NETL Life Cycle Inventory Data
Process Documentation File

Process Name: Extraction of natural gas (NG) from Barnett Shale

Reference Flow: 1 kg of natural gas from Barnett Shale

Brief Description: Data for the extraction of natural gas from Barnett Shale.

Section I: Meta Data

Geographical Coverage: US **Region:** N/A

Year Data Best Represents: 2010

Process Type: Extraction Process (EP)

Process Scope: Cradle-to-Gate (CG)

Allocation Applied: No

Completeness: Individual Relevant Flows Captured

Flows Aggregated in Data Set:

☒ Process ☒ Energy Use ☐ Energy P&D ☐ Material P&D

Relevant Output Flows Included in Data Set:

Releases to Air:	☒ Greenhouse Gases	☒ Criteria Air Pollutants	☒ Other
Releases to Water:	☒ Inorganic Emissions	☒ Organic Emissions	☐ Other
Water Usage:	☒ Water Consumption	☒ Water Demand (throughput)	
Releases to Soil:	☐ Inorganic Releases	☐ Organic Releases	☐ Other

Adjustable Process Parameters:

Recip_userate — *Fraction of well life during which compression is necessary for gas recovery.*

NG_flared — *Natural gas that is flared per kg of natural gas produced*

Tracked Input Flows:

None.

Tracked Output Flows:

Natural Gas from Barnett Shale — *Natural gas extracted from Barnett Shale*

Section II: Process Description

Associated Documentation

This unit process is composed of this document and the data sheet (DS) *DS_Stage1_O_BarnettShale_NG_Extraction_2010.01.xls*, which provides additional details regarding relevant calculations, data quality, and references.

Goal and Scope

The scope of this unit process encompasses the energy inputs and material outputs for the extraction of natural gas from Barnett Shale. The unit process is based on the reference flow of 1 kg of extracted natural gas. The relevant flows of this unit process are described below and shown in **Figure 1.**

The inputs to this unit process are natural gas, ground water, and surface water. These three inputs are natural resources and thus enter the boundary of this unit process with no upstream environmental burdens. The output of this unit process is dehydrated natural gas that is suitable for pipeline transport and subsequent processing steps such as sweetening or, in the case of imported natural gas, liquefaction. In addition to resource inputs and outputs that are used by downstream unit processes, this unit process also accounts for environmental emissions to air and water.

Boundary and Description

Natural gas is dispersed throughout the Barnett Shale formation in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracing). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracing uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale reservoir and facilitating the flow of natural gas. Natural gas from Barnett Shale accounts for approximately 6.6 percent of the U.S. natural gas production. This production share is based on the new natural gas pipeline capacity that was added solely for natural gas production from Barnett Shale; approximately 11 percent of new pipeline capacity in 2008 (4.8 billion cubic feet per day) was installed for natural gas from Barnett Shale (EIA, 2009b). The average daily output of a natural gas well in the Barnett Shale is 1,000 cubic feet (Hayden and Pursell, 2006).

The key sub-systems for natural gas extraction include compression, dehydration, flaring, water use, and water quality. The data and assumptions for these sub-systems are described below.

Compression

Compressors are used at the natural gas wellhead to increase the gas pressure for pipeline distribution. The use of a compressor depends on the natural pressure at the wellhead, which varies from reservoir to reservoir and decreases with increasing well life.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMCF of natural gas; a three-stage compressor with an inlet pressure of zero psig and an outlet pressure of 800 psig has a power requirement of 282 horsepower per MMCF of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/scf and converting to SI units gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas and 2.65E-04 MWh per kg of natural gas, respectively. These energy intensities represent the required output of compressors per unit of natural gas that is compressed.

A reciprocating compressor uses pistons for gas compression. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/scf, a natural gas density of 0.042 lb/scf, and converting to SI units translates to 217 kg of natural gas per MWh of reciprocating compressor shaft energy. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The air emissions from the combustion of natural gas in reciprocating compressors are based on EPA's AP-42 emission factors for fuel combustion in stationary equipment. These emission factors include greenhouse gases, criteria pollutants, and other air emissions specific to reciprocating compressors (EPA, 1995).

A centrifugal compressor uses rotary motion in which an inlet gas stream is received at the hub of a set of rotating blades and propelled outward to produce a compressed gas stream. Centrifugal compressors are preferred for large-scale extraction operations because they are more efficient than reciprocating compressors. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. If the natural gas extraction site is near a source of electricity, it is financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the ERCOT grid, which is representative of electricity generation in Texas (the location of Barnett Shale).

Flaring

Flaring is an intermittent operation, necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. Based on a 98 percent flaring efficiency, the flaring of 1 kg of natural gas results in air emissions of 3.0 kg, 1.8E-02 kg, and 3.4E-05 kg of carbon dioxide, methane, and nitrous oxide, respectively (API, 2009). This analysis assumes that, in comparison to the other activities of natural gas extraction, the flaring emission of criteria air pollutants and other air emissions of concern are insignificant.

The flaring rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Flaring rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, flaring rates have been parameterized in the model to allow uncertainty analysis. However, each natural gas extraction process of this analysis includes a default flaring rate that is based on a report by the U.S. Government Accountability Office (2004). The flaring rate is 0.30 percent for gas from Barnett Shale.

Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel.

A reboiler is used to heat the fluid in the stripper column; due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMCF. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMCF of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 8.0 Btu/kg of dehydrated natural gas. Assuming that the reboiler is fueled by natural gas, this translates to 1.5E-04 kg of natural gas combusted per kg of dehydrated natural gas.

The air emissions from the combustion of natural gas used by a dehydrator reboiler are based on EPA emission factors for natural gas combustion in industrial equipment (API, 2009).

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators can be used to capture methane emissions from glycol strippers; however, this analysis assumes that flash separators are not used, resulting in methane emissions. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 3.4E-04 kg of methane is released for every kilogram of natural gas that is dehydrated.

Water Use and Quality

Water is an input to hydrofracing (hydraulic fracturing), which is used for recovering natural gas from tight reservoirs such as Barnett Shale. Substantial water is produced during NG extraction of Barnett Shale (Texas Water Development Board, 2007). However, the water is of very poor quality, and is not discharged to the surface or to groundwater supply aquifers. Instead, it is injected to deep aquifers for disposal. Therefore, changes in water quality associated with produced water is considered negligible, since the deep aquifers are assumed to not mix with overlying aquifers. Flowback water is of generally better quality than produced water. Flowback water is fracing water that is subsequently released from the well during extraction. Volumes of flowback water are much smaller than produced water, but water quality of flowback water is still relatively poor. The water quality calculations assume that recycling that flowback water is treated before it is discharged (Shramko et al. 2009).

Figure 1: Unit Process Scope and Boundary

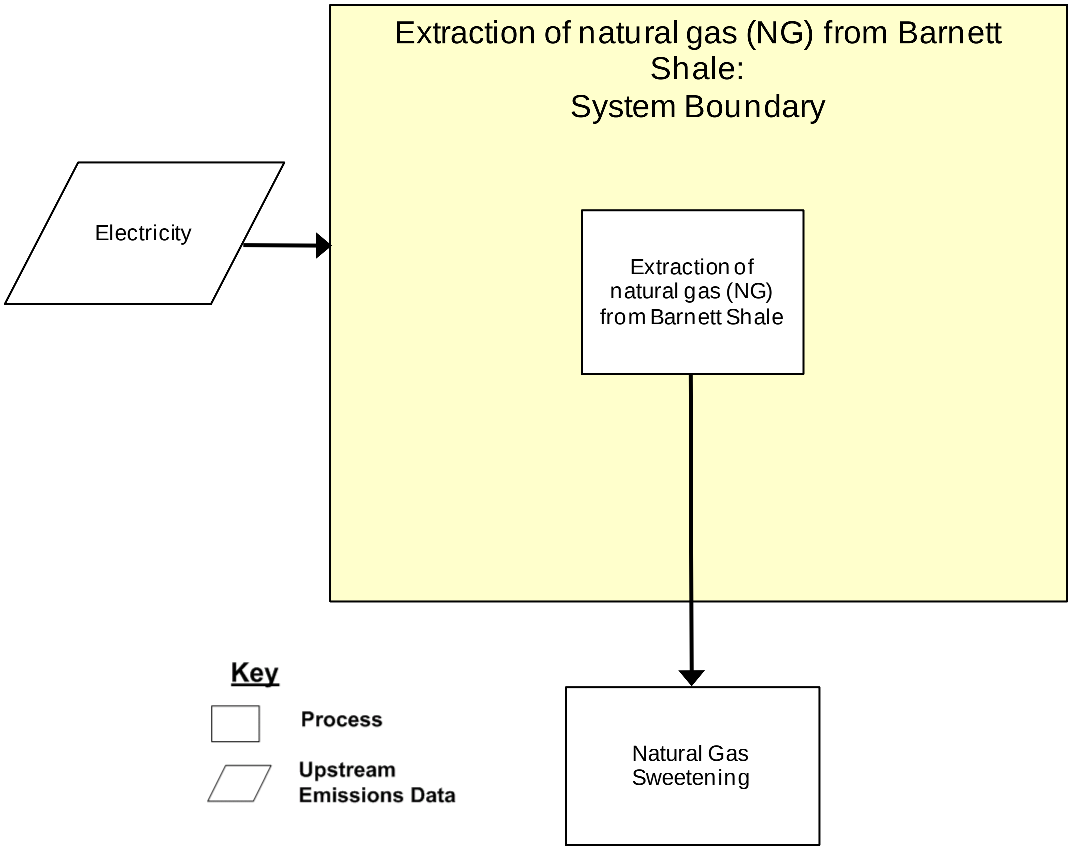

Table 1: Properties of Barnett Shale Gas Wells

Property	Value	Source
U.S. supply share	6.6%	EIA 2009
Well capacity	1,000 ft^3/day	Hayden and Pursell 2006
Well locations	Northern Texas	Hayden and Pursell 2006
Flaring rate	0.30%	US GAO 2004

Table 2: Unit Process Input and Output Flows

Flow Name*	Barnett Shale Gas Well	Units (Per Reference Flow)
Inputs		
Natural Gas from Barnett Shale	1.0321E+00	kg
Power [Electricity]	**4.6230E-05**	**kg**
Water (ground water) [Water]	8.2646E-01	kg
Water (surface water) [Water]	5.5097E-01	kg
Outputs		
Natural Gas from Barnett Shale	1.00	kg
Carbon dioxide [Inorganic emissions to air]	8.6346E-02	kg
Methane [Organic emissions to air (group VOC)]	1.2651E-03	kg
Nitrous oxide (laughing gas) [Inorganic emissions to air]	1.0481E-07	kg
Nitrogen oxides [Inorganic emissions to air]	2.8562E-03	kg
Sulphur dioxide [Inorganic emissions to air]	4.1163E-07	kg
Carbon monoxide [Inorganic emissions to air]	2.2192E-04	kg
NMVOC (unspecified) [Group NMVOC to air]	8.2606E-05	kg
Dust (PM10) [Particles to air]	6.9914E-06	kg
Water (wastewater) [Water]	3.4436E-01	kg
Calcium [Inorganic emissions to water]	2.0317E-04	kg
Chloride [Inorganic emissions to water]	2.0464E-03	kg
Iron [Inorganic emissions to water]	1.0933E-06	kg
Magnesium [Inorganic emissions to water]	2.5000E-05	kg
Silica [Inorganic emissions to water]	7.4037E-07	kg
Sulfate [Inorganic emissions to water]	7.9547E-06	kg
Total Dissolved Solids [Inorganic emissions to water]	3.7225E-03	kg

* **Bold face** clarifies that the value shown *does not* include upstream environmental flows. Upstream environmental flows were added during the modeling process using GaBi modeling software, as shown in Figure 2.

Embedded Unit Processes

None.

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Section III: Document Control Information

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