TECHNICAL SUPPORT DOCUMENT

THE NATURAL GAS DISTRIBUTION AND NATURAL GAS PROCESSING SECTORS

PROPOSED RULE FOR MANDATORY REPORTING OF GREENHOUSE GASES

Office of Air and Radiation
U.S. Environmental Protection Agency

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1.0 Introduction

1.1 Purpose

This Technical Support Document (TSD) provides an overview of the natural gas and natural gas liquids industries and surveys the current federal reporting requirements of these industries for reporting their fuel production. This review is part of a larger effort to develop guidelines for mandatory reporting requirements for greenhouse gases (GHGs). In December 2007, Congress enacted an omnibus appropriations bill that directs EPA to develop and publish a rule requiring measurement and reporting of GHG emissions above appropriate thresholds in all sectors of the economy. The bill mandates that EPA publish a proposed rule within nine months and a final rule within 18 months. Understanding what information fuel suppliers already generate and report to federal agencies is a first step in developing mandatory GHG reporting requirements.

In considering the broad natural gas industry, we consider the sectors of the industry that could serve as the points for monitoring the entry of natural gas and natural gas liquids into the U.S. economy. The emphasis is on the generation of reports about volumes of natural gas and natural gas liquids and the carbon or carbon dioxide equivalent (CO_2e) associated with the complete oxidation of these products. The report also addresses questions of granularity of data, facility definitions and boundaries, frequency of reporting, validation of reported data, and how data gaps are managed. Finally, the report develops conclusions about the coverage of the data that are reported, key gaps in the data, and questions about data verification and quality assurance and control.

1.2 Organization of this Report

To provide context for the reporting requirements in the natural gas sectors, in section 2 we first provide an overview of the natural gas industry. We begin that with a statistical summary of natural gas production, imports, and consumption. We follow this with a discussion of natural gas industry participants, with brief discussions of each, focusing on the types of information generated in both the natural course of business as well as information developed for and reported to federal government agencies. We also identify the kinds of information typically reported to state government agencies. We also provide an overview of natural gas processing. For the purposes of this rule, natural gas processing is subsumed within the natural gas industry. However, it should be noted that the processing of raw natural gas constitutes a substantial industry that produces natural gas liquids. Natural gas liquids themselves are sources of CO_2 when they are consumed in the economy.

Section 3 is where we describe the current reporting requirements for the industry. It is divided into four subsections. The first three address gas processing, imports/exports, and local distribution companies (LDCs). The final subsection discusses transmission pipelines.

In Section 4, we present our conclusions about overall gaps in the reporting requirements, as well as other issues relevant to data coverage. We also address quality control and reliability of the data reported.

In an attachment to this TSD is a discussion of natural gas price formation and the natural gas value chain and NGL markets.

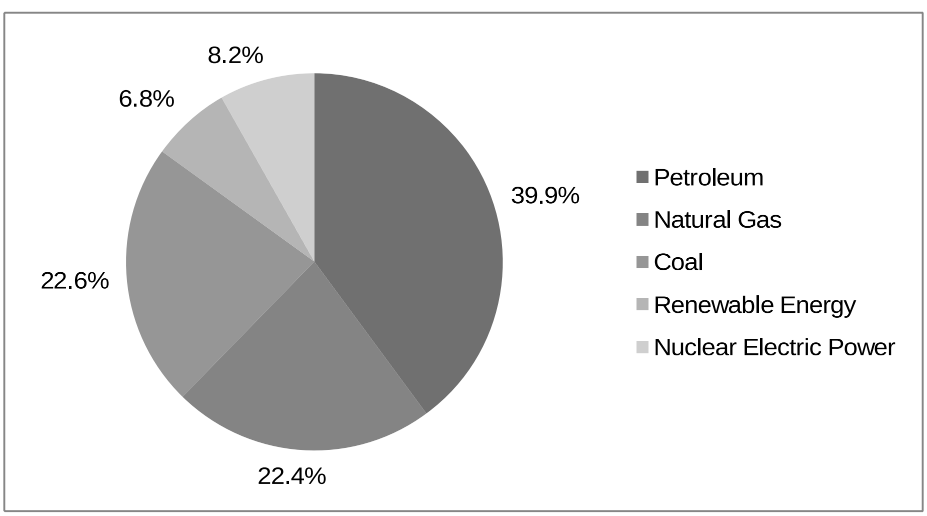
2.0 Overview of the Natural Gas Industry

2.1 The Role of Natural Gas in the Economy

Natural gas is made up of methane (CH_4) and a small amount of other trace gases. It is produced from both gas and oil wells. Gas comes to the surface under high pressure; it is dehydrated at the well site, and sent through small diameter gathering pipelines to natural gas processing plants. The processing plants strip out the extraneous liquids in the gas stream including natural gas liquids (NGLs) such as ethane, propane, normal butane, isobutane, and pentanes; and other gases like CO_2, hydrogen sulphide, nitrogen, helium and water. From processing, gas enters the large diameter, high-pressure pipeline transmission network that delivers gas to large industrial customers and power generators who use the gas as either feedstock or combust it, and to local distribution companies (LDCs). The LDCs step down the pressure and deliver gas to other end users – residences, businesses, industry, power generators – who combust the gas.

Natural gas accounts for about 22% of United States primary energy consumption (EIA, 2006). In 2006, the United States consumed about 21.7 trillion cubic feet (Tcf) of gas. (This is about 22.4 quadrillion Btus or Quads).

Exhibit 1. 2006 Natural Gas Share of Primary Energy Consumption



Source: Energy Information Administration (EIA), *Annual Energy Review 2006 – U.S. Primary Energy Consumption by Source and Sector, 2006*

Exhibit 2. Natural Gas Consumption by End Use (Trillion Cubic Feet)

	2004	2005	2006
Total Consumption	22.38	22.01	21.65
Lease and Plant Fuel	1.09	1.17	1.12
Lease Fuel	0.73	0.75	0.76
Plant Fuel	0.36	0.35	0.36
Pipeline & Distribution Use	0.57	0.58	0.58
Delivered to Consumers	20.72	20.32	19.94
Residential	4.86	4.83	4.37
Commercial	3.13	3.00	2.83
Industrial	7.24	6.60	6.49
Vehicle Fuel	0.02	0.02	0.02
Electric Power	5.46	5.87	6.22

Source: Energy Information Administration, *Natural Gas Navigator – Natural Gas Summary*

In 2006, there were about 450,000 natural gas and gas condensate wells producing 17.9 Tcf of gas. In addition, oil wells produced 5.6 Tcf, for a total of 23.5 Tcf of raw gas.[1] Natural gas processing plants processed about 14.7 Tcf of the raw wet gas. Dry production, that is, what is left after some gas is re-injected for reservoir pressurization, and after the removal of non-hydrocarbon gases, gas plant processing, and the extraction of natural gas liquids, was 18.5 Tcf in 2006 (See exhibit 3). Of this amount, processing plants after extraction losses delivered about 13.8 Tcf into the transmission pipeline network. The balance of the dry marketed production moved directly from wells into the network.

Of the 4.2 Tcf imported by the United States in 2006, 3.6 Tcf were transported via pipeline almost entirely from Canada (a very small amount was imported from Mexico). The balance of the imports of almost 600 billion cubic feet (600 Bcf or 0.60 Tcf) came from LNG shipments from Central America, Africa, the Middle East or Far East. LNG terminals are connected directly to transmission pipelines. The United States also exports natural gas; in 2006 about 724 Bcf of gas was exported. Most of this goes to Canada, and the rest to Mexico and Japan, all of which originates from a small LNG facility in Alaska. Also, a substantial amount of western Canadian gas, flowing through U.S. pipelines, is delivered to eastern Canada. This in-transit gas does not appear in the import/export account and is not combusted in the U.S. Exhibit 4 is a diagram of the natural gas flow in the economy.

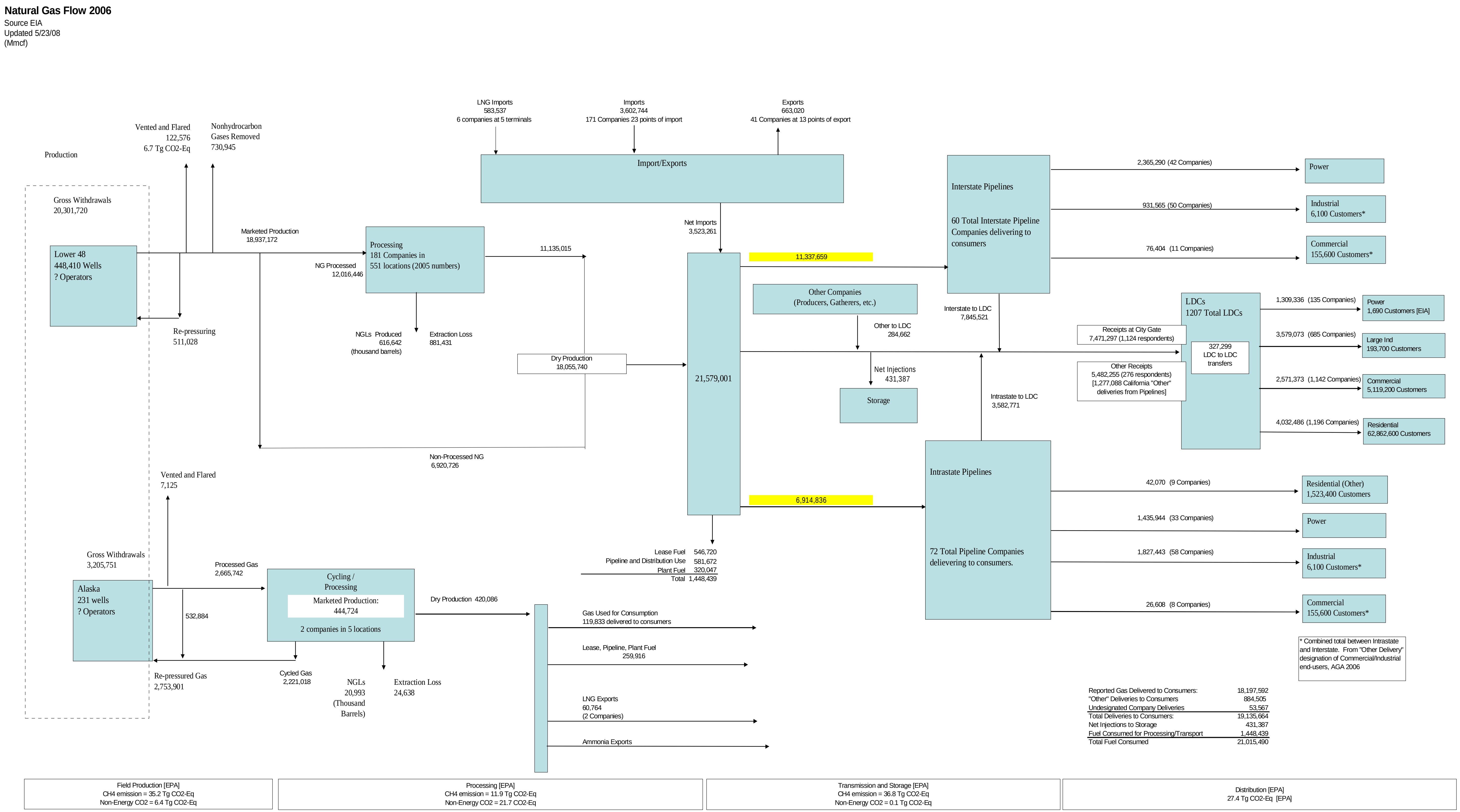
[1] EIA, Natural Gas Annual 2006, Table 1.

Exhibit 3. Natural Gas Production and Imports (Trillion Cubic Feet)

	2004	2005	2006
Gross Withdrawals	23.97	23.46	23.51
From Gas Wells	17.90	17.47	17.94
From Oil Wells	6.08	5.98	5.57
Repressuring	3.70	3.70	3.26
Vented and Flared	0.01	0.01	0.01
Non-hydrocarbon Gases Removed	0.65	0.71	0.73
Marketed Production	19.52	18.93	19.38
Processed Gas	15.19	14.92	14.68
Extraction Loss	0.93	0.88	0.92
Liquids Extracted (bbls)	657,032,000	619,884,000	637,635,000
Dry Production	18.59	18.05	18.48
Imports	4.26	4.34	4.19
Pipelines	3.61	3.71	3.60
LNG	0.65	0.63	0.58
Exports	0.85	0.73	0.72
Available for Consumption/Storage	21.99	21.66	21.94

Source: Energy Information Administration, *Natural Gas Navigator – Natural Gas Summary*

Exhibit 4. Flow Diagram of the Natural Gas Industry



Source: ICF International

2.2 The Role of Natural Gas Liquids in the Economy

Most natural gas produced from wells contains water and various other hydrocarbons that are stripped out of the gas stream by gas processing plants prior to delivering the pipeline quality natural gas into the national transmission pipeline network. The hydrocarbons that are taken out of the gas stream are referred to as natural gas liquids (NGLs). NGLs are themselves sources of carbon emissions and therefore will be monitored under the proposed rule. The principal NGLs and their uses include the following products.

- Ethane (C_2H_6) is a normally gaseous straight-chain hydrocarbon that is a colorless paraffinic gas that becomes liquid under very high pressure (800 psi) or very low temperature (-130^o F). Ethane is a principal feedstock for ethylene, one of the basic petrochemicals for a variety of products.
- Propane (C_3H_8) is the normally gaseous paraffinic compound that becomes a liquid when above 200 psi or below temperatures of -44^o F. Propane is a feedstock for propylene and ethylene and is a significant fuel for heating, cooking, engines, industrial and agricultural uses.
- Normal Butane or n-butane (n-C_4H_{10}) is the normally gaseous straight-chain hydrocarbon that can be liquid at 52 psi. It is used as an additive to gasoline, a feedstock for manufacturing other gasoline blending components, and used directly as a fuel gas for domestic uses, sometimes in mixtures with propane. It is a key feedstock for butadiene, an ingredient of synthetic rubber, as well as for ethylene and butylene.
- Isobutane (i- C_4H_{10}) is the chemical isomer of normal butane that is used for manufacturing gasoline blending components.
- Pentanes plus refers to the NGLs that have five or more carbon atoms and 12 or more hydrogen atoms. These gases become liquid at low pressure, 20 psi or less, and generally are used as feedstock for manufacturing gasoline blending components, blowing agents (pentane), solvents, or other additives to various products.

NGLs are by-products of natural gas production since they must be removed from the natural gas stream in order to maintain natural gas quality for pipeline transportation. Their disposition can vary depending on market prices for NGLs.[2] Any of them can be used as fuels and often are when their value as a fuel at the processor or the refinery may be higher than the value of products manufactured from them. One of the challenges of the rule is that NGLs are often consumed in non-energy uses. On a broad economy wide basis, the disposition of NGLs between energy and non-energy uses can be estimated. But on the basis of individual processing plants, processors may provide these products to customers who may or may not use them for the purposes described above, depending on market conditions.

Sales of NGLs are shown in Exhibit 5 for the years 2000 to 2007. Ethane and propane make up the majority of NGL-products sales, accounting for about 29% and 45%

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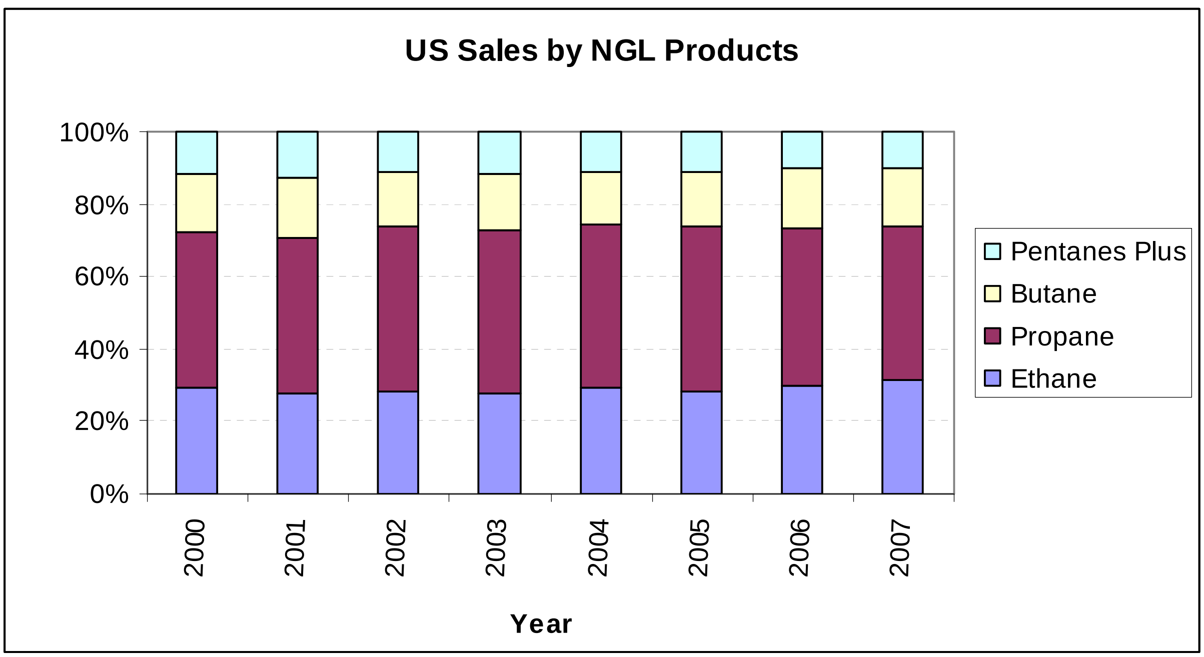
[2] These same products except the ethane are produced in petroleum refineries under the name liquefied petroleum gases or LPGs.

respectively of all sales, followed by butane[3] (about 16%) and pentanes-plus (about 11%). There is year to year variation in the volumes and percentages of NGLs sold, but there is no obvious trend in the numbers. Shares seem to depend on the quantities of natural gas processed and the constituents in the gas as well as how much of the NGLs may be left in the gas to boost heat content. The latter arises from changes in gas prices relative to NGL prices. In periods of high gas prices, more NGLs may be left in the gas stream.

Exhibit 5. U.S. Sales of NGLs

(Billions of Gallons)	2000		2001		2002		2003	
Ethane	13.0	29.1%	11.6	27.7%	12.5	28.4%	11.8	27.5%
Propane	19.4	43.4%	18.1	43.3%	19.9	45.4%	19.5	45.4%
Butane	7.0	15.7%	6.9	16.4%	6.6	15.2%	6.7	15.6%
Pentanes-Plus	5.3	11.8%	5.3	12.6%	4.8	11.0%	4.9	11.5%
US NGL Sales	44.8		41.8		43.8		42.9	

(Billions of Gallons)	2004		2005		2006		2007	
Ethane	12.7	29.1%	11.7	28.2%	12.7	29.8%	13.8	31.3%
Propane	19.9	45.4%	18.9	45.5%	18.5	43.6%	18.9	42.8%
Butane	6.3	14.4%	6.2	15.0%	7.1	16.7%	7.0	15.8%
Pentanes-Plus	4.8	11.1%	4.7	11.2%	4.2	9.9%	4.5	10.1%
US NGL Sales	43.7		41.5		42.4		44.1	



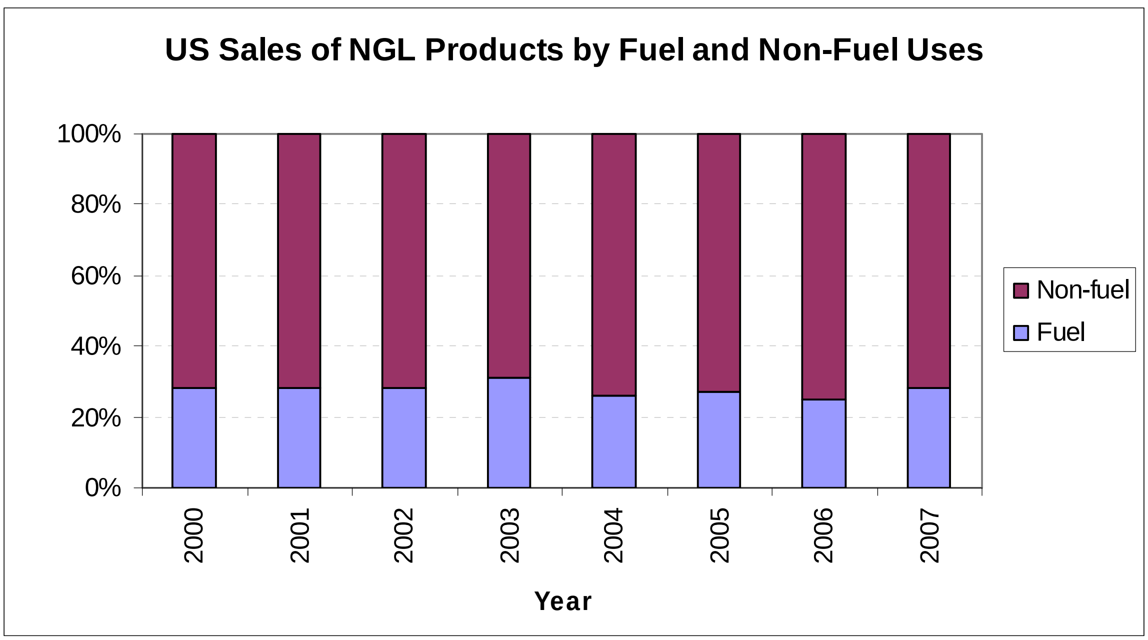
API. "2000-2007 Sales of Natural Gas Liquids and Liquefied Refinery Gases." Table 1.

[3] According to the American Petroleum Institute's (API) survey of NGL and LPG sales in the US, the definition of butane includes: normal butane, isobutane, butane-propane mix, and butylene.

Exhibit 6 presents our estimate of the share of NGLs that are fuel and non-fuel. Fuel uses make up just under 30% of total NGL product sales. Propane is the principal fuel use. A substantial proportion of non-fuel use is in the blending of gasoline, particularly butane and pentanes plus. We have treated this as non-fuel since elsewhere gasoline is counted as a fuel. From 2000 to 2007, the volume of NGL products used for gasoline blending has climbed from 13 to 18-percent of all NGL-products sales. Ethane is almost entirely for non-fuel uses. The detail on each of the products is found in the Appendix.

Exhibit 6. NGL Products Fuel and Non-Fuel Use

	2000	2001	2002	2003	2004	2005	2006	2007
Fuel	28.37%	28.14%	28.15%	30.84%	26.12%	27.30%	24.71%	27.97%
Non-fuel	71.63%	71.86%	71.85%	69.16%	73.88%	72.70%	75.29%	72.03%
Total (Bil. Gal.)	44.8	41.8	43.8	42.9	43.7	41.5	42.4	44.1



API. “2000-2007 Sales of Natural Gas Liquids and Liquefied Refinery Gases.” Table 1

NGLs produced by processors are delivered to other processing plants, refineries, or distributors of NGLs. NGLs may be piped, truck or transported by rail car. An individual processor may not know the disposition of NGLs delivered from the processing facility.

2.3 Emission Thresholds and the Natural Gas Industry

The EPA is considering rules for monitoring requirements on firms and facilities in the natural gas industry. One element of the rules will be establishing thresholds or minimum size requirements for reporting entities tied to the annual emissions derived from the throughput of the facilities and firms. The thresholds being considered are

10,000 and 25,000 metric tonnes per year of CO_2. Converting these thresholds into the equivalent of natural gas yields the following values:

10,000 metric tonnes = 186,608 MMBtu or 183,650 Mcf of natural gas
25,000 metric tonnes = 471,520 MMBtu or 459,125 Mcf of natural gas

These thresholds would not result in a significant reduction in the number of natural gas industry entities that would be subject to monitoring, considering the following:

- In the 2006 ranking of the top natural gas producers, the *Oil & Gas Journal* (Sept. 17, 2007) the 104th largest natural gas producer produced 461,000 Mcf of gas. Thus we can expect that the top 100 producers, accounting for about 80%[4] of gas production would be covered by a 25,000 MT threshold; at the lower threshold the 114th largest producer, at 190,000 Mcf, would be covered by the rule.
- Gas processing facilities range in size from less than 1 MMcf per day to well over 1,000 MMcf/d. The average size is 117 MMcf/d while the median size is only about 40 MMcf/d.[5] The 10,000 MT threshold implies a processing plant that processes just over half a million cubic feet per day; where the 25,000 MT threshold suggests a plant that processes about 1.4 MMcf per day of gas.
- If the rule covering imports focuses on the importing facilities, all of the pipeline import points and LNG import facilities exceed the thresholds. Importers present a different picture, but it is likely that the almost all importers would meet the thresholds. The 10,000 MT threshold implies imports of only 55 Mcf per day; 25,000 MT implies an import rate of 1,260 Mcf per day.
- Virtually all pipelines would exceed the threshold; typical flows are in excess several hundred thousand Mcf per day.
- There are about 1,207 LDCs, with an average throughput of over 9 Bcf per year but a median throughput of only about 120,000 Mcf per year. The 25,000 MT threshold would capture the top 365 LDCs and 99.3% of CO_2 emissions; the 10,000 MT threshold would capture the top 521 LDCs and 99.7% of the CO_2 emissions.[6] See exhibit 7.

Exhibit 7. Threshold Analysis for LDCs

Threshold Level $mtCO_2e/yr$	Total National Emissions $mtCO_2e/yr$	Total Number of Facilities	Emissions Covered		Facilities Covered	
			$mtCO_2e/$ yr	Percent	Number	Percent
1,000	632,100,851	1,207	632,004,022	99.98%	1,022	85%
10,000	632,100,851	1,207	630,106,725	99.68%	521	43%
25,000	632,100,851	1,207	627,543,971	99.28%	365	30%
100,000	632,100,851	1,207	619,456,607	98.00%	206	17%

[4] See Table A-2, Natural Gas Production, Wet after Lease Separation, by Operator Production Size Class (2001-2006) in EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids reserves 2006 Annual Report. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html
[5] *Oil and Gas Journal*, “Worldwide Gas Processing Survey 2006”, June 2007.
[6] EPA calculations based on EIA 2006 Form 176 data.

Source: EPA estimates from EIA Form 176.

The approximately 566 natural gas processing plants produced about 634.7 million barrels of NGLs in 2006.[7] Exhibit 8 presents the impact of thresholds on gas processing plants from the perspective of NGLs produced. The 10,000 MT threshold would cover almost 100% of all the emissions and 400 facilities or 71% of all processors. The 25,000 MT threshold level would cover 99% of all emissions from NGLs covering 347 facilities or 61% of the total number of facilities.

Exhibit 8. Threshold Analysis for NGLs from Processing Plants

Threshold Level $mtCO_2e/yr$	Total National Emissions $mtCO_2e/yr$	Total Number of Facilities	Emissions Covered		Facilities Covered	
			$mtCO_2e/yr$	Percent	Number	Percent
1,000	164,712,077	566	164,704,346	100%	466	82%
10,000	164,712,077	566	164,404,207	100%	400	71%
25,000	164,712,077	566	163,516,733	99%	347	61%
100,000	164,712,077	566	157,341,629	96%	244	43%

Source: EPA estimates based on Oil & Gas Journal (2007)

2.4 Structure of the Natural Gas Industry

Below we provide a brief description of the operating components of the gas industry.

Producers. These are the companies that explore, drill for, and produce natural gas. There are 13,800 producers and about 448,641 natural gas wells in the United States. These companies range from large integrated producers with worldwide operations and interests in all segments of the oil and gas industry, to small one or two person operations that may only have partial interest in a single well. The largest producers are familiar names: BP, Shell Oil, ConocoPhillips, Co., ExxonMobil among others less well known. The 10 largest producers accounted for 8.1 Tcf or 42% of total production in 2006; the largest 20 accounted for 58%; the top 50, 72%. The largest 100 producers accounted for 80% of gas production. In total 93% of U.S. domestic gas is produced by 500 operators.[8]

The five largest producing states are Texas (5.5 Tcf), Wyoming (1.8 Tcf), Oklahoma (1.7 Tcf), New Mexico (1.6 Tcf) and Louisiana (1.4 Tcf). Texas also has the largest number of gas wells at 83,000. West Virginia and Pennsylvania, however, have the next highest number of producing wells (53,000 and 50,000 respectively). West Virginia is the 13th largest producer and Pennsylvania the 15th largest producer.

Producers create and maintain extensive and accurate records on natural gas production in the normal course of business. Royalty payments must be made to landowners and other well partners. State severance taxes require the submission to state agencies of production data and sales. Federal royalty payments are made to the land management agencies and to the Minerals Management Service for offshore outer

[7] *Oil and Gas Journal* (2007) and EIA Annual Energy Review (2008)

[8] EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids reserves 2006 Annual Report. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.

continental shelf production. At the same time, producers are excused from having to file data regularly with the Energy Information Administration (EIA). EIA's reports on production come from data collected from state agencies with Form 895 *Quantity and Value of Natural Gas Production* (Annual and Monthly). State agencies are the central repositories for production data. EIA does collect data from gas well operators in EIA 914, *Monthly Natural Gas Production Report*.

Gathering Pipelines. These are pipelines that collect gas from wellheads in a branch and trunk system and deliver the gas into either a processing plant or a transmission pipeline. They may be owned by the producer or the processing plant, or the affiliate of a transmission pipeline or an independent gathering business. They charge a fee for the service, being a few cents per thousand cubic feet (Mcf), where fees are negotiated between the producer and the gathering pipeline.

Gathering pipelines measure the gas they transport and thus have extensive records on current levels of throughput. They are required to file annual reports of their receipts and deliveries with EIA (EIA 176, Annual Report of Natural and Supplemental Gas Supply and Disposition.). They also must file reports with the Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS). These filings are focused on siting, routing, and safety issues, not throughput. Gathering systems may also report to federal land management agencies and state land use agencies.

Natural Gas Processors. There are about 566 natural gas processing plants in the United States, which were responsible for processing 14.7 Tcf of natural gas and extracting over 630 million barrels of natural gas liquids in 2006. The total processing capacity is about 70 Bcf per day. Typical NGL processing plants have capacities from less than 1 million cubic feet (MMcf) per day to well over 1 Bcf per day.

There are three major types of processing plants. Small processing plants at or near the wellhead strip out water and hydrocarbon liquids (condensate) before the gas moves into the gathering systems. These plants are integrated with the well production. Large processing plants, resembling refineries, process the bulk of the processed gas. They receive gas from gathering pipelines (and in some cases from other processing plants) and strip out the NGLs along with non-hydrocarbon gases such as CO_2 and hydrogen sulphide (H_2S). Some processing plants only remove the non-hydrocarbon gases. Straddle processing plants are located on pipelines closer to market and strip out accumulated liquids that were not removed farther upstream.

Processing is a "mid-stream" business where the major players are often associated with producers and large field services companies. Some of the more prominent processing companies are Duke Energy Field Services, Williams Companies, BP PLC, Enbridge Energy Partners, Oneok, Hess, and ExxonMobil.

Processing economics can be complicated due to the production of joint products from the plants – that is, dry pipeline quality natural gas and NGLs. Because of the volatile swings in gas and NGL prices, most commercial arrangements are "split proceeds" deals in which NGL revenue is shared between the gas producer and processor while the producer retains title to the dry gas. Processors receive additional compensation for the cost of removing non-hydrocarbon gases. However, in most instances of poor quality gas, the producer himself builds and operates the gas processing plant (since it must be designed for the specific gas composition).

In 2006, NGL processors processed for about 75% of domestic marketed dry production, or 13.8 Tcf out of 18.5 Tcf. The remaining 4.7 Tcf of domestic production typically moves directly into the transmission pipeline system since it can meet pipeline specifications without processing. (In part this is due to small streams of gas from many small wells entering the system far downstream from the production regions, where the small amounts of unprocessed gas are comingled with huge quantities of dry processed gas. The unprocessed gas liquids simply are not noticed.) While measuring gas at processing plants can be straight forward, given there are meters at the outlet of the plants measuring both gas and liquids, the sources of non-processed gas are more diffuse. Much of the gas produced in Appalachia and some of the coalbed gas produced in the Rockies can meet pipeline specifications without processing.

The major reporting requirements for processors are to EIA in forms 64, *Annual Report of the Origin of Natural Gas Liquids Production,* and 816, *Monthly Natural Gas Liquids Report.* (EIA has proposed a new form, out for public comment, Form 757 *Survey of Natural Gas Processing Plants* which appears aimed at understanding plant capabilities before and after emergencies. It would not collect data useful for this rulemaking.) None of these forms offers a clear definition of “processing plants,” and as a consequence depending on these reports would limit the coverage of the industry. For example, condensate and liquid separation at the wellhead in associated gas wells appears not to be included in these reports. Nearly all wells have some form of processing, in particular condensate and oil wells producing oil and gas. Notwithstanding the limitations of these forms, s a general business matter, processing plants keep track of how much dry gas they deliver into pipelines and of the amounts of NGLs they deliver to customers. The major challenge with using this sector to monitor how much natural gas enters the economy is that only 75% of gas goes through these plants.

Transmission Pipelines. These are the large diameter, high pressure systems that move gas from producing regions to the consuming regions. There are about 160 pipeline companies in the United States, operating over 300,000 miles of pipe. Of this, 180,000 miles of pipe are operated by interstate pipelines. This pipeline capacity is capable of transporting over 148 Bcf of gas per day. Transmission pipelines do not own the gas but transport it on behalf of their shippers for a fee. Interstate pipelines operate under public tariffs approved by Federal Energy Regulatory Commission (FERC). Intrastate pipelines operate within single states and are regulated by state agencies. Intrastate pipelines typically negotiate their fees with shippers and may own the gas they transport. A third category of transmission pipes are so-called “Hinshaw” pipelines. These are large, high-pressure transmission pipes owned by a LDC operating solely within the borders of a single state that carry gas from interstate pipelines to LDC facilities. They are regulated by state public utility commissions. Examples include Pacific Gas & Electric and San Diego Gas & Electric.

Major pipeline companies include El Paso Corp., Williams Companies, Spectra, and Kinder Morgan. Each of these owns several major interstate pipelines. Large intrastate pipelines include KM Tejas, Bridgeline, Sabine, and Oasis.

The major components of pipelines include the receipt and delivery meters, compressor stations, and the pipe itself. Pipelines can have hundreds of receipt point meters where gas is delivered into the pipeline directly from gathering pipelines, processing plants, LNG facilities, or other transmission pipelines. The delivery point meters measure deliveries to other pipelines, LDCs, storage facilities, and end users. Pipelines must maintain a balance between receipts and deliveries on a daily, monthly, and annual basis. Shippers' bills are based on these meter readings and over the course of a year are reasonably accurate. (Pipelines retain gas for operating compressors and for lost and unaccounted for amounts – this is mostly from meter discrepancies.)

All pipelines submit reports on annual throughput, receipts and deliveries to EIA under Form 176. This is the major source of information on pipelines. Interstate pipelines must file *Annual Reports* with the FERC (FERC Form 2/2A). This form mainly covers accounting matters but includes a section on gas accounts that lists total receipts and deliveries. Pipelines also are required to submit FERC Form 567, *System Flow Diagram*, that includes among other things, average daily volume received at each intake point to the transmission system as well as average daily volumes delivered at each delivery point on the system.[9] Access to this information is restricted due to Critical Energy Infrastructure Information (CEII) rules. Like gathering pipelines, transmission companies report to the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) on siting and pipeline physical characteristics, but not flows. The major challenge to using pipelines as the point for monitoring natural gas is double counting. Pipelines receive gas from other pipelines and deliver to yet other pipelines, as well as to LDCs and end users. Reconciling the receipts and deliveries between pipelines can be very complex.

Marketers. Natural gas marketers purchase gas from producers and other marketers, and then contract with pipelines to transport the gas for re-sale to end users and LDCs. Some marketers are more active in wholesale markets and supply large industrial concerns. Others are active in LDC markets that have customer choice programs, and sell to small end users including residential and commercial customers. Marketers engage in activity along the value chain: they contract for capacity on pipelines, storage facilities, and LNG terminals; they import and export gas; and are often the customers of processing plants. There are hundreds of marketers from very large companies to single operators. The five largest marketers in the United States and their daily average volumes for 2006 were:

ConocoPhillips	13.50 Bcf/d
Shell Energy	11.70 Bcf/d
Sempra	11.35 Bcf/d
Constellation	7.39 Bcf/d
Chevron*	7.70 Bcf/d

Source: *Natural Gas Intelligence*, http://intelligencepress.com/features/rankings/gas/

Marketers submit reports to the Department of Energy, Office of Fossil Energy, where they are importers or exporters of natural gas. EIA Form 910, *Monthly Natural Gas Marketer Survey*, collects statistical information from marketers in states where there are

[9] See FERC regulations at 18 CFR 260.8.

customer choice programs in place. (Customer choice programs allow end users to choose their gas suppliers. Retail marketers are active in these states.) A new FERC Form 552, *Annual Report of Natural Gas Transactions* requires wholesale buyers and sellers of gas to report total volumes purchased and sold along with certain pricing terms. In short, there is no single source of information that would cover the activities of all marketers in a consistent way, as many marketers do not file data at all.

Storage Operators. We do not cover this sector because it manages gas supplies within the system. No new supply enters the system through storage operations nor do storage operators supply directly to end users. Gas is stored in underground facilities that can include hollowed out salt caverns, but mostly are depleted gas fields. Storage is a way for operators to store gas during the non-heating season and withdraw it during the heating season. Most storage therefore is seasonal. High deliverability storage, that which is in salt formations, can cycle stored gas more frequently than once per year. Storage operations account for only about 3 to 4 Tcf of gas consumed. In any one year storage can add to the amount of gas consumed if more is withdrawn than is injected. But stored gas is not “new” to the system. The complicating factor presented by storage in terms of monitoring fuel-based emissions is the time lag: gas can be produced in one year, stored, and consumed in a following year.

Local Distribution Companies. There are about 1,200 natural gas distribution companies in the United States, with ownership of over 1.2 million miles of distribution pipe mains and service lines, mostly in cities and towns. Major LDCs include companies like Consolidated Edison Co. (New York), Atlanta Gas Light Co., Pacific Gas and Electric Co. (Northern California), Peoples Gas (Chicago) and large municipally owned systems like Philadelphia Gas Works and Memphis Light Gas & Water. Many municipal systems are very small, some with only a few hundred customers. LDCs account for about 60% of gas consumed in the economy. The balance is gas delivered directly to industrial customers, including power plants, by pipelines.

LDCs purchase gas from producers and marketers, often at market hubs or the outlet of gas processing plants (often the same thing), and transport the gas to their facilities via the transmission pipelines. LDCs are the major shippers on transmission pipelines, controlling much of the contracted capacity. LDCs fall under the jurisdiction of state public utility commissions who oversee rate setting, customer service, and financial management.

Entry of gas into LDC systems is usually by delivery of gas at a city gate station where pressure step-down begins for local consumption by LDC customers. (Some LDCs own high pressure transmission pipes to move gas between facility locations prior to pressure step-down for distribution. These include the large California distributors as well as others.) LDCs own most of the gas they distribute, although there are exceptions, such as where customer choice programs are in effect. In these programs, consumers purchase gas from marketers or other suppliers and only pay a fee to the LDC to deliver the gas. (Atlanta Gas Light, for example, owns little of the gas it distributes.) Where LDCs transport gas on behalf of their customers, taking no ownership of it, they charge a transport fee. In traditional LDC operations, sales customers are charged for the gas as well as the distribution costs and a share of the upstream transmission and storage costs.

LDCs meter their gas receipts and distinguish between gas for resale and gas transported on behalf of others. They submit data to EIA in form 176 on gas receipts for distribution and transportation. They also submit reports to state regulators on gas throughput. Where LDCs import (or export) gas, they will file reports with the DOE's Office of Fossil Energy.

LDC rates and revenues are tied to the amount of gas received and delivered, and records are generated and maintained for billing. The data are routinely aggregated by customer rate class and for the entire system. A major data processing effort is the conversion of aggregate billing cycle data – that is data collected by the reading of customer meters on a set schedule for different areas of the system – to calendar-based data. This is necessary to reconcile transmission pipeline receipts with customer sales and deliveries. From all these activities, LDCs know how much gas they receive and how much gas they deliver and sell.

LNG Terminals. LNG terminals receive shipments of LNG, store it in insulated tanks, and then vaporize it for delivery into transmission pipelines. There are five operating terminals in the U.S. currently receiving LNG imports. These are located on the East and Gulf Coasts. An offshore terminal has been constructed in the Gulf and another has recently completed construction on the coast of Louisiana. Another 22 onshore projects have been approved by the FERC and three offshore projects approved by the Maritime Administration (MARAD) and Coast Guard. Two of these projects are already under construction. Terminals must be certificated by FERC or the Coast Guard depending on whether they are onshore or offshore.

The owners/operators of terminals are often transmission pipelines or independent third parties; Cove Point, the LNG terminal in Maryland, is owned by Dominion Resources, owners of Dominion Pipeline; El Paso Corporation owns Elba Island terminal. Suez Energy International owns the Distrigas terminal in Boston. Terminals operate much like pipelines, with a FERC approved tariff that sets fees for the throughput. Capacity holders at the terminals are usually marketers and thus will appear as the importers of record.

Terminal operators must provide reports to the EIA in Form 176. Terminals also submit FERC Form 2, *Major Natural Gas Pipeline Annual Report*. Unlike for transmission pipelines, Form 2 data for terminals is potentially useful for monitoring natural gas imports as the form shows the receipts of gas at the terminal. Much of the other reporting at terminals is related to ship movements, safety issues, and other physical issues not related to throughput. Importers of gas through the terminals file reports with DOE.

Summary. In every sector of the gas industry, gas flow is monitored carefully since it is the source of revenue. Some of the data are reported to the federal government and some to state governments. In every case, however, data are routinely collected, aggregated, and verified as the basis for executing sales and billing customers.

3.0 Industry Federal Reporting Requirements

In this section we focus on the three sectors identified as points of monitoring of natural gas: natural gas processors, imports, and LDCs. The following discussion is based on the information gathered on current reporting requirements and presents an interpretive narrative of the reporting matrix spreadsheets compiled for EPA. We focus our discussion on the reporting requirements most relevant to the determination of an accurate accounting of gas flow through the gas system.

For each sector, we discuss the key reporting obligations by agency and reporting form. We then address the key questions EPA has identified for evaluating the suitability of the reporting requirement as a basis for EPA's mandatory monitoring system. These questions include:

- What is reported? e.g., gas received, gas delivered, NGLs
- Is the reporting tied to a facility or entity at a facility?
- What is the threshold for reporting?
- What is the frequency of reporting?
- How is the data developed?
- What are the verification/certification, QA/QC methods?
- How public is the information?
- Where are the gaps in sector coverage that would lead to un-accounted for volumes?

3.1 Natural Gas Processing

Energy Information Administration

EIA Form 64A is used to gather information on natural gas inputs into processing plants. The form also collects information on amount of natural gas liquids produced.

Report Name: EIA-64A, Annual Report of the Origin of Natural Gas Liquids Production	
What is reported	1) Gas liquids volumes extracted from "on-site" processing (includes plant condensate and scrubber oil) 2) Natural gas volumes received (does not include refinery off-gases) by state of origin of gas. 3) Gas shrinkage resulting from natural gas liquids extraction. Shrinkage is estimated for each component (ethane, propane, butane, etc.) 4) Natural gas used as fuel in processing
Who is reporting	Processing plants (including cycling plants)
What is the threshold for reporting	No minimum; all plants report
What is the reporting frequency	Annual
How are the reported data developed	EIA does not specify on monitoring; potentially from meter readings.
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Processing plant level (includes information on both owner and operator)

What are the verification/certification & QA/QC methods	Required to keep all records necessary to reconstruct the data reported on this form for a period of three years
Is the data public or restricted	Disclosure limitation procedures are applied to the statistical data published from EIA-64A survey information.
Where are the gaps in the data reported	1) Total gas going out of the processing plant cannot be reliably estimated, since the non-hydrocarbon extraction is not known (shrinkage only accounts for hydrocarbon liquids extracted). 2) Individual quantities of products are not accurate since proportions of each product estimated from the EIA Form 816 are applied to the total volumes produced reported in Form 64A.

EIA Form 816 is used to collect mass balance information on products from processing plants. This includes inputs, stocks, receipts, production, and shipment of products. The form also collects data on natural gas and products used as fuel.

Report Name: EIA 816, Monthly Natural Gas Liquids Report	
What is reported	1) Stocks - This refers to measured inventories of stocks in custody (regardless of ownership). 2) Receipt - This refers to products received at the plant and in transit to the plant, including intra-company transactions. 3) Inputs - This refers to quantities of product converted into some other product through isomerization (e.g. conversion of normal butane into isobutane). 4) Production - This refers to gross production of products. 5) Shipments - This refers to shipment of products out of the plant, including to other plants, storage facilities, refineries, chemical plants, or fractionating facilities. 6) Plant fuel use and losses - This refers to products consumed in-plant for all purposes, including non-processing losses (e.g. spills, fires, losses, contamination, etc.).
Who is reporting	All facilities that extract liquid hydrocarbons from a natural gas stream and/or separate a liquid hydrocarbon stream
What is the threshold for reporting	Processing plant and fractionators
What is the reporting frequency	Monthly
How are the reported data developed	EIA does not specify monitoring methods; potentially from meter readings
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Processing plant, fractionator level (reporting company may be owner or operator, the form does not identify them separately)
What are the verification/certification & QA/QC methods	Not specified in the instructions to the form
Is the data public or restricted	Kept confidential but used in EIA statistics
Where are the gaps in the data reported	Sometimes products extracted from gas are converted into other products (e.g. butane to isobutane). Therefore, production and shipments are not the most accurate measures of how much of each product is going into the economy. The reporting is complete, but the accounting might have to be worked out. One possible solution is to use production minus inputs as a measure of net production.

EIA 176 aims at collecting information from processing plants that deliver directly to consumers or who transport gas to, across, or from a State border using field or gathering facilities. This appears to severely limit the information gathered from processors. For this reason we do not include this form as relevant to processors.

<u>Summary</u>

These forms in combination provide an incomplete picture of the key outputs of processing plants. There are two main issues with the data from these forms. First in reviewing the mass balance data collected by EIA we have had difficulty sorting out processing and processed gas from the general stream of gas entering the system. Secondly, there is a broad range in the sizes of the named processing plants that highlights the problem of definition. Lower 48 plants range in size from about 1.8 billion cubic feet (Bcf) per day capacity down to 400 thousand cubic feet (Mcf) per day of capacity. (Prudhoe Bay has an 8.7 Bcf per day processing plant.) This size range suggests plants are serving different functions that are not captured in the EIA reported volumes. Furthermore, some form of processing occurs at several stages in the gas system, aimed at doing special things:

- Condensate and liquid separation at the wellhead (associate gas wells) – virtually all wells have some sort of processing occurring at the well site to remove water and other liquids. This is especially so at condensate wells that produce natural gasoline and oil wells producing oil and gas jointly. Most of this probably goes on to centralized processing; some may enter the pipeline system.
- Removal of NGLs – this is what people generally think of when they speak of what processing plants do, and indeed, the Lieberman-Warner bill defines processing plants as such. But it does not define natural gas liquids. EIA counts only plants that remove NGLs as processing plants.
- Removal of non-hydrocarbon gases and dehydration – some processing plants remove water and non-hydrocarbon gases (principally CO_2). These are NOT considered to be processing plants for purposes of EIA data collection or any other data collection programs currently in place. Some of this gas may enter the pipeline network.
- Liquids traps at pressure drop locations e.g., LDC city gates –liquids removal (water and NGLs) occurs downstream of the producing sector at pipeline straddle plants and at LDC city gates.

Thus a major issue with processing as a point of monitoring natural gas is the definition of processing plants and addressing the question of double counting. The inventory of gas processing plants that constitute the 566 plants is not the full universe of plants nor do we know if they are the plants that process the volumes reported by EIA. The other major question regarding monitoring natural gas at processing plants is that a substantial portion of natural gas does not go through processing plants, rather it goes directly into the pipeline network. No agency or entity keeps track of these volumes.

3.2 Natural Gas Imports and Exports: Pipelines and LNG

<u>Department of Energy, Office of Fossil Energy.</u>

The U.S. imports gas through pipelines and LNG terminals. Under Sec. 3 of the Natural Gas Act (1938), importers and exporters of natural gas must receive authorization from the DOE's Office of Fossil Energy (OFE). The importers and exporters are the entities who hold title to the gas and are typically not the owners of the pipeline, LNG facilities or LNG ships, though the facility owners own and operate the meters used to measure the throughput. Permits are for short term spot imports/exports (so-called blanket authorizations) or long term authorizations. OFE requires importers/exporters to submit annual reports of the volumes of gas or LNG they import and export. The key elements of these reports are described below.

Report Name: Natural Gas Imports by Pipeline; LNG Imports; Natural Gas Exports by Pipeline, LNG Exports	
What is reported	Volume of gas (Mcf) and landed price $/MMBtu, owner of gas
Who is reporting	Importers/exporters with authorizations
What is the threshold for reporting	No minimum; all imports/exports are reported
What is the reporting frequency	Monthly
How are the reported data developed	For pipelines, from transmission meter readings; for LNG offloading measurements and meter readings
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Pipelines at the specific border crossing; LNG at named terminals
What are the verification/certification & QA/QC methods	Not known. As mandatory reports there may be sanctions. DOE tracks and publishes summary data.
Is the data public or restricted	Importer specific data is restricted; total imports/exports are public for individual import and export points.
Where are the gaps in the data reported	Coverage of imports and exports appears complete. Clarification needs to be made for in-transit volumes.

Federal Energy Regulatory Commission

The annual reports provided by LNG terminals include annual volumes of gas received and delivered at the terminal.

Report Name: Major Natural Gas Pipeline Annual Report, FERC Form 2	
What is reported	Volume of gas (Mcf), ownership
Who is reporting	Terminal operator
What is the threshold for reporting	No minimum; all imports/exports are reported
What is the reporting frequency	Annual
How are the reported data developed	Metered at the terminal
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Name of the terminal
What are the verification/certification & QA/QC methods	Not known. As mandatory reports there may be sanctions.
Is the data public or restricted	Public
Where are the gaps in the data reported	None apparent although some of the submissions appear confusing. Clarification required.

Energy Information Administration

EIA's Form 176, *Oil and Gas Survey*, includes data gathered at the facilities that transport gas across borders or import LNG. Unlike DOE's OFE, it is not focused on the parties that own the imported or exported product, but on the facilities that transport the gas across the border or receive LNG imports. Companies are required to submit imports/exports by state and not by individual border crossing.

Report Name: EIA 176, Oil and Gas Survey.	
What is reported	Volume of gas (Mcf), owner
Who is reporting	Transmission pipelines and LNG terminals
What is the threshold for reporting	No minimum; all imports/exports are reported
What is the reporting frequency	Annual
How are the reported data developed	For pipelines, from transmission meter readings; for LNG offloading measurements and meter readings
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Pipelines by state; LNG by state
What are the verification/certification & QA/QC methods	There seems to be some time series checking for reasonableness and internal consistency checking. Sanctions are available for failure to comply and report accurately.
Is the data public or restricted	Importer specific data are restricted.
Where are the gaps in the data reported	Use the same form for all commodity imports, but appear to be no gaps. It is not clear that subsequent pipeline deliveries would always add up to the original transaction delivery quantity, so it may not be totally accurate.

U.S. Customs and Border Protection

Customs monitors imports for duty collection (as appropriate – there is no duty on Canadian imports of natural gas). The basic customs forms are used for all commodities and thus are not tailored to natural gas. This only covers imports.

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Report Name: Customs Form CF 3461 - Entry/Immediate Delivery; Form CF 7501 Entry Summary.	
What is reported	Volume and value
Who is reporting	Importer of record.
What is the threshold for reporting	No minimum; all imports/exports are reported
What is the reporting frequency	Per transaction/vessel delivery
How are the reported data developed	Per the manifest or bill of lading
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Point of entry to U.S., plus information on point of origin
What are the verification/certification & QA/QC methods	Sanctions are available for failure to comply and report accurately.
Is the data public or restricted	Facility specific data are restricted.
Where are the gaps in the data reported	Reports of imports/exports are aggregated by state; individual facility locations not identified.

Summary

Imports and exports appear to be captured in the reporting to DOE's OFE. The information is reported by the authorized importer/exporter at specific border crossings, where one can identify the pipeline actually transporting the gas or the LNG terminal that receives the LNG. FERC's annual report also provides public information on terminals.

There is another category of gas that crosses borders, so-called in-transit gas that enters the U.S. at western border crossings bound for eastern Canada. The gas is not consumed here. OFE collects data on in-transit gas. EIA's Form 176 makes no distinction between in-transit and gas that is imported. Presumably, it captures this gas in the export volumes it collects. Customs data, being transaction-based, would require aggregation to be useful and even then may not provide an accurate reflection of the gas received by pipe.

3.3 Local Distribution Companies

Energy Information Administration

Local Distribution Companies are required to submit both monthly and annual reports on deliveries and transfers to consumers under the Federal Energy Administration Act of 1974. The two forms are the EIA 176 and EIA 857.

Report Name: EIA-176, Annual Report of Natural and Supplemental Gas Supply and Disposition	
What is reported	Gas volume (Mcf) and revenue (whole dollars) of deliveries by company, sector delivered to and sales vs transportation
Who is reporting	All companies that take physical possession of natural gas during reporting period
What is the threshold for reporting	No minimum
What is the reporting frequency	Annual
How are the reported data developed	Based on billing information
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Delivery data reported at company level.
What are the verification/certification & QA/QC methods	Computer programs and other tests verify reported data and check for reasonableness and consistency. Where problems are identified, respondents are contacted and required to amend forms with corrected data.
Is the data public or restricted	All reported data are public, with the exception of the name of specific companies with which natural gas transactions occurred.
Where are the gaps in the data reported	No gaps in the data are apparent except where companies fail to comply.

Report Name: EIA-857, Monthly Report of Natural Gas Purchases and Deliveries to Consumers	
What is reported	Gas volume (Mcf) and revenue (whole dollars) of deliveries by company and sector delivered to.
Who is reporting	Respondents are from a statistically selected representative sample of companies that deliver natural gas to consumers.
What is the threshold for reporting	No minimum
What is the reporting frequency	Monthly
How are the reported data developed	Based on meter readings
Are reports mandatory or voluntary	Submissions are mandatory
What is the facility level of the reporting	Delivery data reported on company level.
What are the verification/certification & QA/QC methods	Discrepancies between Form 857 and Form 176 are noted and respondents are required to file corrections.
Is the data public or restricted	Data are protected and not released to the public.
Where are the gaps in the data reported	As a statistical sample survey, it does not cover all the industry. Sources of error include consistency with categorizing customers by end use sector since most LDCs categorize by rate class.

Summary

In terms of federal reporting, LDC's submissions of EIA 176 Forms, appear to be the most complete information available in this sector. It should be noted that LDCs also develop information for purposes of billing, rate-making, and for submissions to state regulators that should be the same as that which is developed for EIA. A problem with this data is related to LDC end use breakdowns based on rate classes which are not necessarily consistent between LDCs. Also, missing from these data are end-users that do are not on the LDC system. These will be large end users like power plants or large industrial plants that receive gas directly from transmission pipelines.

3.4 Transmission Pipelines

Energy Information Administration

EIA's Form 176, Oil and Gas Survey, is a principal public source of information about pipeline transmission throughput that cuts across the entire transmission sector – interstate and intrastate pipelines. Gathering pipelines also may be included.

Report Name: EIA 176, EIA-176, Annual Report of Natural and Supplemental Gas Supply and Disposition	
What is reported	Volume of gas received, and disposition by company, state and end use sector
Who is reporting	Transmission pipeline
What is the threshold for reporting	No minimum; all volumes are reported
What is the reporting frequency	Annual
How are the reported data developed	From pipeline receipt and delivery metering

Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Pipeline, by state by end use sector. No specific receipt/delivery point information
What are the verification/certification & QA/QC methods	Sanctions are available for failure to comply and report accurately.
Is the data public or restricted	Pipeline specific data are restricted.
Where are the gaps in the data reported	The data are fairly aggregate. They do not account for the fact that pipelines deliver gas to other pipelines, thus summing across pipelines would lead to double or triple counting or worse.

Federal Energy Regulatory Commission

FERC Form 567, Annual Flow Diagram, is a reasonably detailed representation of gas pipeline infrastructure and flows. Specifically it reports annual average daily receipts and deliveries by each metered receipt and delivery point on the pipeline. Receipt and delivery points can be manually mapped to facilities being served, e.g., LDCs, industrial plants, other pipelines. Receipt points can be manually paired with processing plants, gathering pipelines, other inter or intrastate pipelines. Historically this information has been public, but since 9/11 it has come under the CEII restrictions and is not available to the public.

Report Name: Form 567, Annual Flow Diagram	
What is reported	Average daily volume of gas (Mcf) by pipeline by receipt and delivery point
Who is reporting	Interstate pipelines only
What is the threshold for reporting	Pipelines with throughput greater than 100,000 Mcf/d which captures virtually all interstate transmission lines
What is the reporting frequency	Annual
How are the reported data developed	Metering and engineering data
Are reports mandatory or voluntary	Submissions are mandatory.
What is the facility level of the reporting	Pipeline, pipeline receipt and delivery points
What are the verification/certification & QA/QC methods	Not known. There are sanctions for not filing. Often the data are subject to interpretation and can be confusing.
Is the data public or restricted	Public but restricted under CEII
Where are the gaps in the data reported	Does not cover intrastate transmission.

Interstate pipelines are also required to submit FERC Form 2, Reports, wherein pipelines must report annual receipts and annual deliveries. It is very aggregate and there is substantial double counting where pipelines report annual throughput that includes receipts from upstream pipelines and deliveries to downstream pipelines. This would be impossible to untangle from this form. We have not included it as a useful source of information.

Summary

There is substantial information generated internally in transmission pipelines for operations and billing. The difficulty would be in avoiding the double counting that arises where pipelines deliver to each other. They know this information since all pipeline interconnects are metered and the pipes know how much they deliver and receive from each other. But this is not reported to federal agencies, except in FERC Form 567, and the information reported does not solve the issue of double counting mentioned above. To account for pipeline to pipeline transfers and avoid double counting with billing accuracy, would require some significant investment in systems that do not exist at present.

4.0 Data Gaps and Quality

In this section we discuss the options for establishing reporting requirements and consider some of the major gaps in currently reported data and quality issues.

4.1 Reporting Options in Natural Gas and Coverage Gaps

The options for where to monitor natural gas entering the economy are discussed below, taking into consideration the current reporting done by the industry.

- Require processors to report natural gas deliveries to pipelines. Under this approach (the approach taken in the Lieberman Warner Bill) the point of monitoring would be the processing sector. This will not capture all of the natural gas entering the system. As noted in our overview section, of the 18.5 Tcf of gas dry marketed production in 2006, only 13.8 Tcf flowed from gas processing plants that produce NGLs. The remainder, about 4.7 Tcf, or 25% of domestic gas entering the national pipeline transmission system bypasses NGL processing plants.
    - Require producers whose gas does not go through processing prior to entering the pipelines to monitor and report to EPA. To avoid confusion over what constitutes processing, EPA could identify the 566 processing plants and require anyone whose gas does not go through those plants to be subject to mandatory monitoring. We do not know how many producers this could entail. Possibly it could be a large number, if for example, much of this gas comes from Appalachian production where there are large numbers of small producers. (Also some Rocky Mountain coal bed methane production requires little if any processing.)
    - Require pipelines to monitor receipts of gas from gathering systems that do not go through the named processing plants. Pipeline operators should know who is behind the receipt meters, and particularly where gas may be entering that is not processed.
- Require reporting by producers, not processing plants. As noted in our report well operators must keep accurate records on production to fulfil contract obligations to royalty owners and for paying state severance taxes. The federal government receives royalty payments from well operators. Reports are routinely filed with state agencies, which are the main source of all national production statistics. The challenge of this approach is that there are approximately 450,000 gas producing wells and 13,800 producers, of which the largest 500 account for about 93% of the production. There currently is no

national data gathering system that collects information to one location for produced gas.

Require gas also to be reported at import locations (pipeline border crossings) and at LNG facilities to account for gas that would not be covered by domestic producers. There are a small number of border and LNG import facilities. These volumes are already reported. Adjustments would have to be made for gas transported through the United States for delivery in Ontario, Canada.

- Require transmission pipelines to report natural gas throughput. There are about 160 pipeline transmission companies and 300,000 miles of pipeline. Virtually all of the natural gas in the economy moves through this system. Pipelines meter the flows across all the receipts and delivery points. There are several challenges to having pipelines report. First is the complexity of the system due to the fact that pipelines receive gas through receipt meters from other pipelines, and deliver gas at their delivery meters to other pipelines. Each pipeline will have hundreds and maybe thousands of receipt and delivery meters. There would be a substantial effort necessary to avoid double counting. Second, pipelines do not always know who is on the other side of the meter, since the shipper of record is a marketer. They may not be in a position to resolve double counting questions. Third, as a matter of normal business operations, gas is tracked throughout the pipelines both for operational and billing purposes. Operational volume data are essentially estimations and require a substantial effort in reconciliation to generate billing quality data. This is because gas is a compressible fluid, the measurement of which with meters across a system is inherently an approximation due to the differing flow and pressure conditions in the pipeline system through time. There is a time lag between metered and billed data. In sum, the challenges to pipeline reporting are significant.
- Require LDCs to report gas for distribution to end users. LDCs receive gas from transmission pipelines at one or more city gate stations. This gas is metered in order to pay delivery charge and for determining natural gas send out to customers. Send out covers both sales and transportation deliveries. LDCs report this information annually to EIA. There are approximately 1,200 LDCs. The challenge to this approach is that LDCs do not account for all deliveries of gas in the economy, only about 60%. The remaining amount is delivered by transmission pipelines to large end users like petrochemical plants, large industrial users, and power plants.

  Require the large end users who are not behind LDC city gate stations to report their natural gas use under the part of the rule that covers large stationary sources. Virtually all of the large customers not served by LDCs would be covered under the stationary source rule.

Most of the industry-generated data used for commercial operations are in terms of heat content. Natural gas is priced per million Btu (MMBtu). The EIA forms require volumetric data (cubic feet) with heat content (Btus) listed as a separate item. The industry has gone over to buying and selling gas on a Btu basis; gas prices are quoted in Btus. Thus data can be reported in Btus but the constituents contributing to the Btus are not measured or reported.

One effect of pricing gas by heat content is that often some of the higher hydrocarbons are left in the gas stream to raise the Btu content and get the higher price. This is especially true when NGL prices are low relative to gas prices and in these cases, processors may divert ethane into the dry gas stream to increase the heat content and raise the value of the gas. High Btu content is a characteristic of LNG and in fact has been a major point of contention between importers, pipelines, and certain end users. At some LNG terminals, vaporized LNG is mixed with nitrogen to reduce the heating value to the range tolerated by the pipelines (typically between 950 and 1050 Btus per cubic foot.)

Any EPA monitoring system will have to either require a measure of the constituents that contribute to the higher heat content or use a default conversion. We would expect that using default values would be preferred since natural gas delivered through pipelines is reasonably homogenous. Sources of guidance on developing reporter-specific emission factors include the American Gas Association (AGA) Gas Measurement Committee Report on heating value and the American Society for Testing and Materials (ASTM) procedures in ASTM D-1945-03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, for compositional analysis.

4.2 Reporting Options for NGLs and Coverage Gaps

The only reporting option for NGLs is at the natural gas processing plant. There are approximately 566 gas processing plants that strip NGLs from the raw gas stream and sell NGLs. Processors report their NGL production to EIA.

The major challenge with NGL reporting is that most of the NGLs are for non-energy uses such as feedstocks to petrochemical production or gasoline. The individual processor-reporters however do not record how the NGLs are used. Facility operators may sell NGLs to wholesalers or directly to petrochemical plants, where depending on prices the NGLs may be used as feedstock or burned as a fuel.

The current reporting of NGL sales to EIA is on a volumetric basis. There is no reporting currently of heat content or other constituents. Any EPA monitoring system will have to either require a measure of the constituents that contribute to the higher heat content or use a default conversion. Sources of guidance on heat content and compositional analysis include the Gas Processors Association Technical Standards Manual for NGL heating value and the ASTM report D-2597-94 “Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography”.

4.3 Quality Assurance and Control

EPA has very little information on the quality of data reported on the various forms. There is the presumption that mandatory reports with sanctions for not reporting will be accurate as far as the reporting requirements go. One of the points made at several places in this report is that as a matter of normal business operations, gas is tracked throughout the industry and along the natural gas value chain. NGLs also are metered and tracked. A distinction should be drawn between gas that is metered for purposes of billing and that which is metered for operational purposes. In a number of instances, operational data are aggregated for reporting purposes without the reconciliation that is necessary to generate "billing quality" data.

Billing quality data refers to volumes reported in order to bill customers or to pay royalty interests or to pay taxes. Billing quality data has undergone a reconciliation process that is deemed sufficient for the data to be used for invoices. Billing data are audited. Billing quality data are the "gold standard" of the data generated in the gas industry. Since gas is the product, the data used in its buying, selling, and custody transfers are deemed accurate. The same is true for NGLs. Billing quality data exist in a number of places where the title is exchanged and where taxes and royalties are calculated. These fall into three categories:

- Producers generate detailed accurate data on the output of wells in order to make royalty payments to the various working interests in the wells; royalty payments to land-owners (including the federal government); and severance taxes to states. These data are rolled up and reported to the states by well operators. (Well operators are the producers. There may be other working interest owners in a given well.) While there are about 450,000 wells in the U.S., the largest 20 operators control about 60% of the production; the largest 460 operators control about 94% of the production. So while the number of wells is large, the number of reporters is not so large; and the number of states collecting the data is even smaller.

- Title transfer points for the gas commodity into and out of the transmission pipelines are metered and reconciled for billing purposes. This includes receipt transfer from intrastate pipelines, where gas can be sold either on a "bundled" with the transportation service or unbundled, as well as interstate pipelines where gas is transported exclusively on an unbundled basis. It also includes the delivery points where gas is delivered to a LDC, end user or another transmission pipeline. To EPA's knowledge these data are nowhere reported in any except the most aggregate fashion. But billing quality data are generated and exist. That said, it begs the question of double counting, which is addressed above.

- LDCs meter and bill end users for the consumption of gas. LDCs also report their sales, deliveries of transported gas, and associated revenues to state regulators. Non-regulated LDCs (municipally owned or customer owned systems) would report the data to their local government or as part of their annual reports. Missing from this set of data reporters would be direct end-users who do not sit behind a LDC city gate. These data would be more difficult to acquire.

- Processors meter and bill for the NGLs they deliver to pipelines, trucks, or rail cars. While the processor may not know where the product will be going, as for example where pipes connect a processing plant directly to a refinery or petrochemical facility, the processor does not know how much of the product will be used for feedstock or fuel.

For more information related to data quality issues we have included a discussion of contracting along the natural gas value chain as Attachment A and for NGLs as Attachment B.

Attachment A

Contracting Along the Natural Gas Industry Value Chain Simplified

This paper provides a simplified overview of transaction and contracting practices in the natural gas industry with specific reference to how costs are built up and passed along to ultimate consumers.

Pricing Concepts

Wholesale commodity natural gas prices are not regulated. Prices are determined by market supply and demand. Almost all contracts involving the sale of gas set the price in reference to open market gas price indices, the most important being the New York Mercantile Exchange (NYMEX) Henry Hub index.[10] There are about 60 regional trading locations or "hubs" around the U.S. and Canada for which prices are published. The prices reported are "daily" (the price for a single next day's gas flow) or "monthly" (the price for a steady daily volume of gas to be delivered over the coming month and settled during "bid-week," the last 4 working days before the coming month). These published hub prices have become the standard price "indices" used throughout the North American market.

Prices for gas sales at these hubs are reported in several industry publications along with Henry Hub NYMEX Futures prices in the major newspapers.[11] The difference between prices at the various hubs is referred to as the "basis." The basis reflects the market value of transporting gas from one location to another over the pipeline transmission network ***and*** the local market supply and demand conditions.

> *An Example*: The average basis between Henry Hub and the Transco New York hub is about $0.50/MMBtu, which is about 75% of the average of the regulated firm transportation costs to transport gas from south Louisiana to the New York. In winter, as demand in New York increases, the basis can rise to $2.00/MMBtu or more. Actual transportation costs are largely the same but demand drives up the price in New York, and the basis increases.
>
> *Another Example*: The average basis between Henry Hub and Chicago is about $0.20/MMBtu. This is less than the cost of transportation between the south Louisiana and Chicago. The gas setting the price in Chicago comes from Alberta, thus at the margin, little gas is bought in the Gulf for sale into the Chicago market; to do so one would lose money. This basis can expand if more

[10] A hub is a location where a number of pipelines meet and there is sufficient supply and take-away capacity to attract buyers and sellers to create a liquid market for gas. Hubs also can be the outlets of processing plants or a broader "pooling regions" where a lot of production is interconnected with pipelines. Henry Hub, in south Louisiana has both a processing plant and a header pipeline that connects 8 major pipeline systems to each other.

[11] FERC has conducted numerous work shops and identified the procedures to be used in collection and publication of index prices that can be used in FERC jurisdictional transactions.

supply were to drive the price down at Henry Hub and make it profitable to pay transportation costs to move gas to Chicago. (Alternatively, less gas from Canada could drive up the price in Chicago.)

Prices throughout the system are set in bilateral trades in reference to nearby liquid hubs. Gas sold at the outlet of a processing plant close to, say, Carthage Hub (east Texas), will be priced in reference to that hub, plus or minus a transportation charge, depending on whether the plant is downstream or upstream from the hub. Gas prices across the North American market are thusly related to each other. A price movement in one location will get signaled to other locations and the market adjusts. This works well except where pipeline constraints effectively isolate a geographic market and reduce the price signals between markets. Something like this happened in 2007 when gas in the Rockies plunged to below $1.00/MMBtu due to high local production and bottlenecks in the pipelines leaving the region. More gas was being produced than could leave the basin. The resulting basis between the Rockies and Chicago expanded to over $4.00/MMBtu – a so-called "basis blow-out," as the price of gas in the Rockies collapsed. Basis blow outs can be price signals that additional pipeline capacity will be built. (The new Rockies Express Pipeline that will carry gas from the Rockies to the east, including Chicago, is in construction.)

Gas can be bought in a daily, spot market or may be bought under contracts with terms of a month or several months to a year or more. Common indexing will specify either daily price calculation or first of the month price determination though there can be other forms of tying gas prices to public indices. There are some contracts tied to a market basket of fuels or regional power prices. Firm fixed pricing is rare.

Wholesale hub gas prices thus set are the foundation for gas pricing in all contracts. End users will pay a hub price *plus* transportation costs to their facilities. Producers will receive a hub price *minus* the costs of transportation to the hub from their wells (producers refer to this as the "netback")[12].

Interstate pipeline transportation prices are regulated by the FERC. The interstate pipelines do not own the gas but are paid by shippers to transport the gas, like a railroad or trucking company. Transportation tariffs have three components.

- The reservation rate or capacity charge is a fixed monthly amount for reserving the capacity on the pipeline. A typical charge will be something like $8.00/MMBtu/month of capacity for the term of the contract which typically runs for several years (up to 20 or more). A shipper with 10,000 MMBtu of reserved capacity will pay $80,000 per month in capacity charges. This would average to about $0.26/MMBtu if the shipper used all his capacity every day of the month. In spite of the fact that capacity charges are sunk costs, load factor has a large impact on a shipper's cost on a per unit basis. Were he to use only half the capacity his average capacity cost would increase to $0.52/MMBtu.

[12] This is not to say that all gas is bought and sold at the index prices. Some longer term agreements have determined prices based on other formulas, but the volume of these transactions is considerably smaller than index based transactions.

- The commodity rate is a unit charge for gas actually shipped where the total varies with the shipped volumes. Commodity rates are something like $0.02/MMBtu. If a shipper were to transport 10,000 MMBtu/day, his commodity costs would be about $6,080 for the month.

- The third component is the fuel charge; pipelines take a percent of the shippers' gas to operate the compressors. A typical percent may be 3 to 4%, but it obviously depends on the distance transported and design of the pipeline. So the shipper has to buy an extra amount of gas to cover the fuel. He buys this at the source his supply. If the source is Waha Hub (West Texas) where the price is $6.00/MMBtu, the shipper would calculate his transportation fuel cost as 4% of $6.00 or $0.24/MMBtu of gas shipped

Total unit cost for transporting gas using these examples would be $0.52/MMBtu if the shipper were using his capacity fully.

Interstate pipelines can discount rates down to the variable costs of transportation, that is, the commodity and fuel charges. Shippers who do not use all their capacity can resell it in the secondary market. In this market, the going rate will more closely track the current basis differential between hubs.

Interstate transportation tariffs also contain a fourth component, small surcharges to cover the cost of regulation.[13] Also pipeline tariffs can contain other cost trackers to cover some specific event-related cost associated with a particular pipeline.

<u>Intrastate pipelines'</u> rates are not regulated. Prices for transportation are negotiated. Intrastate pipelines also offer "bundled" gas service, where they may own the gas and bundle it with the transportation cost to a buyer.

<u>Local distribution companies</u> buy commodity gas which they ship over their contracted capacity on the pipelines, and resell on a bundled basis to customers. The bills of LDC customers are priced in therms (100,000 Btus or 1/10th of a MMBtu) and typically have three basic components:

A flat system charge, say $9.00 per month, billed each customer.

A distribution charge related to the amount of gas consumed within certain bands, as for example, $0.46/therm for the first 25 therms and $0.26/therm for the next 55 therms.

A natural gas supply service based on the cost of gas for the month – essentially a pass-through of the gas costs. If a customer consumed 80 therms in a month and the gas costs were $11.00/MMBtu delivered, the bill would have a $1.10/therm component for the 80 therms consumed.

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[13] Historically such surcharges have also been used to collect some industry supported research such as the Gas Research Institute. However, this approach was rejected by industry because parties were concerned that the industry structure created recovery risk and absorption of the charge by market participants.

LDCs also transport gas on behalf of customers, in which case the gas supply component of the bill will not be included since the customer is paying another party for the gas delivered to the city gate. Under customer choice programs where various suppliers provide gas to residential customers, the LDC may provide the billing for the commodity on the same bill.

Marketers are merchants purchase gas at wholesale from producers or other marketers and package the gas with pipeline, storage, and financial services to create gas supplies tailored to customers' needs. These may include seasonal patterns of delivery, structured pricing provisions, "put" and "call" arrangements, among others. These are usually bundled services (the delivered price of gas includes everything) although they may have separate components. Supply contracts with marketers run for any period of time – day-to-day, monthly, annual or multi year.

Key Contract Terms

Gas commodity contracts typically have the following major components

Quantity. Specified as maximum daily quantity (MDQ).

Term. Period in days, months of delivery over which MDQ is delivered.

Supply obligation. Whether the supply is firm or interruptible or "best efforts."

Take obligation. Sets a minimum purchase requirement.

Price. Usually specified in reference to a hub price, and frequency of resetting (e.g., daily, monthly). Other costs may be added for additional services, mark-up.

Delivery or Receipt Point. Where the ownership transfer takes place and which depends on whose transportation capacity is to be used. If the buyer holds the pipeline capacity then the transfer will be closer to the seller and the price will not include transportation costs. If the seller holds the pipeline capacity, then the price will include a delivery charge to recoup the transportation costs.

Nominating and scheduling protocols. Governs communications between the parties and pipelines for scheduling deliveries.

Balancing responsibilities. Who is responsible for paying pipeline imbalance charges when they occur.

Responsibility for taxes/regulatory obligations. Specifies who is responsible for any taxes and how any regulatory obligations imposed subsequent to the sale will be resolved. Can lead to termination.

Default, *force majeure*. Sets procedures for what to do in cases of default and interruptions not the cause of the parties.

Pricing terms may include trackers for specific purposes. An example may be where a tracking account may be set up for when market prices exceed a threshold and the amounts in excess of the threshold will not be charged to the buyer but placed in a tracking account and charged later, inclusive of carrying costs. Transportation costs can be treated as trackers and passed along to the buyer.

Interstate pipeline transportation contracts or “service agreements” for firm service typically are long-term, running for several years and traditionally have been for 20 year terms. Pipelines do execute short term contracts, especially for interruptible services. The pricing and service obligations in these contracts always refer to a public tariff. The tariff has three components: a schedule of rates; a set of conditions of service defining specific services a shipper contracts for, as well; and the pipeline’s general terms and conditions, which apply across each of the services. For a given rate service, for example, the pipeline tariff will spell out the terms and conditions of the service, which may be for firm or interruptible transportation, or storage, or “no-notice” service, or some other type of service the pipeline provides. Each service will have a rate schedule (prices) associated with it. The pipeline’s general terms and conditions will govern the general rules applicable to all transporters, such as quality of gas.

Pipeline rates are set in administrative hearings before the FERC in which shippers and interested parties can contest the proposed rates. Producers often will argue for rates and rate designs that reduce the variable costs of transportation in order to increase the price they receive at the wellhead (their netback). Pipeline rates approved by FERC specify a maximum lawful rate and a minimum rate that is designed to reflect the variable cost of transportation. Pipelines will discount the rates to meet competition from alternative fuels or “gas on gas” competition, which is competition between gas supply from different sources that is transported on different pipelines.

Intrastate pipelines and gathering pipelines, not being under economic regulation by FERC, may not have posted tariffs.[14] All transportation deals are negotiated between the parties.

LDC rates are reviewed and must be approved by state commissions in rate proceedings. In some jurisdictions, these proceedings are required periodically. In others, the proceedings occur only when the LDC or the Commission requests a “rate case,” or another stakeholder can demonstrate that it is necessary. Many commissions have annual gas cost approval processes to monitor prices where LDCs pass through commodity and interstate pipeline transportation costs. In these cases the commissions will review the purchasing practices of the LDCs for prudence, but not the commodity price of gas, per se. The commissions must approve the distribution rates that can be charged by the LDCs.

Marketer contracts look like the commodity contracts described above. They may be more complicated where the marketers provide additional value-added services.

The Natural Gas Value Chain

The table below represents the major steps and relative values of gas along the pathway from the producer to the consumer. It presents a mixture of contract based costs and market based pricing. Our example could be that of a northeastern manufacturer who buys gas at a hub-based index and a producer who is selling into a hub-based index. The market clears at the hub.

[14] The degree of economic regulations for intrastate facilities differs significantly from state to state. They range from virtually no economic regulation to full blown rate proceedings.

Stage	Price ($/MMBtu)	Description
Price of gas at the end user's plant	**$8.60**	Final price to the plant
LDC distribution charges	+$2.00	LDC distribution charges are based on the allocation of system-wide costs to this industrial customer class that buys its own gas. Residential customers would see a larger mark-up.
City gate price	**$6.60**	Establishes the gas price for all system customers. We assume here it is the same as the manufacturer's gas price.
Pipeline transportation from hub to city gate	+$0.60	Pipeline transport costs from the producing region to the consuming region.
Hub price	**$6.00**	The market clearing price at the liquid hub.
Pipeline transportation to the hub.	-$0.25	Pipeline transport costs in the producing region.
Processing plant outlet into the pipeline	-$0.05	Processors usually take a share of the NGLs as payment in kind.
Gathering system delivery to processing plant	-$0.20	Negotiated rate determined by competitive market in the region.
Wellhead	**$5.50**	Netback to producer

The netback to the producer is the clearing price of gas at the hub market less all the costs of getting to that market. The clearing price at the hub will be influenced by the downstream demand for gas and demand elasticities including other competing sources of gas or fuels, as well as gas supply availability into the hub.

Attachment B

How NGL Markets Work

In order to understand how each NGL product travels from producers to final consumers, this section explores the NGL marketplace.

Processing

The extraction of NGLs from wet gas occurs for several reasons. First, it is necessary to extract NGLs from wet gas to meet the rules and standards of transporting natural gas through pipelines. Pipelines only accept "dry" gas. Although liquid hydrocarbons can increase the Btu content of natural gas, they can cause liquid-formation, causing deterioration and even rupture of the pipelines. Second, there are active markets for NGL products. The NGL market in the United States is large, with over 44 billion gallons of NGLs sold annually.

Entities that separate NGLs wet gas into dry gas and NGL products include (1) vertically-integrated processors who own the gas being processed, (2) fully integrated oil companies (e.g., ExxonMobil, ConocoPhillips), (3) independent processors, (4) intra- and interstate pipelines that store and transport mixed NGLs. Price, service, and location are factors that determine the market share that each competitor occupies in the gas processing market.[15]

The most common type of contract is the **keep-whole contract**. Under this arrangement, the processor becomes owner of the extracted mixed NGLs. It realizes profit when it sells and delivers NGL products to its customers. "Equity NGL production" is the term used to describe any mixed NGLs to which the processor becomes entitled after extraction. In return, the producer receives either dry natural gas at the processor's tailgate or payment equivalent to the energy value of mixed NGLs extracted.

Keep-whole contracts are profitable for the processor as long as the prices for NGL products exceed the cost of removing them from the gas stream. When they do not, processing plants may be shut down or the NGLs may be left in the gas stream (up to the limits imposed by the pipeline). Therefore, the industry has developed alternatives on keep-whole contracts. [16]

- Margin-band. The processor retains ownership of mixed NGLs, and sells fractionated NGL products to customers using bi-lateral sales agreements. In return, the producer receives a negotiated form of payment based on the energy

[15] Enterprise Products Partners, L.P. 2007 10-K. pp. 4, 5. http://library.corporate-ir.net/library/80/805/80547/items/301027/EPD%202007%2010-K%20FINAL.pdf

[16] The following descriptions unless otherwise noted are taken from EIA. "Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market." Jan. 2006. http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf

value of mixed NGLs, minus the cost of natural gas shrinkage and plant fuel. Producer and processor establish price floor or ceiling, depending on the price of NGL products in order to provide acceptable returns to both parties.

- Percent-of-liquids. The processor takes a portion of the extracted mixed NGLs as payment, and realizes profit from the sale of NGL products. The producer either owns the remaining portion of mixed NGLs, or receives a negotiated form of payment that is equivalent to the energy value of the remaining mixed NGLs. The producer also pays for all costs associated with natural gas processing.

- Percent-of-proceeds. In this agreement, the extracted NGL products belong to the producer. The processor shares in the revenue generated from sales of NGL products. It can also charge the producer fees for gas processing and delivery of mixed NGLs and NGL products.[17]

- Percent-of-Index. The processor purchases wet gas at a discount to a chosen gas-price index. It then sells NGL products to end users at market price, and dry natural gas at the previously specified gas-price index[18].

- Fee-based. The producer retains ownership of NGL products and any revenue realized from their sale. It pays a negotiated fee (cents per gallon) to the processor, based on the volume of gas to be processed. The producer is also responsible for all fuel costs, which could be adjusted based on the market price of natural gas used in gas processing.

- Hybrid. Hybrid contracts operate as monthly percent-of-liquids arrangements. Depending on the price of NGL products during that month, the producer has the option of converting the hybrid agreement to a fee-based or keep-whole contract. This arrangement protects the producer during periods of high volatility in the NGL market. Processors also have some level of protection against losses when the economic value of NGL products is below the cost of gas processing. For instance, under the percent-of-liquids, hybrid, and keep-whole contracts, processors have a right but not the obligation to process natural gas for producers.[19]

The point to note here is that processors may produce the NGLs but they often do not own the products being sold or transported from the processing site. This will complicate any monitoring system aimed at distinguishing between fuel and non-fuel uses of NGLs.

Fractionation, transportation, and delivery

Fractionation is the separation of a mixture of NGLs into the marketable products. Fractionation occurs at the processing plants or at specialized fractionation facilities. Many processors are located in regions where there are no near-by markets for individual NGL products, hence they do not fractionate the NGL stream produced from

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[17] Enterprise Products Partners
[18] Penn Virginia Resource Partners. Form 10_K. Feb. 29, 2008. p. 3. http://216.139.227.101/interactive/pvg2007/pf/page_008.pdf
[19] Enterprise Products Partners

wet gas. Instead they ship the mixed NGLs to another locale nearer the markets where fractionation will take place. Mixed NGLs are mostly shipped by pipeline, but also can be transported by railcars, barges, and trucks. Major transporters of mixed-NGLs are pipelines owned by oil, petrochemical, and gas companies and barge, rail, and truck fleet operations. Transportation fees, the destination of mixed NGLs, and dependability of the transporters are factors that drive processors' choices about transporting their mixed NGLs.

Sometimes, mixed NGLs are sent to underground storage facilities, typically salt dome storage.[20] Processors will store rather than sell products to meet future obligations or to manage risk around volatile NGL prices. From storage, the mixed NGLs will eventually go to a fractionation facility.[21] Fractionation facilities can be operated by independent operators or as an adjunct to the processing operations. Large NGL product producers in the United States such as ConocoPhillips and Enterprise Products Partners follow an integrated business model in which the fractionation facility is affiliated with the processor.

Once separated, individual NGL products (ethane, propane, butane, and pentanes plus) are sold to petrochemical plants, oil refineries, and wholesalers under bilateral sales agreements with the processor or independent fractionation facility. The buyers and the commercial department at the processing company stipulate terms of the sales contract, while the marketing department of the processing company determines from which fractionation or storage facility NGL products should be sent to the buyer. The marketing sales department of processors also can purchase NGL products on the spot market and enter into futures contracts to balance contracts, hedge, and manage positions.

The bilateral sales agreements typically specify the price for the delivered NGL product, quantity purchased, duration of the contract, and such other terms as may be relevant to delivery conditions, or other conditions. Prices are usually set at prevailing market quotations and will vary month to month and even daily.

In general, the chosen mode of transportation for NGL products is as dependent on their end uses as it is on other factors such as destination and cost. For instance, the use of ethane and propane as feedstock allows these two NGL products to travel through pipelines in batch mode to petrochemical plants. Because of ethane's high vapor pressure, it can only be transported through pipelines.[22] Propane for both fuel and non fuel applications moves over pipelines; but for fuel uses also moves over rail cars, and then trucks to end users at the retail level.[23] The Dixie pipeline that extends from Grangeville, Louisiana to Hattiesburg, Mississippi is one example.[24]

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[20] Salt dome storage facilities are hollowed out salt formations deep underground. The Strategic Petroleum Reserve is in a complex of salt domes. Salt domes also are used to store natural gas.

[21] Telephone conversation with Enterprise Products Partners on Dec. 17-18, 2008.

[22] Freedenthal, Carol. "Natural Gas liquids Pipelines Play Major Role In Marketing Products." Pipeline and Gas Journal. Sep. 2000. http://findarticles.com/p/articles/mi_m3251/is_/ai_n25030734

[23] Telephone conversation with Mark Sutton, President, Gas Processors Association, Dec. 18, 2008.

[24] Dixie Pipeline Company. Local Pipeline Tariff containing rates, rules, and regulations of ethane transported by pipeline from Louisiana to Mississippi. July 6, 2008. http://www.dixiepipeline.com/pdf/DPL_FERC_91.pdf

Butane and pentanes-plus used for gasoline blending would travel through pipelines with gasoline and diesel fuels. Because petroleum products with similar properties or the same intended use travel in batch through refined-petroleum-products pipelines, propane can also travel with butane in pipelines that carry pentanes-plus, gasoline, and diesel fuels. If there is a need to separate mixed hydrocarbons at the interface, it would go through a fractionation facility located at the pipeline's delivery point.[25]

The United States exports small amounts of NGL products. These are mostly local sales into Canada and Mexico.

Large storage facilities for NGL products are located at major market hubs where NGLs are traded. The most active hub for purchasing NGL products in North America is Mont Belvieu, Texas, followed by Conway, Kansas and Edmonton / Fort Saskatchewan, Alberta.[26] (Market hubs are where pipelines, storage, and rail/truck facilities come together to effect physical transfers of products.) Wholesale prices are quoted at these hubs. There is a national wholesale price for propane quoted at Mont Belvieu, where the New York Mercantile Exchange (NYMEX) propane futures market contract is located.

Wholesalers that buy propane and butane from gas processors or fractionation plants then resell the product to distribution companies who sell the product at retail to individual end users. Some of the largest distributors have their own wholesale operations and storage facilities (e.g., Suburban Propane, AmeriGas).[27]

[25] Telephone conversation with TEPPCO, which owns the TE Products Pipeline on Dec. 22, 2008.
[26] Telephone conversation with Enterprise Products Partners.
[27] Kay Lusnak. NGL Supply Inc. 918-481-1119. Dec. 18, 2008.