NETL Life Cycle Inventory Data
Process Documentation File

Process Name: Extraction of natural gas (NG) from a conventional onshore oil well with associated NG

Reference Flow: 1 kg of natural gas, conventional, onshore associated

Brief Description: Data for the extraction of natural gas from a conventional onshore petroleum well with associated natural gas.

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, Conventional, Onshore Oil Well — *Associated natural gas extracted from conventional, onshore oil well operations*

Section II: Process Description

Associated Documentation

This unit process is composed of this document and the data sheet (DS) *DS_Stage1_O_Conventional_Onshore_AssociatedNG_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 material outputs for the extraction of onshore natural gas from a conventional oil well that also produces natural gas (associated gas). 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

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated gas is similar to the extraction methods for conventional onshore gas. The use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Approximately 21.5 percent of U.S. natural gas production is from conventional onshore oil wells (EIA, 2009b). The majority of these wells are assumed to be in Texas and Louisiana (EIA, 2009). The production rates of onshore associated gas wells is highly variable, but an average associated gas well in the U.S. produces 59 barrels of oil and 61 thousand cubic feet of natural gas per day (EIA, 2009c).

The key sub-systems for natural gas extraction include compression, dehydration, flaring, oil/gas separation, 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.

This unit process assumes that reciprocating compressors are the dominant compression technology for conventional, onshore associated gas wells. 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).

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 0.21 percent for onshore conventional associated gas extraction.

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.

Oil and Gas Separation

Oil and gas separation is necessary when natural gas is co-extracted with crude oil and other liquids. It is accomplished with a series of separation vessels that reduce the pressure of the oil/gas mixture, causing the gas to come out of solution.

No data are available for the emissions from oil and gas separation, and the ratio of oil to gas in such operations is highly variable, which leads to issues of co-product allocation. To simplify this data limitation, this analysis assumes that the energy requirements for maintaining the pressure within each oil/gas separation stage are insignificant in comparison to the other compression operations required for oil and natural gas extraction. This analysis also assumes that methane is released at a rate of 0.1 percent and other hydrocarbons (VOCs) are released at a rate of 0.01 percent (these percentages are in terms of the mass of emission per mass of oil or natural gas produced). These percentages are based on professional judgment and are parameterized in the model to allow uncertainty analysis.

Water Use and Quality

Water is an output from conventional onshore oil and natural gas extraction. This unit process calculates produced water per kg of natural gas extracted based on total figures for annual US onshore oil/gas production (DOE 2006, EIA 2010, Argonne National Laboratory 2004). The total amount of produced water is then apportioned between annual U.S. natural gas and crude oil production (EIA 2010b), based on energy content, and only the fraction apportioned to natural gas production is considered further. Recycling of the produced water for secondary extraction (e.g., pumping water into wells to facilitate gas and oil extraction) is also considered.

Figure 1: Unit Process Scope and Boundary

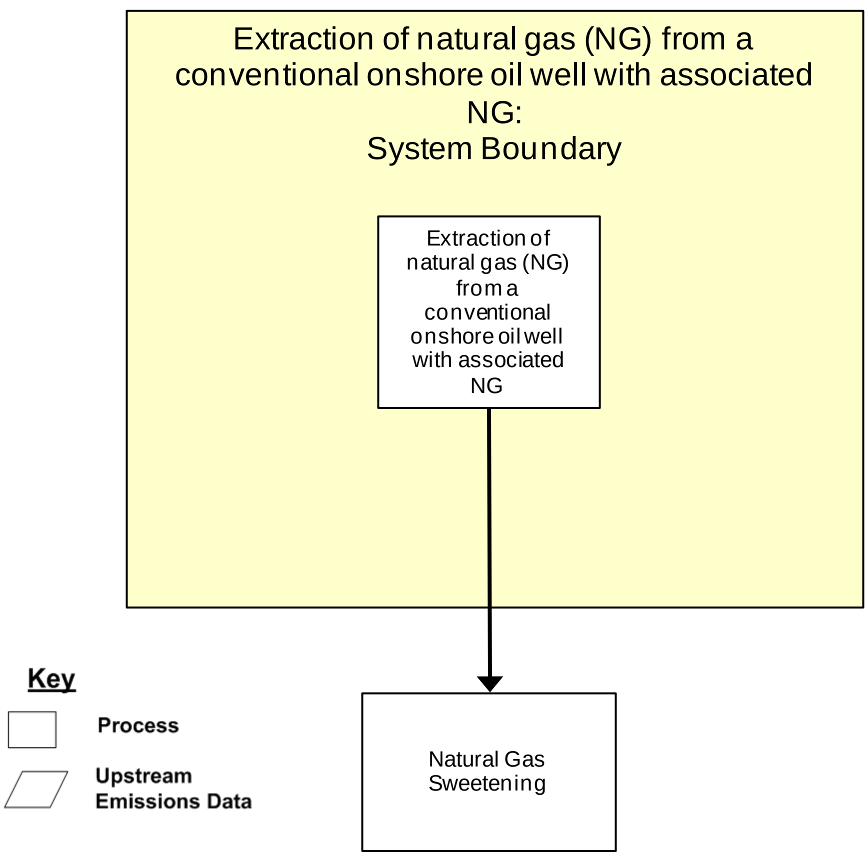

Table 1: Properties of Associated Natural Gas Wells

Property	Value	Source
U.S. supply share	21%	EIA 2009
Well capacity	Oil: 51 barrels/day; Gas: 61,000 ft^3/day	EIA 2009
Well locations	Texas and Louisiana	EIA 2009
Flaring rate	0.21%	US GAO 2004

Table 2: Unit Process Input and Output Flows

Flow Name*	Conventional onshore oil well with associated gas	Units (Per Reference Flow)
Inputs		
Natural Gas, Conventional, Onshore	1.042	kg
Water (ground water) [Water]	0.319	kg
Water (surface water) [Water]	0.319	kg
Outputs		
Natural Gas, Conventional, Onshore Oil Well	1.00	kg
Carbon dioxide [Inorganic emissions to air]	0.112	kg
Methane [Organic emissions to air (group VOC)]	2.53E-03	kg
Nitrous oxide (laughing gas) [Inorganic emissions to air]	1.66E-07	kg
Nitrogen oxides [Inorganic emissions to air]	3.62E-03	kg
Sulphur dioxide [Inorganic emissions to air]	5.21E-07	kg
Carbon monoxide [Inorganic emissions to air]	2.81E-04	kg
NMVOC (unspecified) [Group NMVOC to air]	2.05E-04	kg
Dust (PM10) [Particles to air]	8.86E-06	kg
Water (wastewater) [Water]	1.19	kg
Boron [Inorganic emissions to water]	1.90E-06	kg
Chloride [Inorganic emissions to water]	3.75E-04	kg
Total Dissolved Solids [Inorganic emissions to water]	3.91E-03	kg
Sulfates [Inorganic emissions to water]	1.51E-03	kg
Hydrocarbons [Organic emissions to water]	2.67E-05	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.

References

API (2009). Compendium of Greenhouse Gas Emissions for the Oil and Natural Gas Industry. API. Washington, DC. 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf (Accessed May 18, 2010)

Argonne National Laboratory (2004). A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane. National Energy Technology Laboratory.

DOE (1996). Buying an Energy-Efficient Electric Motor. Department of Energy, Industrial Technologies Program. 1996. http://www1.eere.energy.gov/industry/bestpractices/pdfs/mc-0382.pdf (Accessed May 18, 2010)\ EIA, 2007. Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996.

DOE (2006). Energy Demands on Water Resources; Report to Congress on the Interdependency of Energy and Water. U.S. Department of Energy. December, 2006.

EIA (2009a). Annual Energy Outlook 2009. Department of Energy, Energy Information Administration. http://www.eia.doe.gov/oiaf/aeo/index.html. DOE/EIA-0383(2009).

EIA (2009b). Natural Gas Annual 2007. Energy Information Administration, Office of Oil and Gas, Washington, DC. http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/nga07.pdf. DOE/EIA-0131(07).

EIA (2009c). United States Total 2008: Distribution of Wells by Production Rate Bracket. Energy Information Administration. 2009.

EIA (2010). Natural Gas Gross Withdrawals and Production. Available at: http://www.eia.doe.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm (Accessed June 30, 2010).

EIA (2010b). Petroleum Navigator: Crude Oil Production. Available at: http://www.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm (Accessed June 30, 2010)

EPA (1995). Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42. US EPA Office of Air Quality Planniing and Standards.

Research Triangle Park, North Carolina. 1995. http://www.epa.gov/ttnchie1/ap42 (Accessed May 18, 2010)

EPA (2006). Replacing Glycol Dehydrators with Desiccant Dehydrators, EPA, October 2006, Washington DC. http://www.epa.gov/gasstar/documents/ll_desde.pdf (Accessed June 1, 2010)

GE Oil and Gas (2005). Reciprocating Compressors. General Electric Company. Florence, Italy. 2005.

Houston Advanced Research Center (2006). Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities, H68 Final Report. Houston Advanced Research Center. Houston, Texas. 2006. http://www.utexas.edu/research/ceer/GHG/files/ConfCallSupp/H068FinalReport.pdf (Accessed May 18, 2010)

U.S. Government Accountability Office (2004). Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions. Washington, D.C. July 2004. http://www.gao.gov/new.items/d04809.pdf (Accessed June 18, 2010)

Section III: Document Control Information

Date Created: October 20, 2010

Point of Contact: Timothy Skone (NETL), Timothy.Skone@NETL.DOE.GOV

Revision History:

Original/no revisions

How to Cite This Document: This document should be cited as:

NETL (2010). *NETL Life Cycle Inventory Data – Unit Process: Extraction of natural gas (NG) from a conventional onshore oil well with Associated NG.* U.S. Department of Energy, National Energy Technology Laboratory. Last Updated: October 2010 (version 01). www.netl.doe.gov/energy-analyses (http://www.netl.doe.gov/energy-analyses)

Section IV: Disclaimer

B. Assumes any liability with this report as to its use, or damages resulting from the use of any information, apparatus, method, or process disclosed in this document.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by NETL. The views and opinions of the authors expressed herein do not necessarily state or reflect those of NETL.