum Engineers, DOE/NETL, ICF)
- Technology Penetration Rates (DOE/NETL, ICF)
- Dry Hole Rates (Trade press, Society of Petroleum Engineers, ICF)
- Drilling Capacity (API, ICF)

The costs and investment parameters used by GSAM and their sources include:

- Geological and Geophysical (G&G) Costs (API survey, Bureau of Census)
- Lease Bonus data (published in trade press)
- Drilling and Completion (Joint Association Survey published by API)
- Equipment (EIA)
- Stimulation (vendors)
- Operating costs (EIA)

DOE/NETL program managers have reviewed the majority of the cost and technology parameters used in GSAM for a study that formed the basis for the current EPA Base Case 2000. These parameters are entered in GSAM based on the available literature and the final judgement of ICF Consulting and program managers at DOE/NETL. Assumed rates of market penetration of improved technologies were developed based on ICF Consulting's view on the pace of advancement of the E&P technologies in consultation with DOE/NETL. As certain advanced technologies (such as completion, cementing, horizontal well technology etc.) become more standardized and used by operators their impact would result in lowering the cost of supplies. The resulting decline in the drilling and operating costs are based on historical trends, conversations with EIA, and ICF

Consulting's assumptions.

The model does not address capital availability. However, in a 10.5 trillion dollar U.S. economy, the money required for natural gas drilling and development is minimal. There may and will be individual companies, however, with no access to capital but we don't foresee this to impact the long-term supply availability in the U.S. because economic exploration and development projects would attract investors.

The overriding principle of GSAM's 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 GSAM are based on a specified hurdle rate to be met. In other words it is inherently assumed in GSAM's modeling logic that enough capital will be available for projects that can meet (or exceed) the minimum cost of capital constraint of 10% and therefore, there are no capital constraints in the model. Instead of keeping track of dollars available for use in advanced technology applications as would be the case in a capital or budget constraint, the model uses a physical constraint such as drilling rig capacity constraint. This is realistic since an attractive drilling prospect could generate sufficient funding and thereby avoid the need for a budget limit but would not be able to bypass the physical constraint on the actual number of existing plus potential available drilling rigs. This approach is appropriate for modeling the behavior of a reservoir operator who would act in a rational economic manner and whose activities are profit-motivated.

By lowering finding, development, and operating costs, reducing risk, and increasing productivity of individual reservoirs, the advancement of E&P technologies directly impacts the future supplies of natural gas. These are reflected in higher volumes of gas supply available at various price levels. GSAM's supply modules provide summary economics of the undiscovered and discovered resource using the current and advanced technologies. These are then utilized to create the supply curves for IPM at different price tracks. An overall low or high gas price resulting from IPM can be attributed to many factors including assumptions in IPM about demand growth, inter-fuel competition, other market conditions in addition to the cost/supply curves for natural gas.

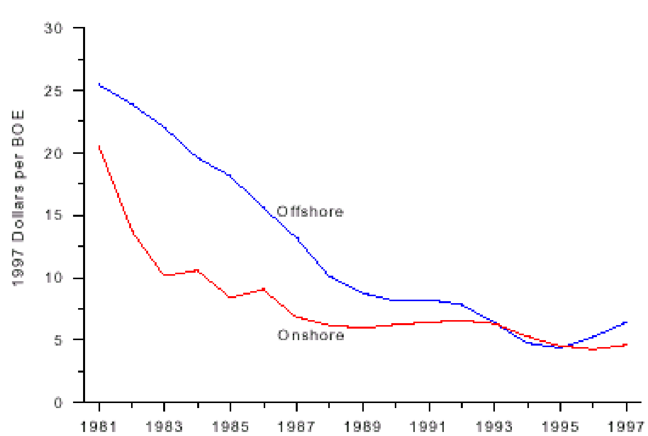
Appendix 8.1.2 Additional Comments on E&P Technology Assumptions in GSAM

Improvements in E&P technologies have historically been an extremely important factor in allowing the North American natural gas industry to maintain adequate levels of natural gas supplies. There have been several major developments in the industry over the last decade that have led to dramatic reductions in the cost of finding and developing natural gas resources. The most important changes are in the development and deployment of new E&P technologies used to explore, drill and eventually produce the new resources. These include 3-D and 4-D seismic technologies, horizontal drilling, and new drilling, completion and stimulation technologies.

ICF Consulting believes the technology improvements in the future will continue to improve the ability of producers to find new resources, increase the amount of gas recovered from each reservoir, and reduce the cost of finding and producing gas. In these ways the advancement in E&P technologies will help in keeping gas supplies adequate and gas prices moderate. For example, improvements in exploration technology allow producers to better discern geologically promising formations where natural gas is likely to be found. As a result, fewer exploratory wells will need to be drilled in order to find new gas fields. Similarly, improved well drilling and completion technologies improve recovery efficiency and production rates. For example, new drilling fluids like aerated muds, reduce near well-bore formation damage and improve gas flow rates. Use of horizontal wells improves well productivity in suitable candidate reservoirs.

Historical technological improvements have impacted productivity, recovery and costs of natural gas E&P operations. As can be seen from Figure 8.1.2.1, a dramatic decline in the finding costs of major energy producing companies has occurred in last 15 years. For offshore regions, the finding costs have declined from $15 per barrel of oil equivalent (BOE) to $4 per BOE (1997 dollars) in the 10 years from 1986 to 1996. A slight surge in offshore finding cost appeared after 1995 primarily due to deepwater exploitation and application of advanced technologies in high payoff, high cost areas. In deepwater areas, in addition to an exploration well, up to 4 delineation wells are drilled before a "discovery" is declared which increases the finding costs. Despite the increase, offshore finding costs are "competitive" relative to onshore because of potential upside. Huge resources relative to onshore justify higher finding costs.

Figure 8.1.2.1: EIA's Estimate of U.S. Onshore and Offshore Finding Costs for Major Energy Companies (1981-1997)



The decline in finding costs have occurred because of the tremendous strides in innovation and technology that have refined virtually all aspects of the industry. The three key factors for the cost decline are: cost management, reduction in project development time, and improved well performance. Outsourcing of nonstrategic services have also played a role in overall cost reductions. In outsourcing certain services are shared by multiple companies, which helps in reducing the net cost to a company. The overall effect of outsourcing is to convert fixed costs to variable costs (i.e., pay only when you use). For example, inspection of operational equipment by qualified contractor personnel and equipment on a part-time basis allows these resources to be used for multiple projects and/or companies. As costs are shared across a larger volume of service, the costs associated with any one project decline. Outsourcing is expected to play a critical role in the future in the E&P industry as it has in the information technology industry, where multi-billion dollar outsourcing contracts are common.

In addition to finding costs, operating and lease equipment costs are also expected to decline due to technological progress. GSAM's assumption of a drilling cost decline of 1.5% per year is a reasonable assumption based on historical trends.

Organizations like the Petroleum Technology Transfer Council (PTTC) are in the forefront of disseminating exploration and production technology to small, independent U.S. producers, which helps accelerate the application of profitable technologies to the industry. In addition, the National Energy Technology Laboratory (NETL) at the Department of Energy is active in conducting E&P research and development activities through partnerships with majors and independent producers, cooperative research and development agreements (CRADAs) and grants. A listing of the E&P R&D activities conducted at DOE/NETL is provided in Table 8.1.2.1, the majority of which have been embedded in GSAM's advanced technology assumptions for the EPA Base Case 2000. The GSAM E&P technology parameters impacted by the R&D activities are also shown in Table 8.1.2.1.

Gas Technology Institute (GTI), International Centre for Gas Technology Information (ICGTI), Canada's recently established Technology Centre for Natural Gas (TCNG), and Potential Gas Committee (PGC) of the Colorado School of Mines are also involved in various aspects of natural gas technology research, which will be instrumental in meeting natural gas demand cost effectively and efficiently. It is, however, important to mention that not all the innovation will be endogenous to the industry. Learning-by-doing and exogenous advances such as improvement in computer technologies have revolutionized the data management and processing required for the interpretation software of 3-D seismic. Such technology will continue to impact other natural gas technologies.

ICF Consulting believes that, as with any revolutionary product or technology development, initially, there will be inertia among users in trying the new technology. This was evident with 3-D seismic technology where experience was required to convince companies' management that the added cost of 3-D surveys was worth the benefit. Firms often looked to less expensive 2-D surveys first to determine the need to spend exploration dollars on 3-D seismic. However, the cost of 3-D surveys has declined due to improvements in technology and increased competition among seismic service companies, and the benefits to exploration are becoming better appreciated. As a consequence, 3-D seismic is now considered to be a primary tool for exploration activities. ICF Consulting believes similar inertia and cost concerns will exist with other advanced technologies initially, but over time there will be universal acceptance of these technologies as confidence and technical merits are realized.

Table 8.1.2.1: Listing of Advanced E&P Technologies Implemented in GSAM

DOE/NETL E&P Research Projects		Upstream Parameters Impacted from R&D Activities												
Title: DOE/NETL E&P Research Projects	E&P Research Partner	Drilling Cost	Completion and Stimulation Cost	Facilities Cost	Operating Cost	Reservoir Productivity	Storage Deliverability	Reserves Lifetime	Exploration Drilling Success Rates	Development Drilling Success Rates	Conventional Gas Recovery Factor	Unconventional Gas Recovery Factor	Drilling Capacity	Reserve Growth
I. ADVANCED DIAGNOSTICS AND IMAGING														
1 Resources and Reserves														
Geological research	USGS					X			X	X				
Western basins research	USGS					X		X	X	X				
Basin-centered gas study	USGS					X		X	X	X				
Geotechnology for low-perm gas reservoirs	Sandia National Lab					X			X					
Geopressured analysis	INEEL					X			X	X				
Deep gas study	USGS					X		X						
2 Natural Fracture Detection														
Geomechanics method for fracture detection	ARI					X			X	X				
Next generation fracture detection	ARI					X			X	X				
3-D seismic S-waves fracture detection	University of Texas, Austin	X				X			X	X				
Fracture Detection in Appalachia	SUNY, Buffalo					X			X	X				
Multi-attribute seismic for res. Char.	Stanford University	X				X				X				
3-D Fracture Modeling	Indiana University					X			X					
Natural fracture detection	Geospectrum	X				X			X	X				
Natural fracture diagnostics validation	LB													
3 Low Permeability Production Enhancement														
Optimization of infill drilling methods	New Mexico Tech., Socorro					X		X						
[illegible] Production enhancement	[illegible]	X				X		X	X	X			X	
[illegible] demonstration	University of Wyoming							X	X	X				
II. RESERVOIR LIFE EXTENSION														
4 Stripper Wells														
Stripper well diagnostics	[illegible] ARI							X						
Produced water remediation	[illegible]				X			X						
Stripper well consortium	Penn State							X						
Advanced well control system	[illegible]							X						
5 Reserves Growth														
Reserve growth in the Appalachian basin	West Virginia Univ. Research Council					X		X						X
Cross-well seismic for infill drilling	LB									X				X
Reserve growth by play	University of Texas, Austin							X		X				X
Reserve growth in the Northern Gulf of Mexico	Bureau of Economic Geology (BEG)					X		X						X
III. DRILLING, COMPLETION, and STIMULATION														
6 Drilling														
High power, slimhole drilling system	Maurer Engineering	X											X	
High pressure coiled tubing system	Maurer Engineering	X				X							X	
High temperature LWD tool	Sperry Sun	X						X					X	
High temperature MWD tool	Maurer Engineering	X						X					X	
Mud activated downhole hammer	Novatek International	X				X					X	X	X	
Ultra deepwater production system	Conoco			X		X								
Hydraulic pulse drilling	Tempress Tech.	X											X	
Suction pulse seismic while drilling	Tempress Tech.	X												
New TSP diamond cutters	Tech. International	X											X	
Laser Drilling	GRI	X												
Advanced drilling components	Penn State	X											X	
Composite drill pipe	ACPT	X							X	X				
7 Completion and Stimulation														
Field testing/optimization of CO2/sand fracturing	PCS		X								X	X		
Ultra-lightweight Cement	CSI		X		X									
Fracturing fluid characterization facility	University of Oklahoma		X								X	X		
Perforation dynamics	[illegible]		X			X					X	X		
Real-time monitoring of stimulation	[illegible]		X					X						
Downhole fluid analyzer	APS				X	X								
[illegible] best practices	Texas ETS										X	X		
8 Underbalanced Drilling														
Underbalanced drilling products	Maurer Engineering	X	X					X			X	X	X	
IV. Gas Storage														
9 Conventional Storage														
CRADA	NFESCO, Equitrans, CGT - HET						X							
Storage deliverability enhancement stimulation	[illegible]						X							
Mt. Simon research study	University of Illinois													
Direct energy meter	Southwest Research Institute			X	X									
Storage well remediation	ARI [illegible]	X	X				X							
VI. Gas Processing														
10 Gas Upgrading														
Inorganic ... gas separation membranes	SNL													
Microbially-enhanced redox solution	Texas A&M				X									
Membrane process research	MTR				X									
Liquid absorbent for removing nitrogen	[illegible]				X									
Hydrates ... recovery research	[illegible]				X									
Novel composite membrane research	IMS				X									

In this analysis, ICF Consulting has assumed that E&P technology improvements will continue at a pace and level consistent with historic trends and the use of advanced E&P technologies will be critical in supplying natural gas at affordable rates. It is also assumed that with time these advanced technologies become widely adopted by both majors and independents. A discussion of the three areas of technology improvements emphasized in this study: horizontal wells, drilling, completion and stimulation technologies and exploration technology follow.

Horizontal Well Technology

The use of horizontal and deviated wells in the U.S. has increased significantly over the last decade. During the five-year period 1990-1994, the percentage of horizontal wells drilled onshore increased by a factor of 18, while the percentage drilled offshore increased by a factor of 7. In addition, nearly half of the wells in the prolific Gulf of Mexico are directionally drilled, the techniques of which are akin to horizontal drilling techniques. Many of the promising supply sources of the future will be likely candidates for horizontal and deviated drilling technology.

Horizontal wells are most advantageous when reservoir conditions call for greater contact between the well-bore and the reservoir formation such as in a reservoir with a thin pay zone. These wells have important resource development implications because recovery rates and extraction rates are higher than possible with conventional vertical wells. Higher recovery and extraction rates mean that some development projects become economic with horizontal technology that were not viable with conventional vertical well technology. Horizontal wells on average cost 10-30 percent more than an average vertical well on a per foot basis, but produce anywhere from 2 to 5 times more than a vertical well. In addition use of horizontal wells can potentially reduce the number of wells needed to be drilled, thereby lowering overall drilling costs, operating costs, and facility and surface equipment costs. Even though horizontal wells have been drilled with horizontal segments up to 8,000 ft long, an average, horizontal segment of 500 ft for conventional resources and 1000 ft for tight gas resources (where either a horizontal well or hydraulic fracturing is almost always needed for economic exploitation of the resource) is a reasonable average for all the horizontal wells drilled currently. As technology progresses and more and more independents learn the use and applicability of horizontal wells, a horizontal segment of 1000 ft for conventional resources and 1500 ft for tight gas resources by year 2020 is reasonable. The application of horizontal drilling technology is currently seen on a limited scale in fractured conventional reservoirs, fractured source rocks, stratigraphic traps, heterogeneous reservoirs, and coalbeds (to produce their methane content), and older fields (to boost their recovery factors). This is due to the concerns of small operators for appropriate economic return and difficulty in identifying candidate reservoirs for horizontal well applicability. State organizations, such as the Kansas Geological Survey (KGS) have developed cost-effective techniques to allow independent producers to evaluate horizontal drilling candidates in mature fields. Similar efforts are being undertaken by technology transfer associations and, therefore, there is no reason to suppose that there would not be widespread applicability in the future as assumed in the EPA Base Case 2000.

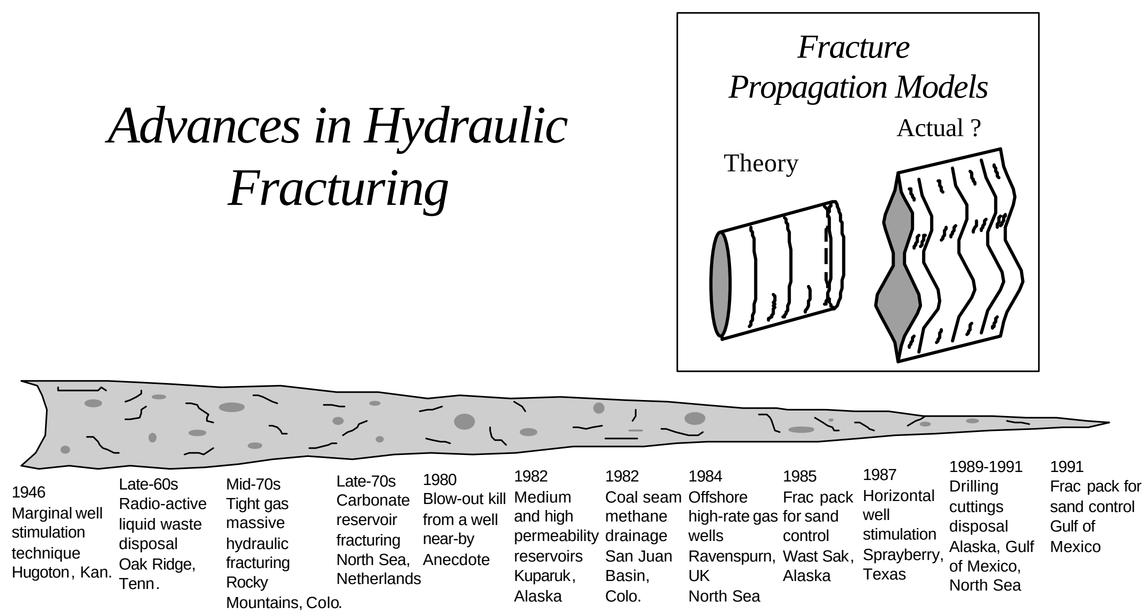
Drilling, Completion, and Stimulation Technologies

The industry continues to make improvements in drilling, completion, and stimulation technologies. The use of improved drilling fluids (such as aerated muds), underbalanced drilling practices, and non-damaging fracturing fluids is expected to reduce the resistance to flow near the well-bore (skin factor) by a factor of four (average conventional skin factor will be reduced from an average of 8 in current technology to 2 for advanced technology), if applied universally. Skin factor for tight gas and coalbed methane is also expected to decline due to continuing R&D activities in the areas of hydraulic fracturing, acidizing, well testing, coalbed methane multi-mechanistic fluid flow research and reservoir modeling. In addition, advances in remote sensing, satellite imagery and high resolution aeromagnetics, multi-azimuth 3-D seismic, and modeling of basement tectonics and basin evolution have helped and will continue to help in finding sweet spots in existing fields.

One of the key stimulation technology, hydraulic fracturing, has come a long way since its inception in the Hugoton gas field in year 1946 (Figure 8.1.2.2). Since its inception, hydraulic fracturing has developed from a simple, low-volume, low-rate fracture stimulation method to a highly engineered, complex procedure. In the 1980s research in this area extended the use of this technology to medium-to-high permeability reservoirs and thereby greatly increasing its applicability.

A more detailed understanding of hydraulic fracturing technology is critical because future gas supplies are expected to increasingly come from unconventional formations that typically require stimulation (hydraulic fracturing) in order to produce gas at economical rates. Ongoing research in the area of fracture propagation modeling (such as 2D and 3D analytical models, and sophisticated multi-dimensional numerical models) is attempting to understand the size and shape of the fractures created in the formation. The Strategic Center for Natural Gas (SCNG) at the DOE has realized the importance of this key technology and has been involved in researching the physical phenomena and costing issues associated with hydraulic fracturing. Since almost all tight gas and fractured formations are hydraulically fractured and are expected to supply a significant percentage of the total gas supplies by year 2020, such research will bring much needed design and operating improvements for efficient exploitation of these resource types.

Figure 8.1.2.2: Hydraulic Fracturing Technology



Published estimates indicate that the average finding cost for oil and natural gas activities have declined by over 50 percent from 1982 to 1995. This has resulted from a variety of R&D activities in the areas of seismic technology, drilling technology, extended reach drilling, well testing, and fracture modeling. ICF Consulting believes that such cost declines will continue in the future because of research and development activities conducted at DOE laboratories, industry and associations. Even though the R&D investment of major E&P

companies has declined, research and development activities will continue to be conducted in large part by DOE and state governments (such as NYSERDA) through cost-share R&D initiatives, and by research organizations that pool resources from multiple major E&P companies and overseas.

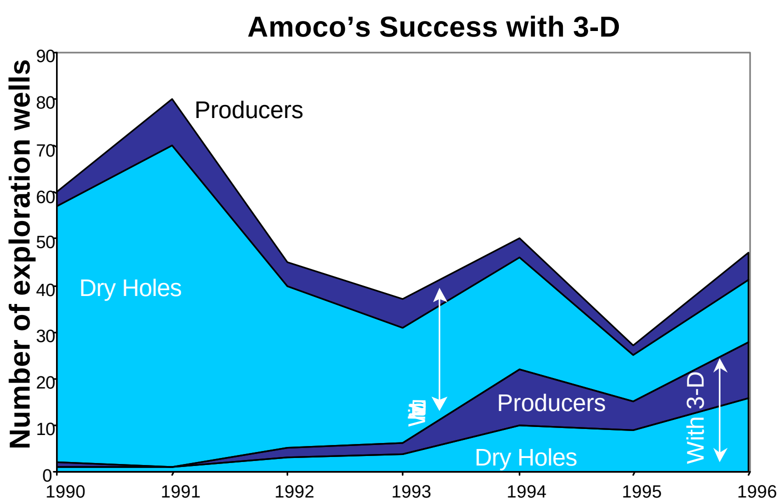
Exploration Technology

Exploration activities have become more efficient over the last five years primarily driven by the development and deployment of 3-D and 4-D seismic and data management and processing technologies, which improve the ability to identify promising formations. More recently, 4-D seismic technologies aid in investigating seismic data over time, which help in identifying fluid migration paths, channels in formations and untapped reservoir zones. These technologies provide geologists with a refined view of the rock formations that have a high probability of containing hydrocarbons. Initially, 3-D seismic was applicable only in open water, or on dry, easily accessible land. With the advancement of sophisticated telemetry and technology, 3-D seismic surveys can be conducted affordably and responsibly in deepwater and environmentally sensitive areas such as swamps, marshes etc.

As a result of advancement in the seismic technologies, companies have reported substantial reductions in dry hole rates for exploration drilling (Figure 8.1.2.3). Between 1990 and 1995, Amoco Production Company applied 3-D seismic technology in a number of its exploration activities. Amoco achieved an average exploration success rate of 13 percent for wells drilled without using 3-D seismic technology and 48 percent for wells drilled using 3-D technology.

Based on publicly available data, ICF Consulting assumes that the dry hole rates will decrease by 10 percent for conventional resources during the forecast period due to advances in the seismic technology. Tight gas and coalbed methane resources are continuous type formations where better success rates with application of these technologies are also assumed.

Figure 8.1.2.3: Effectiveness of 3-D Seismic Technology in Reducing Dry Holes



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Appendix 8.1.3 Formation of Wellhead Prices in GSAM

Wellhead prices can be viewed either as a netback price to producers based on market perspectives or more appropriately for long-term equilibrium modeling such as in GSAM as a cost-base. In this approach the wellhead price includes finding and development costs, operating and processing costs, taxes, royalties and a reasonable rate of return on capital.

There are three primary drivers for the establishment of long-term wellhead prices. The first driver is the size of resources, their availability and the feasibility of tapping as evident from the large-scale discoveries such as the advent of deepwater Gulf of Mexico that has impacted long-term prices in the U.S. The second driver is technology/finding improvements that impact the efficiency of exploration and development operations. An example is the improvement in the Geological and Geophysical (G&G) technology that has helped in locating sweet spots in natural gas fields, improving in-fill drilling potential, and thereby resulting in lower overall prices. Thirdly, demand over time for gas is another key driver for long-term natural gas prices. Demand for natural gas is dependent on the growth in natural gas fired electricity generation, inter-fuel competition, and consumers preference which is driven more by income elasticity than price elasticity as society gets wealthier.

All the three drivers are captured in GSAM for price/supply curve generation. Representative North American wellhead prices have traditionally been reported at Henry Hub. Henry Hub is a pipeline interchange hub in Louisiana Gulf Coast near Erath, LA, where eight interstate and three intrastate pipelines interconnect. This is the primary point of exchange for the New York Mercantile Exchange (NYMEX) active natural gas futures contracts and is considered as a proxy for U.S. natural gas prices. Natural gas from the Gulf of Mexico moves through the Henry Hub onto long-haul interstate pipelines serving the Midwest and the Northeast markets.

Appendix 8.1.4 Examination of 2015 Supply Curve

As can be seen from Figure A8-7 in Appendix 8.1, the supply curves are flatter around $2.40/Mcf to $2.80/Mcf range and prices do not increase considerably with higher supplies. Table 8.1.4.1 shows the supply components in generating the price/supply curve for $2.40/Mcf - $2.80/Mcf price range for year 2015 and provides a fairly good idea of the relative contribution of these sources. The increase in supplies from the frontier areas is primarily due to the fact that frontier resources are assumed to be ready for exploitation in sizable quantities at this point of time. It is our view that research conducted in understanding the potential from these frontier sources, assumptions about drilling costs decline in real terms, and advancement of the state-of-the-art E&P technologies in characterizing new resources would pave way for development of these resources within the next twenty years. It is our view that sizeable quantities of the frontier resources will come online at sustained prices of $2.40/Mcf and higher.

The six key supply categories showing substantial increases in supply in the price range $2.40/Mcf to $2.80/Mcf in year 2015 are:

1) Mackenzie Delta

The price/supply curve for Mackenzie Delta indicates that a total of 277 Bcf of natural gas will be available for the markets at price levels of $2.40/Mcf. We have assumed that at relatively sustained prices of $2.40/Mcf and higher, a ramp up in production from existing fields, drilling of more wells, and a push for bringing new satellite and major fields on production would happen, resulting in higher overall supplies from the Delta. ICF Consulting assumes that at $2.80/Mcf, 894.1 Bcf of natural gas will be available for the markets. Natural gas undiscovered resource located in the Delta is sufficient to support such production levels at these sustained prices.

2) Uncharacterized Unconventional Resource

Geologic and engineering research is being conducted at DOE/NETL and other research laboratories in characterizing the magnitude of unconventional resources, such as coalbed methane gas, which are currently uncharacterized. The oil and gas industry geologists, engineers, non-profit associations and policy makers believe that a vast majority of these unconventional resources exist but reservoir characterization and detailed technical evaluation is needed to evaluate the exact potential from these uncharacterized resources. We have assumed these untapped uncharacterized unconventional resources in the U.S. and Canada exist in U.S. Rockies region and Western Canada Sedimentary Basin (WCSB). In addition, research is needed and planned by companies for designing effective production technologies from these resources. It is ICF Consulting's view that these uncharacterized unconventional resources will provide important gas supplies in the future at wellhead prices higher than $2.50/Mcf. At $2.50/Mcf this resource category brings 120 Bcf to the market and increases to 600 Bcf once the wellhead price reaches a sustained level of $2.80/Mcf. This contributes to the flattening of the curve as seen in Figure A8-7 of Appendix 8.1.

3) Ultra Deepwater

The deepwater royalty relief of 1995 was designed to encourage exploration and development in the deeper waters of the Gulf of Mexico. This measure coupled with sizable quantities of natural gas in ultra deepwater (water depth greater than 5000 ft) has stimulated the interest among oil and gas companies in developing these resources. It is ICF Consulting view that at sustained prices of $2.50/Mcf and higher, sizable quantities of ultra deepwater supplies can be brought to the marketplace. We have assumed that at $2.50

a total of 170 BCF is available from this source and as prices increase to $2.80 over 1 Tcf can be available. This contributes to the flattening of the curve as seen in Figure A8-7 of Appendix 8.1.

4) Onshore Deep Gas

Onshore deep gas is a promising source of new supply. A new library of seismic data and a package of analytical tools developed by Gas Technology Institute (GTI) and service companies such as Schlumberger provide insights into the relatively unexplored deep gas opportunities in South Louisiana region. This knowledge can be utilized in characterizing resource potential from Texas Gulf Coast region, another key contributor of onshore deep gas supplies. We have assumed these supply regions to be the primary source of good quality deep gas in year 2015 as shown in Table 8.1.4.1 at gas prices of $2.50/Mcf and higher. The contribution of onshore deep gas increases from 100 Bcf at $2.50/Mcf to 600 Bcf at $2.80/Mcf in year 2015 which contributes to the flattening of the curve as see in Figure A8-7 of the Appendix 8.1.

5) Newfoundland

In offshore Newfoundland, some of the key fields such as Hibernia, Terra Nova, White Rose in the Grand Banks area contain sizeable quantities of oil and gas resources. Labrador shelf fields such as North Bjarni, Gudrid and Bjarni, are non-associated gas fields and contain over 4 tcf of undiscovered natural gas. Currently the area produces oil and all associated gas production is re-injected in the reservoir for pressure maintenance purposes. However, the government of Newfoundland and Labrador is conducting multiple studies to understand issues related to natural gas monetization. The government is in the process of re-designing the royalty structure and fiscal regime in the area targeted for natural gas production.

Oil and gas production in offshore Newfoundland and Labrador is both distant from markets and located in difficult to develop areas, with extreme operating conditions. Most of the gas and natural gas liquids production in the area would be associated with oil production that would require investments in infrastructure facilities. ICF Consulting completed a study "A Market Analysis of Natural Gas Resources Offshore Newfoundland" for the Newfoundland Ocean Industries Association (NOIA) in year 2000, that gives a general idea on the availability of natural gas from this area. The ultimate market for the offshore gas is the North American gas grid where the producers of the offshore Newfoundland resource will be price takers. As price takers, the wellhead price will be a netback from the prevailing market clearing price in eastern Canada (or the U.S.), that is, a market price less the cost of transportation, processing, royalties and taxes. Based on our interpretations of publicly available studies and reports, we believe that at sustained price levels of $2.50/Mcf Newfoundland can supply at least 60 Bcf of natural gas increasing to over 500 Bcf once the prices go up to $2.80/Mcf as can be seen in Table 8.1.4.1. This contributes to the flattening of the curve as seen in Figure A8-7 of Appendix 8.1.

6) Northern Mexico

The research by Gas Technology Institute indicate that Mexico's Burgos basin, the largest non-associated gas basin in the country, may contain dramatically larger resources than estimated by the U.S. Geological Survey (USGS) and by Petroleos Mexicanos. In addition, claims have been made by Mexican Energy Undersecretary about expanding production potential from other areas in Mexico. Based on our interpretations of published reports we believe that sufficient non-associated natural gas resource as well as associated gas production could lead to exports of natural gas into the U.S. markets. Pemex, the national monopoly, has traditionally emphasized oil developments but has started to develop strategies for gas exploitation. We believe this would lead to much-needed foreign participation in gas exploration, development and transmission activities in Northern Mexico leading to higher volumes of gas supplies in

Mexico in the future. As shown in Table 8.1.4.1, in year 2015, 100 Bcf gas is available at $2.50/Mcf and 500 Bcf at $2.80/Mcf for exports to the U.S. which contributes to the flattening of the curve as seen in Figure A8-7 of Appendix 8.1.

Table 8.1.4.1. Components of supply sources for generating price/supply curves for Year 2015

Henry Hub Price, 1999$/Mcf	2.40	2.45	2.50	2.55	2.60	2.65	2.70	2.75	2.80
1999 $/MMBtu	*2.33*	*2.38*	*2.43*	*2.48*	*2.52*	*2.57*	*2.62*	*2.67*	*2.72*
Western Canadian Imports, Bcf	2453.5	2464.0	2474.5	2478.0	2481.5	2485.0	2488.4	2491.9	2489.1
L-48 Reservoir Supplies, Bcf	21628.3	21744.5	21860.7	21970.9	22081.1	22191.2	22301.4	22411.5	22495.5
Alaska North Slope, Bcf	338.8	451.8	564.7	564.7	564.7	564.7	564.7	564.7	570.4
MacKenzie Delta, Bcf	277.0	277.0	277.0	400.4	523.8	647.3	770.7	894.1	894.1
Sable Island, Bcf	438.0	438.0	438.0	438.0	438.0	438.0	438.0	438.0	438.0
LNG Distrigas, Bcf	96.1	96.1	96.1	96.1	96.1	96.1	96.1	96.1	96.1
LNG Elba Island, Bcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.8
LNG Cove Point, Bcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.8
LNG Lake Charles, Bcf	67.4	67.4	67.4	67.4	67.4	67.4	67.4	67.4	67.4
Uncharacterized Unconventional, Bcf	0.0	0.0	120.0	240.0	360.0	480.0	600.0	600.0	600.0
Landfill Gas, Bcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ultra Deep Water, Bcf	0.0	0.0	170.0	400.0	600.0	800.0	1000.0	1013.3	1026.7
Onshore Deep Gas, Bcf	0.0	0.0	100.0	200.0	300.0	400.0	500.0	550.0	600.0
Newfoundland, Bcf	0.0	0.0	60.0	200.0	300.0	400.0	500.0	500.0	500.0
Canada Tight, Bcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Northern Mexico, Bcf	0.0	0.0	100.0	200.0	300.0	400.0	500.0	500.0	500.0
Total Supplies, Bcf	25299.1	25538.8	26328.5	27255.5	28112.6	28969.6	29826.7	30127.1	30347.0
Total Supplies, Tbtu	26058.0	26304.9	27118.3	28073.2	28956.0	29838.7	30721.5	31030.9	31257.4

Appendix 8.1.5 Transportation Algorithms in GSAM

Average annual delivered natural gas prices in GSAM are calculated based on the concept of "shadow prices" that quantify the price the natural gas users would pay for consuming an additional unit of natural gas. In other words, GSAM's supply/demand equilibrium quantify "How much better would the entire natural gas transmission system be with one additional unit of gas". These calculations take into account all regions, years, and seasons simultaneously in determining the delivered prices and reflect the value of each potential activity that could be performed relative to adding one unit of gas to arrive at a "marginal activity" and price. Examples of these activities that are tracked in GSAM include: adding pipeline capacity, increasing the level of gas extracted from storage, decreasing the demand for gas in a particular sector. Since the model utilizes all years, regions and seasons simultaneously in its linear programming "objective function" and minimizes the overall net cost to the consumers, it can be considered as having "perfect knowledge". For example, in solving for the supply/demand balance and pricing for year 2005, the model takes into consideration supply volumes, pipeline characterization, demand assumptions, etc., for all the future years which results in lower prices.

Natural gas supply curves are generated for IPM by varying the wellhead prices relative to the base case and running the supply module of GSAM. For the EPA Base Case 2000, a GSAM transportation expansion decision uses a simple algorithm in which new incremental pipeline capacity additions occur at a constant cost (which are same as the existing costs) throughout the projection period. This is due to the fact that we have assumed "rolled-in" rates for any new incremental pipeline capacity expansion with no impact on existing tariffs (i.e. on reservation and commodity charges). In addition, GSAM does not contain intra-regional transmission costs. The transportation differentials are reported as a differential of Henry Hub, a key pricing point in North America for natural gas. The following equation shows all the components of delivered gas price in GSAM.

Delivered Price = Wellhead Price
+ Gas Upgrading Charges + Gathering Charges
+ Variable Transportation Cost + Pipeline Fixed Costs + Distributor Margin

In the following sections, we will describe the reasons for the low transportation adders observed in the EPA Base Case 2000.

1) The actual cost of steel, a primary metal used in pipeline construction, has declined over time. According to the National Association of Steel Pipe Distributors (NASPD) the price of steel has dropped from an average of $560/ton in 1990 to around $360/ton, a 36% decline in 10 years. Key contributing factors are: improved technology in steel manufacture, and excess worldwide capacity of steel. This leads us to believe that our assumption of new pipeline capacity additions at existing costs in real terms is reasonable.

2) According to the Pipeline and Gas Industry journal, although the transmission and distribution margin is projected to increase in nominal dollars, the rate of increase will be less than the inflation rate leading to a real margin decline. This is primarily due to a change in the customer mix (the ratio of residential, commercial, industrial and electricity generator customers), an increase in competition for market share from gas supply sources closer to the market, and from technological innovation. Due to increased competition for market share, the transmission and distribution companies will develop innovative technologies and strive for more efficient operations leading to the assumption that new expansions can occur at existing costs.

3) Most of the projected increase in gas consumption will be from the industrial and electricity generation users. This would lead to a flatter load profile resulting in a reduction in per Mcf fixed cost.

4) There may be a change in the distance gas will have to travel to get to market. This is evident from the Maritimes & Northeast Pipeline project which will likely reduce the average cost of moving gas to the New England market in the future.

5) EIA reports a significant decline in O&M expenses and the unit cost of service for major interstate pipeline companies during the 1988 to 1994 time period in real terms. A decline of 44% in O&M expenses and a decline of over 34% in the total unit cost of service has been reported. This decline can partially be attributed to FERC's adoption of a modified fixed-variable (MFV) method of cost classification in an attempt to reduce underutilization of the national natural gas pipeline system and to make natural gas more competitive in the marketplace. It is our assumption, however, that such costs will decline in the future in nominal terms but a dramatic cost decline cannot occur continuously. Hence the assumption of new pipeline capacity additions occurring at existing costs (in real terms) is reasonable which leads to lower transportation adders.

6) Finally, investigation of likely supply sources in relation to demand regions indicates that currently pipelines in the supply areas are relatively less utilized compared to the pipelines downstream in the market areas. This has resulted in a downward pressure on overall transportation prices.

Appendix 8.1.6 Peer Reviewed Articles for Gas Systems Analysis Model (GSAM)

Peer Reviewed Journal Articles

1. Gabriel, S. A., Vikas, S., Ribar, D. M., "Measuring the Influence of Canadian Carbon Stabilization Programs on Natural Gas Exports to the United States via a 'Bottom-Up' Intertemporal Spatial Price Equilibrium Model," *Energy Economics Journal*, Issue #22, 2000.

2. Gabriel, S. A., Vikas, S., "Computational Experience with a Large-Scale, Multi-Period, Spatial Equilibrium Model of the North American Natural Gas System", *Network and Spatial Economics Journal,* Accepted to be published in special energy issue 2002.

3. Gabriel, S. A., "Gas Model Engine," *OR/MS Today Journal*, 1996

Published Articles Based on Peer Reviewed Abstracts

1. Vikas, S., Gabriel, S. A., Manik, J., "Impact of Electricity and Industrial Demand Growth on Overall US Natural Gas Pricing, Demand and Transportation", published in the technical proceedings of the 24th Annual International Association of Energy Economics (IAEE) International Conference, Houston, TX, 2001.

2. Vikas, S., Gabriel, S. A., Ribar, D. M., "Natural Gas Issues in a High Natural Gas Demand World", published in the technical proceedings of 20th Annual North American Conference sponsored by the United States Association for Energy Economics /International Association of Energy Economics (USAEE/IAEE), Orlando, FL, 1999.

3. Vikas, S., Baron, B., Godec, M., and Ribar, D., "Evaluation of Eastern Canada Offshore Gas Potential and Its Impacts on the Market Share in the North American East Coast", Society of Petroleum Engineers (SPE) Paper No. 40033, 1998 Gas Technology Symposium, Calgary, Canada, 1998.

4. Gabriel, S. A., Vikas, S., Godec, M., and Pepper , W., "A Reservoir-Based Model for Forecasting Natural Gas Supply, Demand and Prices in the North American Gas Market", published in the technical proceedings of the 17th Annual North American Conference sponsored by the USAEE/IAEE, Boston, MA, 1996.

5. Becker A., Godec, M., Pepper, W., and Zammerilli, A., "Gas Systems Analysis Model - Technology and Policy Assessment of North American Natural Gas Potential", Society of Petroleum Engineers (SPE) Paper No. 30187, Micro Computer User's Conference, Houston, Texas, 1995.

GSAM Peer Reviews by Industry, Government and Academic Peers

In addition to the published articles, GSAM's modeling framework, data, and calculation procedures have been peer-reviewed twice by the industry, government and academic peers. The first peer-review was conducted in 1994 when GSAM's first operational version was nearly complete and the second one in the year 1997 when GSAM had been operational for a few years. These peer reviews provided the necessary seal of approval on the effectiveness of GSAM supply, demand, transportation and pricing methodologies.

1st Peer Review Session
Completed in 1994

The first peer review was conducted in October 1994 in Pittsburgh, PA and was attended by natural gas experts from industry, academia, and government. This review provided the acceptance of the basic modeling methodology employed in GSAM and concluded that GSAM was likely to be the most comprehensive gas market model of North America.

The following individuals were involved in the peer review.

ICF Team Presenters	Reviewers	Advisors/Observers
Jerry Breshear	Ram Agarwal, Amoco	Ralph Avellanet, DOE
Leonard Crook	Mian Ahmad, Columbia	Bill Hochheiser, DOE
Mike Godec	Charles Brandenburg, GRI	Tony Zammerilli, DOE
Alan Becker	Robert Brown, Exxon	Elena Melchert, DOE
Dave Cox	John Curtis, Potential Gas Agency	Gene Pauling, DOE
Mark Haas	Ron Charpentier, USGS	John Pyrdol, DOE
Richard Nehring	Richard Snyder, Tenneco	Michael Ray, DOE
William Pepper	Barry Dickerson, MMS	Harold Shoemaker, DOE
	Ronald Edelstein, GRI	Steve George, BDM
	Alan Emanuel, Chevron	Robert Hugman, EEA
	Leon Tucker, AGA	Brian Keltch, BDM

2nd Peer Review Session
Completed in 1997

The second peer review was conducted in February 1997 in Fairfax, VA and was attended by natural gas experts from industry, academia, and government. The Review Committee had a very diverse background in resource assessment, exploration, production, transportation, storage, and end-use requirements and economics of natural gas. They reviewed in detail the data, assumptions, models, and interaction of various aspects of GSAM and DOE's recent uses of the system. The following individuals were involved in the peer review.

ICF Team Presenters **Industry/ Government Reviewers** **Advisors/Observers**

A. Reservoir Data and Modeling

ICF Team Presenters	Industry/ Government Reviewers	Advisors/Observers
Mike Godec	Pramod Bansal, Mobil	Ray Boswell, EG&G
Shree Vikas	John Buffington, MMS	Tony Zammerilli, DOE
	John Curtis, Potential Gas Agency	
	Milton Randall, East Ohio Gas	
	Rick Walker, Mobil	

B. Exploration and Production Modeling

Alan Becker	Bob Brown, Exxon	Bill Hochheiser, DOE
Bob Baron	Bob Hiseler, Mobil	Elena Melchert, DOE
	Ron Charpentier, USGS	Chuck Komar, DOE
	Bill Trapmann, EIA	John Pyrdol, DOE
	Ted McCallister, EIA	Mike Ray, DOE
		Khosrow Biglarbigi, BDM
		William Gwilliam, DOE
		Albert Yost, DOE

C. Transportation/Storage/Demand and Integrating Modeling

Steve Gabriel	Richard Gentges, ANR Pipeline Co.	Christopher Freitas, DOE
Ed Hardy	Andy Kydes, DOE/EIA	Michael York, DOE
Noah Matthews	Leon Tucker, Consultant	Sam Napolitano, EPA
		Ted McCallister, DOE/EIA

Appendix 8.2 Biomass Supply Curves in EPA Base Case 2000

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