# NETL Life Cycle Inventory Data
# Process Documentation File

| | |
|---|---|
| **Process Name:** | Natural Gas Sweetening, Amine Process Acid Gas Removal |
| **Reference Flow:** | 1 kg of Natural Gas, Sweetened |
| **Brief Description:** | This unit process quantifies the amount of natural gas, solvents, and water required for the sweetening of natural gas using an amine process for acid gas removal (AGR). |

## Section I: Meta Data

| | | | |
|---|---|---|---|
| **Geographical Coverage:** | United States | **Region:** | N/A |
| **Year Data Best Represents:** | 2010 | | |
| **Process Type:** | Extraction Process (EP) | | |
| **Process Scope:** | Gate-to-Gate Process (GG) | | |
| **Allocation Applied:** | No | | |
| **Completeness:** | All 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:**

N/A

**Tracked Input Flows:**

| | |
|---|---|
| Diethanolamine (DEA) [Organic intermediate products] | *Amine solvent used for acid gas removal* |

**Tracked Output Flows:**

| | |
|---|---|
| Natural Gas, Sweetened | *Reference flow* |
| Vented gas [Intermediate Product] | *Vented methane gas* |

## Section II: Process Description

### Associated Documentation

This unit process is composed of this document and the data sheet (DS) *DS_Stage1_O_NG_Sweetening_2010.02.xls*, which provides additional details regarding relevant calculations, data quality, and references.

### Goal and Scope

The scope of this unit process covers natural gas sweetening in support of natural gas extraction activities, as described in greater detail below. Natural gas sweetening, also termed acid gas removal (AGR), is comprised of amine based processes that are used to remove hydrogen sulfide ($H_2S$) from natural gas streams. This unit process considers relevant energy use, solvent use, water use, and airborne emissions associated with the natural gas sweetening process. Vented methane from the AGR process is considered within this unit process, but actual airborne emissions are accounted for within a separate unit process, DF_Stage1_O_NG_Flaring_2011.01.doc. The calculations presented for this unit process are based on the reference flow of 1 kg of natural gas, sweetened, as described below and shown in **Figure 1**.

This unit process is used under Life Cycle (LC) Stage #1 to assist in the extraction of natural gas from a variety of natural gas extraction profiles, including conventional onshore, conventional offshore, associated gas, Barnett Shale gas, Marcellus Shale gas, and coal bed methane. This unit process is combined with other relevant equipment for LC Stage #1 in a separate operations assembly process, DF_Stage1_O_Assembly_Natural_Gas _2011.01.doc. The assembly process quantifies the relevant flows and emissions associated with each portion of the natural gas extraction profile being modeled, in order to complete extraction and in-field processing of 1 kg of natural gas.

### Boundary and Description

Raw natural gas contains varying levels of $H_2S$, a toxic gas that reduces the heat content of natural gas and causes fouling in when combusted in equipment. The removal of $H_2S$ from natural gas is known as “sweetening”. Amine-based processes are the predominant technologies for the sweetening of natural gas. The H2S content of raw natural gas is highly variable, with concentrations ranging from 5.7E-05 kg of $H_2S$ per kg of natural gas to 0.16 kg of $H_2S$ per kg of natural gas. This analysis assumes an $H_2S$ concentration of 0.025 mol of $H_2S$ per kg of natural gas. This $H_2S$ concentration is ten times greater than the threshold $H_2S$ composition for NG -- an $H_2S$ concentration less than 0.0025 kg/mol does not require sweetening.

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of $H_2S$ removed from natural gas. Approximately 0.30 moles of $H_2S$ are removed per 1 mole of circulated amine solution (Polasek 2006), the reboiler duty is approximately 1,000 BTU per gallon of amine (Arnold 1999), and the reboiler has a thermal efficiency of 92%. The calculation of energy input per kilogram of natural gas product is shown by the following equation:

$$\frac{0.025\ mol\ H_2S}{kg\ NG\ product} * \frac{1\ mol\ amine}{0.30\ mol\ H_2S} * \frac{83\ g\ amine}{mol\ amine} * \frac{1\ lb\ amine}{454\ g\ amine} * \frac{1\ gal\ amine}{8\ lb\ amine} * \frac{1{,}000\ BTU\ reboiler\ duty}{gal\ amine} * \frac{1\ BTU\ energy\ input}{0.92\ BTU\ reboiler\ duty} = \frac{2.07\ BTU}{kg\ NG\ product}$$

The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing $H_2S$, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 2.8E-05 kg of methane per kg per natural gas sweetened (API 2009). The calculation of methane released by amine reboiler venting is shown by the following equation:

$$\frac{0.0185\ tonne\ CH_4}{10^6\ scf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1scf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG}$$

Raw natural gas contains naturally-occurring $CO_2$ that contributes to the acidity of natural gas. This $CO_2$ is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. The $CO_2$ composition of these non-hydrocarbon gases is 90 percent by volume (Little 2011), which translates to 649 billion cubic feet of $CO_2$. Using a $CO_2$ density of 0.116 lb/scf, total 2009 dry gas production of 20.5 trillion cubic feet (EIA 2011), and a natural gas density of 0.042 lb/scf (API 2009), the total mass of naturally-occurring $CO_2$ per unit production of natural gas is 0.0868 kg $CO_2$/kg NG. This analysis assumes that all of this naturally-occurring $CO_2$ is released during the sweetening of natural gas.

**Figure 1** provides an overview of the boundary of this unit process. As shown, extracted natural gas and diethanolamine (DEA) from upstream/modeled unit processes serve as inputs to the unit process. Within the unit process boundary, flows and emissions are calculated for methane venting, carbon dioxide venting, reboiler combustion emissions, solvent consumption, and water consumption. This unit process is then combined with other natural gas extraction operations unit processes in a downstream natural gas operations assembly unit process. Also, emissions associated with vented natural gas is quantified in a separate, downstream unit process.

**Figure 1: Unit Process Scope and Boundary**

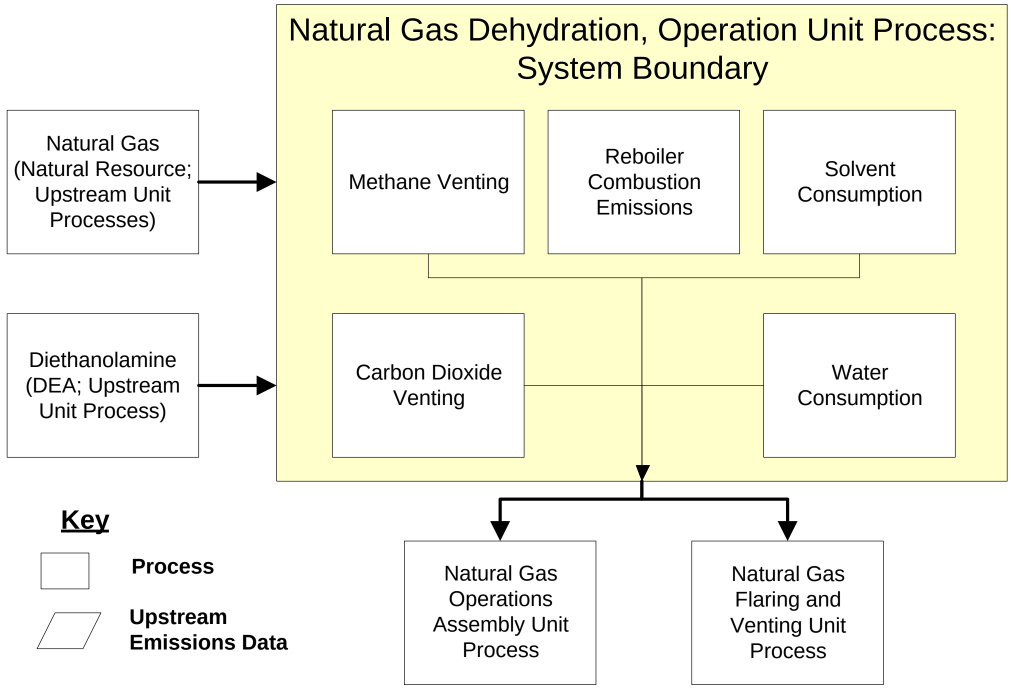


**Table 1** summarizes natural gas sweetening airborne emissions factors and energy inputs and outputs that are applied within this unit process. **Table 2** provides a summary of modeled input and output flows. Additional detail regarding input and output flows, including calculation methods, is contained in the associated DS.

## Table 1: Natural Gas Sweetening Air Emissions and Energy Use

| Air Emission Factors (per MMBtu of reboiler fuel) | | | |
|---|---|---|---|
| **Flow Name** | **Value** | **Units** | **Reference** |
| $CO_2$ | 2.86E+00 | kg $CO_2$/kg NG fuel | API 2009[1] |
| $N_2O$ | 1.56E-02 | kg $N_2O$/kg NG fuel | API 2009[2] |
| $CH_4$ (combustion) | 5.62E-02 | kg $CH_4$/kg NG fuel | API 2009[2] |
| NOx | 2.38E-03 | kg NOx/kg NG fuel | EPA 1995[3] |
| CO | 2.00E-03 | kg CO/kg NG fuel | EPA 1995[3] |
| Pb | 1.19E-08 | kg Pb/kg NG fuel | EPA 1995[3] |
| PM | 1.81E-04 | kg PM/kg NG fuel | EPA 1995[3] |
| $SO_2$ | 1.43E-05 | kg $SO_2$/kg NG fuel | EPA 1995[3] |
| NMVOC | 1.31E-04 | kg NMVOC/kg NG fuel | EPA 1995[3] |
| **Energy inputs and outputs** | | | |
| **Flow Name** | **Value** | **Units** | **Reference** |
| Reboiler energy[4] | 1.22E+00 | BTU/kg NG product | API 2009 |
| Reboiler fuel[5] | 2.26E-05 | kg NG fuel/kg NG product | calculated |
| **Air Emissions (per kg of natural gas produced)[6]** | | | |
| **Flow Name** | **Value** | **Units** | **Reference** |
| $CO_2$ (combustion) | 6.47E-05 | kg $CO_2$/kg NG product | calculated |
| $CO_2$ (venting) | 8.68E-02 | kg $CO_2$/kg NG product | calculated |
| $N_2O$ | 3.53E-07 | kg $N_2O$/kg NG product | calculated |
| $CH_4$ (combustion) | 1.27E-06 | kg $CH_4$/kg NG product | calculated |
| $CH_4$ (venting)[7] | 9.72E-04 | kg $CH_4$/kg NG product | API 2009 |
| NOx | 5.38E-08 | kg NOx/kg NG product | calculated |
| CO | 4.52E-08 | kg CO/kg NG product | calculated |
| Pb | 2.69E-13 | kg Pb/kg NG product | calculated |
| PM | 4.09E-09 | kg PM/kg NG product | calculated |
| $SO_2$ | 3.23E-10 | kg $SO_2$/kg NG product | calculated |
| NMVOC | 2.96E-09 | kg NMVOC/kg NG product | calculated |

[1] API combustion emissions for $CO_2$ were converted from the basis of tonnes/MMBTU to kg/NG fuel using the following factors: 1 tonne = 1,000 kg, 1 scf NG = 0.042 lb NG, and 1 kg = 2.205 lb.

[2] API combustion emissions for $N_2O$ and $CH_4$ were converted from the basis of lb/MMCF to kg/MMCF using the following factors: 1 scf NG = 0.042 lb NG, and 1 kg = 2.205 lb

[3] EPA combustion emissions for criteria air pollutants were converted from lb/MMCF to kg/kg NG using the following factors: 1 kg = 2.205 kg and 1 scf NG = 0.042 lb.

[4] The energy used for sweetening is based on a 0.025 mol of $H_2S$ per gram of raw natural gas, a molar loading of 0.30 mol $H_2S$ per mole of amine solution, a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92%.

[5] The reboiler energy input was converted to the mass of fuel input using a heating value of 1,027 BTU/scf NG.

[6] Combustion air emissions are the product of the emission factors per MMBTU of fuel and the use rate of reboiler fuel.

[7] The $CH_4$ venting factor assumes that the reboiler vent is not flared. API venting rates were converted from the basis of tonnes $CH_4$/MMCF to kg $CH_4$/kg NG product using the following factors: 1 tonne=1000 kg, 1 scf NG=0.042 lb NG, and 1 kg=2.205 lb

### Table 2: Unit Process Input and Output Flows

| Flow Name | Value | Units (Per Reference Flow) |
|---|---|---|
| **Inputs** | | |
| **Natural gas [intermediate product]** | **1.000995** | **kg** |
| **Diethanolamine (DEA) [Organic intermediate products]** | **2.38E-06** | **kg** |
| Water (ground water) [Water] | 2.75E-03 | kg |
| **Outputs** | | |
| **Natural Gas, Sweetened** | **1.00** | **kg** |
| Carbon dioxide [Inorganic emissions to air] | 8.68E-02 | kg |
| Methane [Organic emissions to air (group VOC)] | 1.27E-06 | kg |
| **Vented gas [Intermediate product]** | **9.72E-04** | **kg** |
| Nitrous oxide (laughing gas) [Inorganic emissions to air] | 3.53E-07 | kg |
| Nitrogen oxides [Inorganic emissions to air] | 5.38E-08 | kg |
| Sulphur dioxide [Inorganic emissions to air] | 3.23E-10 | kg |
| Carbon monoxide [Inorganic emissions to air] | 4.52E-08 | kg |
| NMVOC (unspecified) [Group NMVOC to air] | 2.96E-09 | kg |
| Dust (PM10) [Particles to air] | 4.09E-09 | kg |
| Lead (+II) [Heavy metals to air] | 2.69E-13 | kg |
| Water (Evaporated) [Water] | 2.75E-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 1.

## Embedded Unit Processes

None.

## References

API 2009 — American Petroleum Institute. 2009. "Compendium of Greenhouse Gas Emissions for the Oil and Natural Gas Industry." 2009. Available at: http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf (Accessed May 18, 2010).

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## Section III: Document Control Information

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