

# Methane emissions from natural gas transport

March 2009

S. Murrath

Master of Science – Thesis

School of Science

Open University of the Netherlands

Master Programme  
Natural and Environmental Sciences  
at Open University of the Netherlands

2007-2008

SA FLUXYS NV, Brussels, Belgium

Project guidance/Examination committee:

Examinator (Open Univ.): prof. dr. L. Reijnders & dr. W. Ivens

Examinator (Fluxys): M. Vanden Brande

Coordinator (Open Univ.): drs. P. Geluk

*Keywords: Methane emissions, Greenhouse gas, Natural gas transport*

*Summary - During the 20th century the concentration of so called greenhouse gases in the troposphere has significantly increased. The Kyoto Protocol creates a framework for the reduction of greenhouse gas emissions. In this context reliable inventories of methane emissions are necessary. The regulation concerning methane emission monitoring and the application of the Kyoto protocol for methane emission reduction have been postponed, due to the lack of precise quantification methodologies.*

*This research aims to establish a survey of different quantification methodologies applied to a high pressure transportation grid. An evaluation of the qualitative aspects and a quantitative comparison of the methane emissions are given. The IPCC Guidelines define two main different approaches to make emission inventories: The Top-down method (Tier 1) use aggregated emission factors based on national production data. The Bottom-up method (Tier 3) is a rigorous source specific evaluation, requiring detailed inventories of infrastructure.*

*The Tier 1 method results in an emission rate of 0.05% (GWh CH<sub>4</sub>/GWh natural gas transported) or 4 ton CH<sub>4</sub>/km. Different publications were examined. Despite the fact that there is a lack of transparency, a high uncertainty and a variety of approaches, the five latest publications give similar results.*

*The Tier 3 method results in an emission rate of 0.01% (GWh CH<sub>4</sub>/GWh natural gas transported) or 1 ton CH<sub>4</sub>/km. This methodology is time consuming. A rigorous registration and investigation allows to set up a reduction plan.*

*cedr Based on these results, measures to reduce the methane emissions are analyzed. The most beneficial abatement options are those with the best efficiency index (implementation cost/emission reduction).*

*The best abatement option of each activity is:*

- *Maintenance emissions - Reducing the line pack pressure.*
- *Operational emissions - Replacing high bleed to low bleed devices.*
- *Compressor emissions - Avoid depressurizing after unit shut down.*
- *Incidental emissions - Using ultrasound to detect leaks.*

*It may be recommended to*

- *Implement an integrated program for lowering the emissions of methane as a main part of the policy of each facility.*
- *Set up a measurement program to gather field data to compare and approve the use of emissions factors and estimations.*
- *Where changes in activity and emission factors are substantial, the whole time series should be recalculated in a transparent manner.*

*Samenvatting*  
*Samenvatting - Tijdens de 20ste eeuw is de concentratie van zogenaamde broeikasgassen in de troposfeer beduidend gestegen. Het protocol van Kyoto schetst een kader voor de reductie van broeikasgasemissies. In deze context is het noodzakelijk om over betrouwbare meetgegevens te beschikken. De reglementering betreffende de opvolging van methaanemissies en de toepassing van het protocol van Kyoto zijn uitgesteld bij gebrek aan nauwkeurige kwantificeringsmethoden.*

*Sleutelwoorden: Methaanemissies, Broeikasgas, Aardgastransport*

*Dit onderzoek heeft als doelstelling om een overzicht van verschillende kwantificeringsmethoden toe te passen op een aardgastransportnet op hoge druk. De kwalitatieve en kwantitatieve aspecten worden vergeleken en geëvalueerd. Volgens de richtlijnen van het IPCC zijn er twee verschillende benaderingen om methaanemissies te berekenen: De Top-down methode (Tier 1) gebruikt emissiefactoren die op nationale gegevens zijn gebaseerd. De Bottom-up methode (Tier 3) is een gedetailleerde bron specifieke benadering, die een goede kennis van de infrastructuur vereist.*

*De Tier 1 methode resulteert in een hoeveelheid methaanemissie van 0.05% (CH<sub>4</sub> GWh/ getransporteerd aardgas GWh) of 4 ton CH<sub>4</sub>/km. Verschillende publicaties werden onderzocht. Ondanks een gebrek aan transparantie, een hoge onzekerheid en een verscheidenheid van benaderingen, geven de vijf recentste publicaties gelijkaardige resultaten.*

*De Tier 3 methode resulteert in een hoeveelheid methaanemissie van 0.01% (CH<sub>4</sub> GWh/ getransporteerd aardgas GWh) of 1 ton CH<sub>4</sub>/km.*

*Deze berekeningsmethode is tijdrovend. De volledigheid van de registratie en het gedetailleerde onderzoek staan toe om een reductieplan op te stellen.*

*Deze resultaten dienen als basis om reductiemaatregelen te analyseren. De voordeligste reductiemaatregelen zijn die met de beste efficiëncyindex (implementatie kost/de emissiereductie).*

*De beste reductiemaatregel van elke activiteit is:*

- *Onderhoud - de druk van de linepack verminderen.*
- *Operationele – high bleed apparaten vervangen door low bleed.*
- *Compressie – Geen afblaas na een shutdown.*
- *Incidenten – Ultrasound lekdetectie*

*Volgende punten worden geadviseerd:*

- *Het opzetten en implementeren van een geïntegreerd beleidsprogramma om de methaanemissies te reduceren.*
- *Een meetprogramma opzetten om gegevens te verzamelen van op het terrein met als doel deze te vergelijken met de gebruikte emissiefactoren en de schattingen te bevestigen.*
- *Waar de veranderingen in activiteit en emissiefactoren aanzienlijk zijn, zouden de gegevens op een transparante manier herberekend moeten worden.*

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## 1 Introduction

### 1.1 Problem description

#### 1.1.1 Greenhouse Effect <sup>(a)</sup>

The Earth is warmed by radiant energy from the sun. The amount of energy transmitted to the Earth's surface is approximately equal to the amount of energy re-radiated back into space in the form of infrared radiation, and the temperature of the Earth's surface stays roughly constant. However, the temperature of the Earth is strongly influenced by the existence and composition of its atmosphere.

Many gases in the Earth's atmosphere absorb infrared radiation that is "re-radiated" from the surface, trapping heat in the lower atmosphere. *Without this natural "greenhouse effect" it is likely that the average temperature of the Earth's surface would be in the order of -18° Celsius, rather than the +15° Celsius actually observed.* (IPCC, 1996)

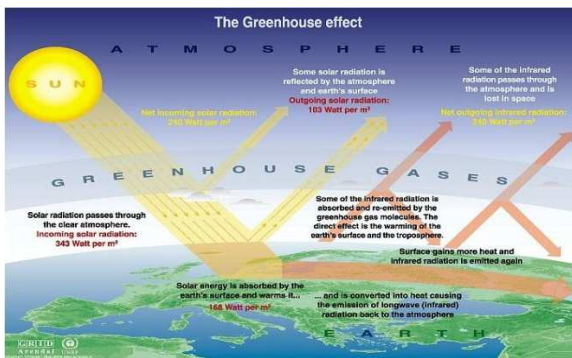


Figure 1: Greenhouse Effect (Energy Information Administration, 2000)

The gases that help trap the Sun's heat close to the Earth's surface are referred to as "greenhouse gases." All greenhouse gases (GHGs) absorb infrared radiation (heat) at particular wavelengths. It is the absorptive capacity of GHGs that determines their global warming potential (GWP). The most important greenhouse gases are water vapor (H<sub>2</sub>O), carbon dioxide (CO<sub>2</sub>), **methane (CH<sub>4</sub>)**, nitrous oxide (N<sub>2</sub>O), and several engineered gases, such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF<sub>6</sub>). Water vapor is by far the most common GHG, with an atmospheric concentration of nearly 1 percent, compared with less than 0.04 percent for carbon dioxide. Concentrations of other GHGs, such as CH<sub>4</sub> and N<sub>2</sub>O, are a fraction of that for CO<sub>2</sub>.

(a) Energy Information Administration, 2000, Emissions of Greenhouse Gases in the United States 1999, U.S. Department of Energy DOE/EIA-0573 (99).

#### 1.1.2 Methane Emissions

Methane emissions originate from three source categories each contributing approximately one-third of CH<sub>4</sub> emissions: energy consumption, waste management and agriculture. Methane emissions from gas systems account for 21 percent of the anthropogenic methane emissions (INGAA Foundation, 1999), and 8 percent from the total global emissions (USEPA, 2006). *While natural gas systems comprise the largest source of methane emission within the energy sector, it is the second largest source of total methane emissions.*

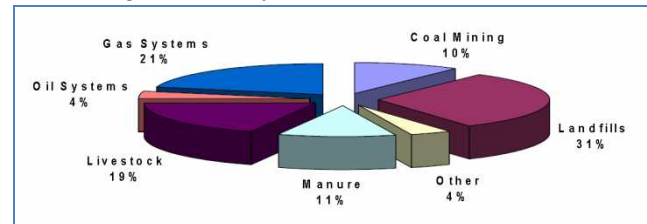


Figure 2: Percent of Methane Emissions from Anthropogenic Sources (INGAA Foundation, 1999)

#### 1.1.3 Regulation

The framework for activities regarding greenhouse gas emission reduction is created by the Kyoto Protocol, forcing signatories to achieve final emission quota and defining a time limit for emissions reduction. The international community, governments, NGO's and all branches of economy participating in emissions of greenhouse gases are interested in these activities. The flexible mechanisms such as emission trading, the clean development mechanism and joint implementation introduced by the Protocol make it easier reaching the assigned targets.

Nowadays there is not a lot of information available about the quantification of methane emissions from a natural gas transportation grid. The exact sources of methane emissions from a transportation grid are barely known. *A reliable and precise inventory of greenhouse gas emissions is the starting point of all activities aiming an emission reduction.* In the literature a wide array of guidance documents for emission inventories exist, but the most recent inventories are performed according to the methodologies described by the Intergovernmental Panel of Climate Change (IPCC) in "Good practice guidance and uncertainty management in national greenhouse gas inventories, 2001". Due to the high uncertainty level of these methodologies, the determination of regulation concerning methane emission monitoring and the application of the Kyoto protocol to reduce methane emission have been postponed.

## 1.2 Aim of this Study

The first challenge is to analyse different existing methodologies to quantify the methane emissions on a natural gas grid at high pressure. The next challenge is to list and to study different existing abatement options to reduce the emissions. The findings presented here, can be used as a basis for an emission reduction plan.

### 1.2.1 Research Questions

1. What are the different sources of methane emissions on a natural gas transportation grid? Which 'state of the art' quantifying methods exist to quantify the methane emissions at a high pressure transportation grid?
  - A. What are the (different) emission results from these methods? (expressed in ton CH<sub>4</sub> emission per kilometre and ton CH<sub>4</sub> emission per transported energy)
  - B. What are the quantitative and qualitative differences between the different methodologies?
  - C. What is the relevance of these methods?
  - D. Which is the most appropriate quantification method in this case?
2. Which alternatives exist to reduce methane emissions on high pressure natural gas transportation grids?
  - A. What are feasible abatement options for the different emissions sources?
  - B. What are the differences between those abatement options?
  - C. What is the economical, the ecological (emission reduction), and the technical and operational impact when implementing the "abatement methods"?
  - D. Are on the basis thereof suggestions to be made for an emission reduction plan?

### 1.2.2 Research methods

#### • Emission quantification

There are different approaches to make emission inventories by the natural gas industry described by the IPCC Guidelines:

- The *Tier 1* method uses aggregate production-based emission factors and national production data <sup>(b)</sup> (IPCC, 2001).
- The *Tier 3* method is a rigorous source specific evaluation, requiring a detailed inventory of infrastructure, and detailed bottom-up emission factors. These emissions are difficult to quantify

(b) There is no Tier 2 method for natural gas systems in the IPCC Guidelines.

accurately due to the large number and variety of potential emission sources and the limited availability of emission source data (IPCC, 2001). This thesis will describe, apply, compare and evaluate the different approaches:

#### • According to IPCC Guidelines Tier 1 (Top-down):

1. Based on emission factors (EF) by region,
2. Based on EF by gas industry segment (ISI data),
3. Based on EF by gas industry segment (GRI-EPA),
4. Based on EF by gas industry segment (IGU data),
5. Based on EF by gas industry segment (US and Canadian data),
6. Based on EF by gas industry segment (Russian data),
7. Based on EF by gas industry segment (North American data),
8. Based on the Net Balancing Method.

#### • According to IPCC Guidelines Tier 3 (Bottom-up):

1. Pressure Decay Method,
2. Process Induced Emissions, based on emission factors by gas emitting components of a model grid (documentation and manuals).

#### • Abatement options

Based on the results of the Tier 3 quantification analysis, different abatement options will be analyzed for the transmission segment of a natural gas system. The transmission segment of a natural gas system consists of transmission pipeline networks, compressor stations, metering and pressure-control stations. The abatement options will take into account the variety of emission sources (which are in the categories: maintenance, incidents and operational). The abatement technologies available to the transmission segment will be examined thoroughly as to their emission-reduction, economical, technical and operational aspects.

### 1.2.3 Scope: Model Gas System Characteristics

The calculations of methane emission from a natural gas grid have been performed for a virtual model gas system of following characteristic:

- The total length of gas transmission grid counts 3800 km.
- It contains 4 compressor stations and 1 storage station. The compressor stations have a capacity of 116 643 kW, 28 centrifugal and 3 piston compressors having approximately 35838 working hours per year. The underground gas storage facilities produced a throughput of 1130 million m<sup>3</sup>(n) in 2007.

- The throughput of natural gas transported in 2007 was about  $38,6 \cdot 10^9 \text{ m}^3(\text{n})(\text{c}) / 1\,546 \text{ PJ} / 429685 \text{ GWh}$ .
- The operating pressure is equal or greater than 14.7 bar, but usually **66 – 80** bar.
- On the grid there are 930 metering and pressure-control stations installed with the following gas emitting instruments: 93 I/P Transducers, 428 Boosters, 341 Positioners (Actuators), 730 Process controllers and 270 Analyzers.
- 450 end-users are connected to its grid, it consists of 48 % industries, 46 % public distribution and 6 % power plants.
- The weighted average of the gas density is  $0.81 \text{ kg/m}^3$ .

It may be assumed that the chosen model gas system is a typical high pressure transportation grid for a small country, with a very high population density, for which the natural gas system acts as a hub for neighbouring countries.

The following methane emissions will be kept outside the system boundaries for this study: The LNG plants, the public gas distribution systems and the methane emissions due to incomplete combustion of natural gas.

## 2 Methods for quantification of methane emissions

### 2.1 Emission Factors Tier 1

The *Tier 1* method uses aggregated emission factors per year based on national production data. The different emission factors are listed in chronological order of publication.

#### 2.1.1 Aggregated emission factors by world region

In Table 1 aggregated emission factors by region are listed. The emission factors are assigned to different world regions, which can be in many cases a subject of discussion. These emission factors consist of emissions due to gas transmission, processing and distribution.

	Aggregated emission factor
<b>World region</b>	Kg CH <sub>4</sub> /PJ of gas consumed
Western Europe	Min: 72 000 Avg: 84 500 Max: 133 000
USA & Canada	57 000 – 118 000
Other Oil exporting countries and rest of the world	118 000

**Table 1: Aggregated emission factors for gas industry (gas transmission, processing and distribution) (IPCC, 1996).**

#### 2.1.2 Emission factors by gas industry segment (ISI data, Previous West Germany)

The coefficients of methane emission from natural gas system used in German Inventory carried out by the ISI (Institut Systemtechnik und Innovationsforschung) are listed in Table 2. In this table the emissions on the distribution grid are completely ignored.

Gas industry segment and element		Methane Emission Factor
Transmission	Pipelines	223 m <sup>3</sup> /y.km
	Compressor stations	7.75 m <sup>3</sup> /y.kW
	Metering and regulation station	823 m <sup>3</sup> /y. station

**Table 2: Emission factors of methane emission by the ISI (Reichert, 2000).**

#### 2.1.3 Emission factors by gas industry segment (GRI-EPA study)

The study of GRI/EPA, Global Reporting Initiative - Environmental Protection Agency, divided the industry into segments to construct a detailed emission inventory for the year 1992. These segments include: field production, processing, transmission and distribution. This study produced emission factors and activity factors for over 100 different emission sources within the natural gas system. Since publication, the EPA has updated activity data in 2001. In Table 3 the methane emission factors from GRI-EPA are listed.

(c) A normalized cubic meter m<sup>3</sup>(n) is the quantity of dry gas at a temperature of 0°C and an absolute pressure of 1.01325 bar.

Gas industry segment and element		Methane Emission Factor
Transmission	Pneumatic Device Vents	3 564 m <sup>3</sup> /y. device
	Pipeline Blow down	5.4 m <sup>3</sup> /y.km
	Pressure Relief Valves	0.96 m <sup>3</sup> /y.PRV
	Mishaps	11.8 m <sup>3</sup> /y.km
Compressor Stations	Compressor Exhaust Vented Gas Engines	0.0068 m <sup>3</sup> /HPHr
	Compressor Blow down	107 m <sup>3</sup> /y.comp
	Compressor Starts	239 m <sup>3</sup> /y.comp

**Table 3: Emission factors from GRI-EPA (2001).**

#### 2.1.4 Emission factors by gas industry segment (International Gas Union (IGU) experts)

IPCC recommends the use of these data to assess completeness of inventory, but IGU experts considered them as default values because they are based on many literature sources and on experience of many gas companies. To use these emission factors only basic data on gas system activity are required and there is no danger of confusion caused by the different assignment of gas grid elements.

Doubt could arise when choosing among low, medium or high emission of gas grid element as there are no recommendations on that choice.

Gas industry segment and element	Emission Factor	
Transmission pipeline	200 m <sup>3</sup> / y.km	(low value)
	2 000 m <sup>3</sup> / y.km	(medium value)
	20 000 m <sup>3</sup> / y.km	(high value)
Compressor station	6 000 m <sup>3</sup> / y.MW	(low value)
	20 000 m <sup>3</sup> / y.MW	(medium value)
	100 000 m <sup>3</sup> / y.MW	(high value)
Underground gas storage	0.05 % of working capacity / y	(low value)
	0.10 % of working capacity / y	(medium value)
	0.70 % of working capacity / y	(high value)

Metering and Regulation Station	1 000 m <sup>3</sup> / y.station	(low value)
	5 000 m <sup>3</sup> / y.station	(medium value)
	50 000 m <sup>3</sup> / y.station	(high value)

**Table 4: Emission factors for Selected Types of Natural Gas Facilities. (IPCC, 2001)**

#### 2.1.5 Aggregated emission factors by gas industry segment (US and Canadian data)

In Table 5 aggregated emission coefficients determined lately for the transmission and storage segment of the US and Canadian gas grid are listed. They are useful in some national inventories despite that they are performed in countries of different world regions. At the same time it is strongly recommended to use them with care and only in case of similarity of gas system.

(Steczko et al.,2004)

Notice that in several countries different assignment of gas system elements to gas system segments is possible: city gate stations can be included into transmission or into distribution segment. It means that if inventory is intended to base on aggregated emission coefficients determined in foreign country it is better to use consequently the whole set of them than to choose from different sets.

The use of foreign emission coefficients expressed in methane mass or volume unit per activity unit is also unsafe, because the methane concentration in natural gas is not specified – even in natural gases of high methane content, this concentration can vary more than 15%.

Gas industry segment and element	Aggregated emission factor	Source of data
Transmission (including pipelines and surface facilities: compressor stations and gas stations)	3.4 Mg CH <sub>4</sub> /y.km transmission pipelines	Canada
	3.7 Mg CH <sub>4</sub> /y.km of transmission pipelines	USA
Storage (including all storage facilities)	0.84 Mg CH <sub>4</sub> /y. 10 <sup>6</sup> m <sup>3</sup> of gas stored	Canada
	5.8 Mg CH <sub>4</sub> /y. 10 <sup>6</sup> m <sup>3</sup> of gas stored	USA

**Table 5: Aggregated emission factors for different gas industry sectors based on US and Canadian data (IPCC, 2003).**

**2.1.6 Emission factors by gas industry segment (Russian natural gas pipeline system)**

The Wuppertal Institute for Climate, Environment & Energy and the Max Planck Institute for Chemistry in Germany developed a measurement program based on internationally accepted methods. The project received extensive technical and logistical support from Ruhrgas, Gazprom, the VNIIGaz Institute and the three subsidiaries of Gazprom in whose network the measurements were carried out.

In Table 6 the coefficients of methane emission for the natural gas system in Russia are listed.

Gas industry segment and element		Methane Emission Factor
Transmission	Maintenance & Repair	3 750 m <sup>3</sup> CH <sub>4</sub> /y.km
	Breakdowns	284 m <sup>3</sup> CH <sub>4</sub> /y. km
Compressor Stations	Startup / Shutdowns	15 400 m <sup>3</sup> CH <sub>4</sub> /y.compressor
	Shop Venting	105 000 m <sup>3</sup> CH <sub>4</sub> /y.station
	Filter Cleaning	44 359 m <sup>3</sup> CH <sub>4</sub> /y.station

**Table 6: Emission factors of methane emission by Gazprom** (Wuppertal Institute for Climate, Environment, Energy / Max-Planck-Institute for Chemistry, 2003).

**2.1.7 Emission factors by gas industry segment (North American data)**

In Table 7 aggregated emission coefficients for transmission, and storage segment of North American gas grid are listed. They are helpful in some national inventories despite that they are performed in countries of different world regions. At the same time it is strongly recommended to use them with care and only in case of similar gas system. Whenever actual vented volumes are known, they should be used to determine venting emissions rather than applying the represented emission factors.

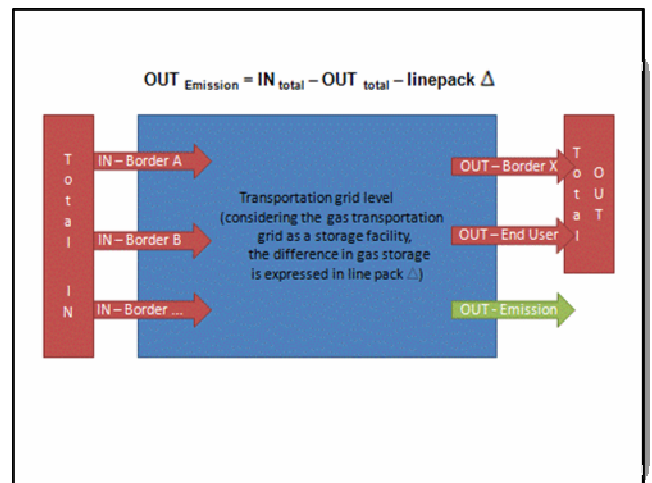
The emission factors for direct estimation of CH<sub>4</sub> emissions in Table 7 use 0.66 kg/m<sup>3</sup> of gas vented based on a typical North American gas analysis for gas transmission system (i.e 97.3% CH<sub>4</sub>, 0.26% CO<sub>2</sub>, 1.7 % N<sub>2</sub> and 0.74% non methane hydrocarbons by volume).

Gas industry segment	Aggregated emission factor	
Transmission fugitive	2.1 Mg CH <sub>4</sub> /y.km transmission pipelines	Centrifugal Compressors
	2.9 Mg CH <sub>4</sub> /y.km of transmission pipelines	Reciprocating Compressors
Transmission Venting <sup>d</sup>	0.8 Mg CH <sub>4</sub> /y.km transmission pipelines	(low value)
	1.2 Mg CH <sub>4</sub> /y.km transmission pipelines	(high value)
Storage	0.43 Mg CH <sub>4</sub> /y.10 <sup>6</sup> m <sup>3</sup> gas withdrawals	(low value)
	4.20 Mg CH <sub>4</sub> /y.10 <sup>6</sup> m <sup>3</sup> gas withdrawals	(high value)

**Table 7: Emission factors for fugitive emissions from gas operations based on North America Data (IPCC, 2007).**

**2.1.8 Net-Balancing Method**

The Net-Balancing method considers the unaccounted amount, as losses. This approach is susceptible to substantial uncertainties and may easily be in error by an order-of-magnitude or more. For this reason, it should be used as a last resort option (IPCC, 2001).



**Figure 3: Schematic presentations of the Technical Net Balance**

<sup>d</sup> 'Venting' is defined as waste gas volumes from blow down, purging and emergency relief events.

## 2.2 Emission Factors Tier 3

### 2.2.1 Introduction

IPCC Tier 3 (*IPCC 1996, IPCC 2003*) approach requires an extensive inventory of methane emission from the gas system (bottom up approach based on rigorous assessment of emission from individual sources). This needs a much more detailed knowledge on gas grid elements (including lifetime, working pressure, construction material, dimensions, technical design, maintenance and inspection program) and own emission measurement data.

### 2.2.2 Classification of methane emissions sources

The fugitive emissions from this grid model are divided in three major categories of emissions: maintenance (mostly “one shot” losses), incidents (accidents) and operational processes (mostly “permanent” vents).

#### 2.2.2.1 Maintenance (one shot)

The vented emissions from maintenance are resulting from intentional events that purge the gas into the atmosphere, such as emissions from planned operations, replacement activities, and emergency shutdowns (ESD). In particular, these emissions are due to the discharge of the natural gas contained in the piping involved.

#### 2.2.2.2 Incidents (accidental)

The vented emissions from incidents are mainly coming from leaks or accidental events. Accidental events can originate in uncontrolled external interference. They may also originate in mistakes regarding design, operation and maintenance. Accidental emissions are obviously involuntary. Leaks can occur at fittings (valves, flanges,...) which may leak because of their design. Any leak arising will be considered to be remedied immediately.

#### 2.2.2.3 Operational process (permanent or semi-permanent)

- *Fixed emission amounts*

The vented emissions from operational processes are resulting from several sources:

- compressor stations, such as compressor blow down, starter gas use due to the discharge of the power gas during operation of the starter turbine,

- starter purge, seal oil systems at the shaft seals of compressors,... ;
- filter cleaning operations;
- measurement instruments such as chromatographs, oxygen analyzer, sulfur analyzer, hydrocarbon dewpoint analyzer, water dewpoint analyzer,...

- *Variable emission regime*

The emissions from pneumatic devices originate in the gas which is actuating throttle- and pressure relieve valves at compressor, metering and pressure-control stations. Throttling valves are the pressure level controllers. Pressure relieve valves are the valves that can be opened or closed with gas. Although the pressure relieve valves have the highest gas discharge rate per actuation, they are infrequently moved. The throttling devices act repeatedly and thus manifest the highest annual emission rate per device of the two types (*Premoli & Riva, 2003*).

### 2.2.3 Classification of quantification methods

In practice, the ideal case of IPCC Tier 3 evaluation on the basis of measurements is very difficult as:

- even “small” gas grids develop quickly and are composed of numerous elements
- the measurements are time-consuming and expensive.

In an attempt to quantify the methane emissions following Tier 3, the following approach was taken.

- For incidents and interventions, the emissions are calculated following the Pressure Decay Method (See §2.2.3.1, by multiplying the affected volume of the grid with its respective pressure release.
- The process induced emissions are determined with the help of emission factors and activity factors (See §2.2.3.2, based on the data from the manuals of the instruments. (chromatographs, oxygen or hydrocarbon analyzers, regulators, actuators,...).

#### 2.2.3.1 Pressure Decay Method (PDM)

The Pressure Decay Method is based on the measurement of the fall in pressure on an isolated section. The gas emission is proportional to the change in pressure. To calculate the emission values using this method, the volume of the pipe section that is to be evaluated must be known.

$$Emissions \left[ m^3(n) \right] = Volume (m^3) \times \Delta pressure$$

The accuracy achieved through calculation by the PDM is almost the same as that which could be achieved by measurement or estimation and less complicated to carry out. (Casson et al., 1995a and 1995b and Rose, 1994).

### 2.2.3.2 Emission factors and Activity factors (EFAF)

It is in practice almost impossible to measure all the emissions and therefore the way to calculate methane emissions is based on the use of emission factors and activity factors with following equation:

$$Emissions [m^3(n)] = \sum (Activity\ Factor \times Emission\ Factor) \quad (e)$$

The activity factors are the population of emitting equipment (such as valves, pneumatic devices), and the frequency of emitting events (such as operating vents). Because of the large number and the wide variety of (potential) emission sources in the gas transportation system considered here, the activity factors must be often estimated with a statistical approach based on random sample of emission sources.

The emission factors are defined as the quantity of methane emitted from each emitting source and for each emitting event. Some emissions factors can be calculated or measured, such as the gas vented for operating reasons, some others can be evaluated on the basis of the characteristic of components, such as the emissions from analyzers, others are very difficult to be evaluated or measured, such as those deriving from pneumatic devices. The emission factors are strongly dependent on pipeline material, pressure level, maintenance, location and, in some cases, of pipeline ageing.

The analysis of the different emitting components, the determination of the emission factor and the evaluation of the activity factors, based on the user manuals, are described in the appendix.

### 2.2.4 Relation between natural gas emissions and methane emissions

To convert natural gas emissions to methane emissions, the factor of 0.9 is applied (Fluxys, 2007). Knowing the volume,  $V_i$ , of natural gas, the values of the volume of methane emitted,  $V_{mi}$ , can be calculated from the

(e) A normalized cubic meter  $m^3(n)$  is the quantity of dry gas at a temperature of 0°C and an absolute pressure of 1.01325 bar.

expression:  $V_{mi} = 0.9 V_i$ . When it is needed to express methane emissions in units of mass, the weighted average 0.81 (kg/m<sup>3</sup>(n)) is used (Fluxys, 2007). To convert tons of methane to equivalent tons of CO<sub>2</sub>, the factor of 21 is applied. The Fourth Assessment Report by the IPCC puts the greenhouse gas effect for methane at 25 times that compared with CO<sub>2</sub> and over a period of 100 years<sup>(f)</sup>. However it is the Second Assessment Report - SAR (IPCC, 1995) which is legally binding for the issues associated with the Kyoto Protocol, and that puts the greenhouse gas potential at 21.

The total estimated emissions will be related:

- ⇒ with the total network length at year end in kilometers:

$$V = \frac{\sum_i V_{mi}}{km\ of\ network} \quad [m^3(n) / km]$$

- ⇒ with the amount of gas fed through the network in GWh:

$$E = \frac{\sum_i V_{mi}}{quantity\ of\ gas\ fed} \quad [m^3(n) / GWh]$$

(f) To compare the relative climate effects of greenhouse gases the relative combustion of a gas is compared with the effect of a unit emission of carbon dioxide integrated over a fixed period of time (100 years). This factor is known as the global warming Potential (GWP). This method has been derived by the United Nations Framework Convention on Climate Change (UNFCCC).

### 3 Results: Quantification

#### 3.1 Overview Results following Tier 1

The different calculation methodologies and their respective emission factor values have been applied on the grid model. They are presented in chronological order. The detailed calculations are explained in the Appendix: Application of the different quantification methods.

The average emission rate is 0.05%, which means that for every 100GWh transported, 0.05GWh methane is emitted. This result (0.05%) doesn't take emission factors by region and by segment (ISI & GRI-EPA) into account. Emission factors by region lead to relatively high emission assessment (0.42%), which is due to the fact that the emissions of the distribution grid are included. On the other hand, the methodology by segment (ISI & GRI-EPA) results in relatively low emission values (0.005% & 0.01%). This is explained by the fact that the emissions on the distribution grid are entirely excluded.

Gas emissions based on Aggregated Emission Factors	Ton methane / Year	Ton methane / km	Ton methane / GWh	GWh methane/ GWh transp. nat. gas (%)
By Region - 1996	130 710	34	0.304	0.42
By gas industry segment (ISI) - 2000	1 835	0.483	0.004	0.005
By gas industry segment (GRI-EPA) - 2001	2 987	0.786	0.007	0.01
By gas industry segment (IGU) - 2001	11 455	3.014	0.027	0.04
By gas industry segment (US/Canada) - 2003	21 160	5.568	0.049	0.07
By gas industry segment (Russia) - 2003	13 287	3.497	0.031	0.04
By gas industry segment (N. America) - 2007	19 533	5.140	0.045	0.06
Net Balancing Method - 2007	17 742	4.669	0.041	0.06
<b>Mean</b>	<b>16 635</b>	<b>4.378</b>	<b>0.039</b>	<b>0.05</b>

Table 8: Overview Results following Tier 1. (Base year: 2007)

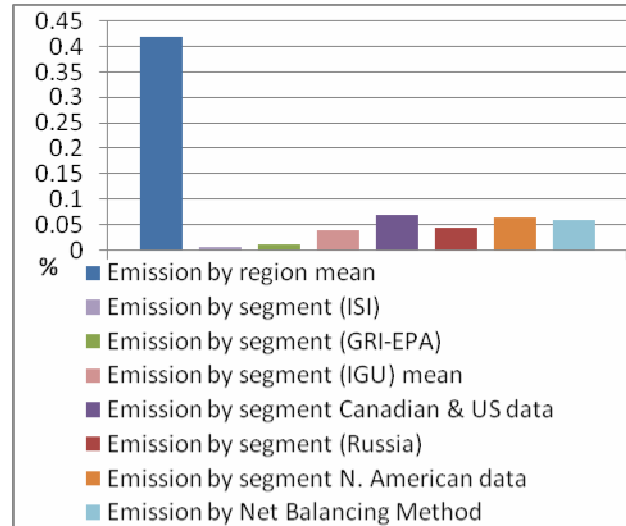


Figure 4: Overview results Tier 1 (GWh CH<sub>4</sub> / GWh transported - %)

#### 3.2 Overview Results following Tier 3

Table 9 gives a summary of the results, presented by emission type (maintenance, incident and operational) and by gas industry segment (grid losses - transmission, compression, storage, metering & pressure-control stations).

The emissions due to *maintenance* activities are calculated with the pressure decay method (PDM). This method is applied for interventions on the grid, and in storage, metering and pressure-control stations.

The emissions from *operational* processes are based on the emission and activity factors - EFAF.

The vented emissions from *incidents* are estimated by the best available ability, which can be PDM or EFAF.

Gas emissions (2007)	Emission quantity (m <sup>3</sup> / year)	Ton methane / Year	%	Methodology
<b>Maintenance</b>				
Grid losses	1 262 807	921	21.2	PDM
Compression (interventions)	43 154	31	0.7	PDM
Metering Stations	208 839	152	3.5	PDM
Pressure-control stations	744 000	603	13.9	PDM
Storage	294 575	215	4.9	PDM
<b>Incidents</b>	20 014	15	0.3	PDM/ EFAF
<b>Operational</b>				
Compression (start/stop)	483 329	352	8.1	EFAF
Compression (regulation)	336 604	245	5.6	EFAF

# Methane emissions from natural gas transport

valves)				
Metering Stations (Analyzers)	69 428	51	1.2	EFAF
ressure-control stations <sup>(g)</sup>	10 500 153	1 764	40.6	EFAF
<b>Total</b>	<b>5 882 698</b>	<b>4 349</b>	<b>100</b>	

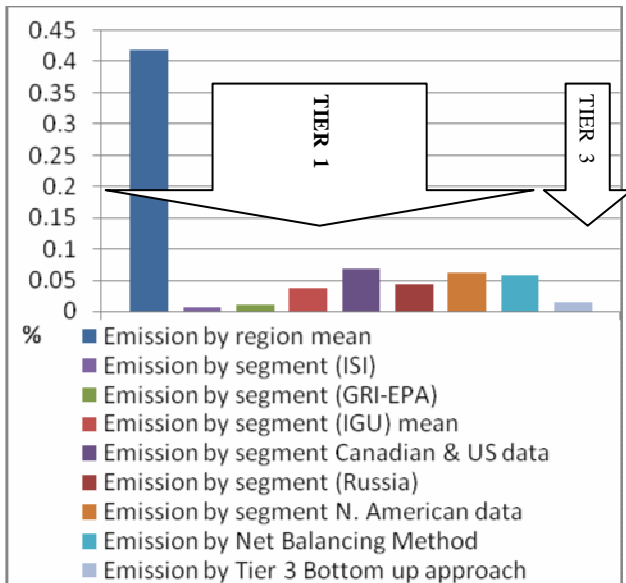
**Table 9: Quantification of emissions due to maintenance, incidents and operations.**

The different types of gas emitting instruments from operational processes are listed in Table 10 with their corresponding emission quantities. The detailed calculations of these methane emissions (based on the emission and activity factors - EFAF) are explained in Appendix: Application of the different quantification methods.

Gas emitting instruments (2007)	Ton methane / Year
I/P Transducer	8
Booster	1 375
Positioner (Actuator)	363
Process controller	18
Analyzers	51

**Table 10: Gas Emitting Instruments from operational process induced sources (2007).**

The next Figure and Table gives the average emission rates based on the Tier 3 approach in comparison with the Tier 1. The emission rate from the Tier 3 approach is 0.01% and is lower than the average emission rate following Tier 1.

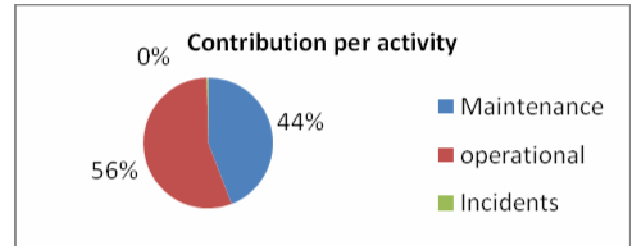


**Figure 5: Overview results of the different determination Methods (GWh CH<sub>4</sub> / GWh transported - %)**

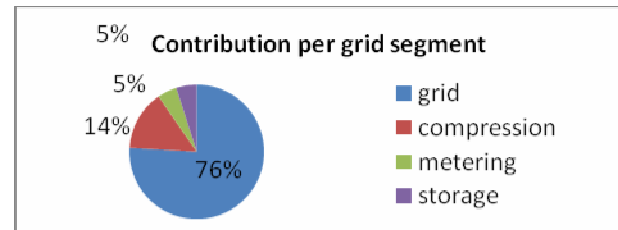
<sup>(g)</sup> In reference to Table 10

Gas emissions (2007)	Ton methane / Year	Ton methane / km	Ton methane / GWh	GWh methane/ GWh nat. gas (%)
By Tier 3 (bottom-up)	4 349	1.145	0.010	0.01

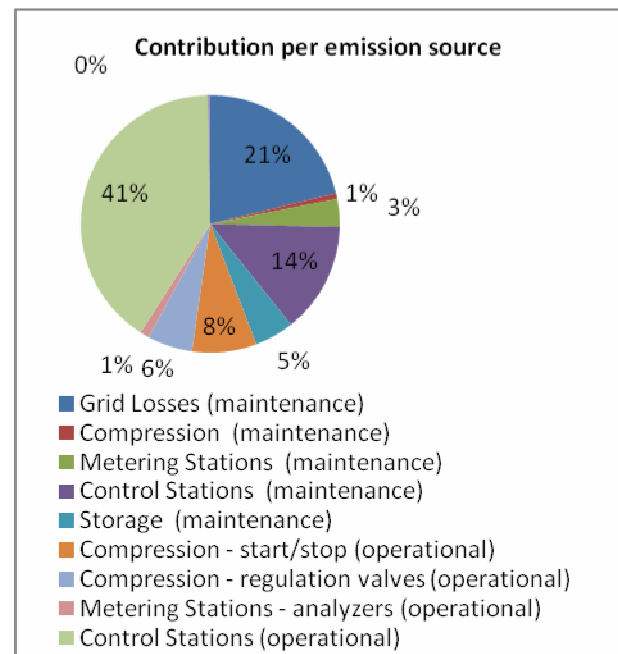
**Table 11: Overview Results following Tier 3. (Base year: 2007)**



**Figure 6: Overview contribution per activity following the Tier 3 determination Method**



**Figure 7: Overview contribution per grid segment following the Tier 3 determination Method**



**Figure 8: Overview contribution per emission source following the Tier 3 determination Method**

## 4 Abatement options

This chapter will highlight abatement options, based on the model gas grid and the results of the bottom up analysis (Tier 3). It will take into account the different categories of emission sources (maintenance, operational and incidental emissions as described in §2.2.2.

Only broad cost comparisons are possible due to the wide variations in specific site costs, labor charges, currency exchange rates, discount rates used.

For every abatement option, a detailed decision process chart exists (cfr. references). All facets of the processes are considered: implementing costs, maintenance costs, methane emission savings, natural gas savings, and payback time. This information is compared with the costs of alternative solutions.

It should be noted that a large number of abatement options for the natural gas sector are substitutes for each other. Thus, there may be several options for reducing emissions for a particular piece of equipment.

Following chapters give a short description of the different abatement options. A more thoroughly developed description of all abatement options is enclosed in the Appendix: Abatement Options. Every option has been analyzed on technical / operational, ecological and economical level.

### 4.1 Reduction of maintenance emissions

When pipeline segments are taken out of service for operational or maintenance purposes, it is common practice to depressurize the pipeline and vent the natural gas to the atmosphere.

The impacts associated with venting are both economic and environmental. Gas vented from the pipeline segment represents a loss of product and an increase in methane emissions. In addition, removing a pipeline segment from service can occasionally cause gas service interruptions to customers.

#### 4.1.1.1 Reducing the line pack pressure

Reducing the line pack pressure with specific procedures can be adopted to minimize the amount of natural gas that is vented into the atmosphere during extension works of the network and maintenance activities on pipelines. An integrated management of the grid, evaluating the pressure need at all supply points will save working hours of the compressor units, the regulation at control stations and leads to methane emission savings.

#### 4.1.1.2 Using Inert Gases to Perform Pipeline Purges

The inert gas is vented to the atmosphere until the pipeline contains the right “natural gas-inert gas mixture”. Another application where this can be used is when a pig is inserted into an isolated section of pipeline. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°405*)

#### 4.1.1.3 Using Hot Taps for in Service Pipeline Connections

Hot tapping is an alternative technique that allows the connection to be made without shutting down the system and venting gas to the atmosphere. The process involves attaching branch connections and cutting holes into the operating pipeline without interruption of gas flow, and with no release or loss of product. (*Natural Gas EPA Pollution Preventer, Lessons Learned, EPA-430-B-03-010, 2003*)

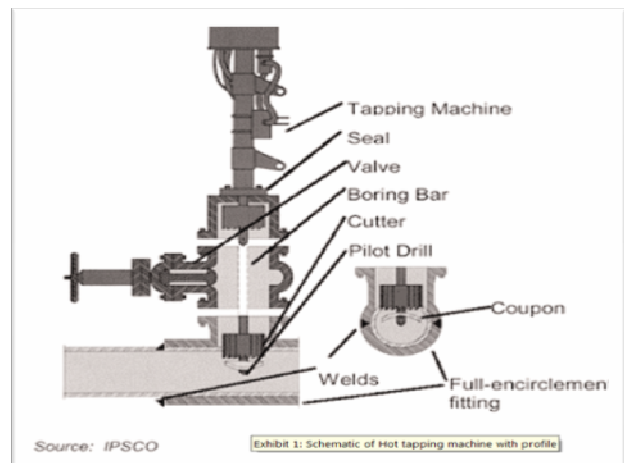


Figure 9: Schematic view of Hot Taps (*EPA 430-B-03-010, 2003*)

#### 4.1.1.4 Using Pipeline Pump-down Techniques

In implementing pipeline pump-down techniques, operators can use two types of compressors to reduce pipeline pressure: in-line compressors and mobile compressors. Typically, in-line pipeline compressors have compression ratios of up to 2 to 1. This type of line pump-down process should be done only in a manner consistent with safety management policies.

Operators can also consider using mobile compressors to achieve additional reduction beyond what in-line compressors can provide. Mobile compressors can have up to a 5 to 1 compression ratio. Again, safety policies should be strictly followed when using mobile compressor. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-04-002, 2004*)

#### 4.1.1.5 Inject Blowdown Gas into Low Pressure Mains

Emissions can be reduced through depressurizing to a connected or nearby low-pressure fuel or product system. Several options, driven by operational considerations, exist for performing this practice. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°401*)

#### 4.1.1.6 Flaring

##### - *Replacing Methane Emission by Combustion*

Flaring with a flare unit can be used to transpose methane emissions to carbon dioxide which is a less harmful greenhouse gas. There are significant safety and public perception issues to be considered. The main disadvantage is that the combustion takes several times longer which leads to an increase in hours spent on intervention. For this reason this is not applicable for Emergency Shut Downs (ESD). (*Natural Gas EPA Pollution Preventer, Fact Sheet n°905*)

##### - *Installing Flare Ignition Devices*

Some flares have one or more continuously burning pilot flames, while others save gas by only igniting pilot flames in preparation for use. Pilots can be blown out by wind and gas leakage and/or waste gas is occasionally released to an unlit flare. Both of these situations result in methane emissions to the atmosphere. This technology replaces the intermittently or continuously burning flare pilots with electrical pilots similar to a modern gas stove. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°303*)

## 4.2 Reduction of operational process emissions

### 4.2.1 Reduction at Metering & Pressure-Control Stations

The natural gas industry uses a variety of process control devices to automatically operate control valves that regulate pressure, flow, ... Most instrumentation and control equipment can be subdivided into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

### 4.2.1.1 Replacing High Bleed to Low Bleed Devices<sup>(h)</sup>

Pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device. Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-03-004, 2003*)

### 4.2.1.2 Retrofitting

The retrofit or complete replacement of worn units can provide better system performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level. Equipment retrofits or replacements can be combined with improved maintenance activities. Simple solutions should not be overlooked such as replacing tubes and fittings or rearranging controllers. Retrofitting is applicable to most of high bleed controllers. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-03-004, 2003*)

### 4.2.1.3 Directed Inspection and Maintenance

In general, the bleed ratio will vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years. Field survey of controllers and if possible tune controllers to minimize bleed should be added to the routine maintenance procedures. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-03-004, 2003*)

### 4.2.1.4 Closing Main and Unit Valves Prior to Blowdown

When equipment or facilities are taken out of service for operational and/or maintenance purposes, it is a common practice to close the main valves and vent the natural gas which is trapped between them, to the atmosphere. Methane emissions can be reduced by

(h) Definition of High Bleed Pneumatic Device: Any Pneumatic Device that bleeds in excess of 1415 m<sup>3</sup>(n)/year or 0.169 m<sup>3</sup>(n)/h is considered a high-bleed device by the Natural Gas STAR Program.

improving the operating practice. This involves closing the main and unit valves prior to blow down sections of isolated equipment. This option can be improved by using a double block and bleed. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°603*)

#### **4.2.1.5 Converting Natural Gas Supply of Pneumatic Devices**

##### **4.2.1.5.1 Converting to Instrument Air**

It is economical to substitute compressed air for natural gas in pneumatic systems. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system. Compressors used for instrument air delivery are available in various types and sizes. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA-430-B-04-003, 2004*)

##### **4.2.1.5.2 Converting to Electric and Electro-Pneumatic Devices**

As a result of advanced technology and increasing sophistication, the use of electronic instrument and control devices is increasing. The advantage of these devices is that they require no compression devices and that the use of electronic control devices is less dangerous than using combustible natural gas or cryogenic liquid nitrogen cylinders. The disadvantage of these devices is their reliance on an uninterrupted source of electric supply, and significantly higher costs because of Atex requirements.

##### **4.2.1.5.3 Converting to Liquid Nitrogen**

In a system using liquid nitrogen, the volume tank, air compressor, and dryer are replaced with a cylinder containing cryogenic liquid nitrogen. A pressure regulator allows expansion of the nitrogen gas into the instrument and control-piping network at the desired pressure. Liquid nitrogen bottles are replaced periodically. Liquid nitrogen-operated devices require handling of cryogenic liquids, which can be expensive as well as a potential safety hazard.

#### **4.2.1.6 Reducing purge gas flow**

Purge gas is normally applied in vent and flare systems of analyzing instruments to prevent air from entering the system. As the amount used is often unnecessarily high, reductions in methane emissions from this process can be achieved by reducing the amount of purge gas used. Reduced flows can be obtained by installing restriction

orifices or flow meters, however there is a safety issue in reducing gas purges.

#### **4.2.1.7 Testing Pressure and Temperature Relief Valves with Nitrogen**

Pressure relief valves (PRV's) or Temperature relief valves (TRV's) play a vital safety role by protecting gas pipelines. They are routinely tested (offsite) for the proper pressure setting by isolating them from the pipeline and activating them with natural gas pressure. Testing and adjusting the set-point pressure requires multiple tests or a continuing release of high-pressure gas. Testing relief valves with pressurized nitrogen gas supplied from cylinders requires a cylinder of gas at a pressure exceeding the PRV/TRV set point. The implementation can be facilitated by replacing the PRV's/TRV's on site during the maintenance programs, and to organize the testing in a centralized laboratory. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°609*)

#### **4.2.2 Reduction at Compressor Stations**

Options related to the use of compressors relate to both the compression equipment and also the engines or gas turbines used to power these machines. There is therefore some overlap between the options considered here for compressors and those which apply more generally to energy requirement. Measures to reduce emissions from compressors become more important since the liberalization leads to more frequent start-up and shut-downs in compressor systems. (*Eurogaz-Marcogaz, 2007*)

A first option, which is already implemented, is the adaptation of the frequency of maintenance work at compressor stations according to the number of hours which the machines run.

##### **4.2.2.1 No depressurizing after unit shut down**

Keeping compressors pressurized when they are off-line for operational reasons achieves immediate payback—there are no capital costs and emissions are reduced by avoiding "blow down." Two additional options further reduce methane emissions.

1. Connecting the blowdown vent lines to the fuel gas system.
2. A static seal can be installed on a pressurized compressor's rods to eliminate rod packing leaks during shutdown.

#### **4.2.2.2 Installation of Electric Compressors**

Electric motors reduce the chance of methane leakage by eliminating the need for fuel gas, require less maintenance, and improve operational efficiency. An electrical power supply is needed to implement this technology. Remote facilities with an available electrical power source and high compressor maintenance cost may be good options for this technology. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°105*)

#### **4.2.2.3 Lowering Purge Pressure for Shutdown**

Lowering the purge gas pressure by venting some of the high-pressure blow down gas to the fuel gas system results in lower methane emissions and generates savings by using the blow down gas for fuel to run other compressors at the station. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°105*)

#### **4.2.2.4 Replacing Compressor Cylinder Unloaders**

Unloaders have been identified as one of the top causes of unscheduled reciprocating compressor shutdowns. Multiple sealing elements can be used to reduce emissions while its plug-type design avoids the inherent operational problems and breakage associated with finger-type unloaders. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°110*)

#### **4.2.2.5 Reciprocating Compressor Rod Packing**

Reciprocating compressor rod packing leaks some gas by design. Leakage occurs through nose gasket, between packing cups, around the rings and between rings and shaft. A series of flexible rings fit around the shaft to prevent leakage. Leakage may still occur, but the gas emissions are reduced significantly.

#### **4.2.2.6 Reducing the Frequency of Engine Starts with Gas**

The unignited gas, or startup natural gas, is vented to the atmosphere. Operating and maintenance schedules prescribe how often such turbine engines can be restarted. This practice may be applied in operations which have multiple compressors in a parallel configuration. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°102*)

#### **4.2.2.7 Installing Electric Starters**

Internal combustion engines for compressors, generators, and pumps are often started using small gas expansion turbine starter motors. Replacing the starter expansion turbine with an electric motor starter, similar to an automobile engine starter, can avoid methane emissions. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°108*).

#### **4.2.2.8 Designing Isolation Valves to Minimize Gas Blow down Volumes**

The compressor station is designed with isolation valves positioned in closer proximity to compressors. Due to this design alteration, when the valves are closed, significant lengths of gas-filled piping will not be vented to the atmosphere. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°606*)

#### **4.2.2.9 Replacing Ignition – Reducing False Starts**

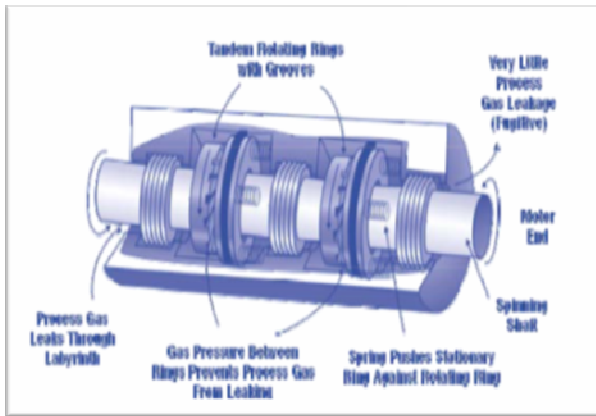
When the ignition system is in poor condition, the engine will not start promptly, or stall when the compressor is loaded. Each false engine start will result in excessive methane emissions. False starts can be reduced by directed maintenance and replacing old ignition systems with a newer system design. In addition to eliminating methane emissions from repeated false starts, new ignition systems can significantly reduce operating costs. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°104*)

#### **4.2.2.10 Automating Systems Operation to Reduce Venting**

Automatic control systems, such as programmable compressor ignition systems, reduce the number of start-ups and shutdowns. Programmable Logic Controllers (PLCs), incorporate features such as unit performance, process calculations, unit load management, independent safety shutdown, and automated backup control. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°106*)

#### **4.2.2.11 Dry gas seals**

Dry seal springs press the stationary ring in the seal housing against the rotating ring when the compressor is not rotating. At high rotation speed, gas is pumped between the seal rings creating a high pressure barrier to leakage. Only a very small amount of gas escapes through the gap. Two seals are often used in tandem.



**Figure 10: Schematic view of a Centrifugal Compressor Dry Seal**  
(Targa Resources and the Gas Processors Association – [epa.gov/gasstar](http://epa.gov/gasstar), 2006)

#### 4.2.2.12 Replacing reciprocating engines by gas turbines

The use of gas turbines instead of reciprocating engines will reduce methane emissions. Better design, monitoring and maintenance of engines and turbines will lead to emission savings of several percent.

### 4.3 Reduction of incidental emissions

#### 4.3.1 Prevention of damage to pipeline networks

The security policy in the natural gas sector takes the “precaution principle” as their highest priority. In this context it is worth mentioning that the pipelines are already routinely checked and maintained with a view to the early detection and remediation of any disruption and leak that could affect the transmission of gas. Regarding pipelines under high pressure, leaks that are significant for emissions attract attention through loud whistling or freezing or because the soil cover is blown away, so the likelihood of leaks going undetected is minimal or nil. Each pipeline section is checked yearly by foot patrols, biweekly/monthly by jeep patrols and in addition, the pipelines are regularly (crosscountry grids – daily) overflowed by helicopter. Intelligent “pigs” are used to assess the condition of the pipelines and assist in identifying potential problems before a leak can occur (WIC, 2003).

##### 4.3.1.1 Directed Inspection and Maintenance

Directed Inspection & Maintenance (DI&M) is a cost-effective way to reduce natural gas losses from equipment. A survey to identify leaking components need to be conducted in the first year of a DI&M program. In subsequent years, focus inspection and repair on the components that are the most likely to leak and that represent cost-effective emissions reduction opportunities.

Several leak screening techniques can be used: Soap Bubble Screening, Electronic Screening using small hand-held gas detectors or “sniffing” technique, Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) are portable hydrocarbon detectors, Ultrasound, Infrared or Acoustic Leak Detection (To quantify the methane emissions a high volume sampler, a toxic vapor analyzer, a rotameter or calibrated bagging can be used). (Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-03-007, 2003; Fact Sheet n°902)

##### 4.3.1.2 Composite Wrap Repair

Composite wrap is a permanent, cost-effective pipeline repair technology. Composite wrap can be performed on an operating pipeline without taking it out of service. This repair technique is quick and generally less costly than other repair options, and it permanently restores the pressure-containing capability of the pipe when properly installed. Composite wrap systems use different

materials for wraps and adhesives, and some systems use epoxy polymers and curing agents. (*Natural Gas EPA Pollution Preventer, Lessons Learned EPA430-B-03-017, 2003*)

#### 4.3.1.3 Pressure Safety Relief Valves

- **Placing Burst Plates with Secondary Relief valves**

Burst Plates are a low capital cost alternative to pressure relief valves, for the protection of process equipment when gas pressures rise to levels exceeding the maximum allowable operating pressure. These burst plates are for one-time use only. If the calibrated metal membrane (burst plate) is broken by excessive gas pressure, significant amounts of methane vent to the atmosphere. Installing PRVs on top of burst plates has the dual benefits of reducing fugitive leaks while the burst plate is intact, and minimizing gas release during pressure surges. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°612*)

- **Testing and Repairing Pressure Relief Valves**

A proactive testing and repair program can yield significant methane emissions reductions. Testing may be done with an organic vapor analyzer (OVA), acoustical leak detector, or high-volume sampler while PSVs are in service. Safety precautions must be taken while testing operating equipment.

#### 4.3.1.4 Implementing centralized information system

Prevention of accidental breakage during excavation or construction work can be done by implementing an information system of the pipeline locations.

1. Information to be gathered at the municipality;
2. Information in a meta-database which can be consulted through the internet.

#### 4.3.2 Detection of system upsets

System upsets may be caused by pipe breakage or pressure surges. This is a rare occurrence, with a frequency much lower than the frequency of maintenance depressurizations.

Gas stations are metering and pressure control facilities located at transfer points of the transmission pipelines. Gas stations contain equipment to monitor and control gas flow. Over time, these components can develop

leaks in response to temperature fluctuations, pressure, corrosion and wear.

#### 4.3.2.1 Using Ultrasound to Identify Leaks

Ultrasound leak detectors, like a stethoscope, listen to the unique noise of gas leakage through a valve. Electronics are used to filter out the low frequency noise of compressors and reveal high frequency sounds associated with gas leakage. When placed on pressure relief, blow down, starter motor, and unit isolation valves, the ultrasound detector indicates whether the valve is tightly shut and the magnitude of leakage. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°602*)

#### 4.3.2.2 Installing (semi-) Automatic Excess Flow Valves

The excess flow valve responds to the high-pressure differential, created when a line is severed, by snapping shut to stop the flow of gas. Therefore, the amount of gas that would otherwise have escaped into the atmosphere in the event of a rupture is retained within the closed system. The valves do not protect against slow leaks such as those caused by corrosion or loose fittings. (*Natural Gas EPA Pollution Preventer, Fact Sheet n°610*)

#### 4.3.2.3 Implementing alarm system

Detection of accidental breakage during excavation or construction work can be done by implementing an adequate alarm system to assess third party interference activities. Fiber optics are laid in close proximity or strapped on the pipelines. An alarm signal is generated when the fiber optic cable is touched or damaged. Some systems are even able to detect disturbances due to ground movements.

#### 4.3.2.4 Airborne Leak Detection

Airborne Natural Gas Emission Lidar (ANGEL) Service uses Differential Absorption Lidar (DIAL). This active remote-sensing technology detects, quantifies, images, and maps natural gas emissions while flying in an airplane about a quarter of a mile above a pipeline. The ANGEL Service captures high-resolution, geo-referenced digital images and video. The ANGEL Service collects nearly 180 000 laser measurements per minute, can survey the entire width of 38 meter (checking for migrating gas beneath the surface), and

can cover more than 1 500 km in one day. (EPA, *Natural Gas Pollution Preventor*, “Partner update“, Spring 2006.)

## 5 Results: Abatement Options

In previous chapter a (non) exhaustive list of abatement options is presented with an ecological, economic, operational and technical evaluation. When it comes to implementation of abatement options, all options should consider the lifecycle of the natural gas grid.

The tables below resumes the abatement options with their respective implementation costs, annual methane reduction, and an estimation of the payback time. The solutions are listed in order of the Efficiency Index. This is an index that compares the implementation cost and the emission reduction, expressed in \$/ton. This represents the return on investment.

EMISSION REDUCTION: MAINTENANCE				
Abatement Options	Implementation Cost	Methane Reduction (annual)	Payback (Years)	Efficiency Index (\$/ton meth.red.)
Reducing the linepack pressure	< \$ 1 000	300 ton	0-1	<3.33
Using Inert Gases to Perform Pipeline Purges	< \$ 1 000	100 ton	>10	<10
Using Hot Taps for in Service Pipeline Connections	> \$ 10 000	500 ton	0-1	>20
Using Pipeline Pump-down Techniques	\$ 75 000	475 - 800 ton	0-1	93-158
Inject Blowdown Gas into Low Pressure Mains	< \$ 1 000	3.5 ton	0-1	<286
Replace Methane emission by Flaring	> \$ 10 000	45 ton	n.a.	>222
Install Electronic Flare Ignition Device	\$ 1 000 - \$ 10 000	0.03 ton	1-3	33 333-333 333

Table 12: Overview Abatement Options for emissions due to maintenance activities.

## EMISSION REDUCTION: METERING & CONTROL STATIONS (OPERATIONS)

Abatement Options	Implementation Cost	Methane Reduction (annual)	Payback (Years)	Efficiency Index (\$/ton meth.red.)
Replacing High Bleed to Low Bleed Devices	\$ 1 350	700 ton	< 2	1.9
Retrofitting	\$ 5 000	500 ton	0-1	10
Directed Inspection & Maintenance	< \$ 2 500	176 ton	0-1	<14
Closing Main and Unit Valves Prior to Blowdown	< \$ 1 000	35 ton	0-1	<28
Converting Pneumatic Controls to Instrument Air	\$ 50 000	500 ton	0-1	100
Converting Pneumatic Controls to Electric and Electro-Pneumatic Devices	n.a.	500 ton	n.a.	n.a.
Converting Pneumatic Controls to Liquid Nitrogen	n.a.	500 ton	n.a.	n.a.
Reducing purge gas flow	< \$ 1000	5 ton	0-1	<200
Testing Pressure and Temperature Relief Valves with Nitrogen	< \$ 1 000	0.1 ton	> 10	<10 000

Table 13: Overview Abatement Options for emissions due to operational activities at metering and pressure-control stations.

## EMISSION REDUCTION: COMPRESSOR STATIONS (OPERATIONAL)

Abatement Options	Implementation Cost	Methane Reduction (annual)	Payback (Years)	Efficiency Index (\$/ton meth.red.)
No depressurizing after unit shut down	\$0 - \$3 000	0 – 87 ton	>0-4	0-34
Installation of Electric Compressors	> \$ 10 000	150 ton	>10	>67

# Methane emissions from natural gas transport

<b>Lowering Purge Pressure for Shutdown</b>	\$ 1 000 - \$ 10 000	11 ton	3-10	90-909
<b>Replacing Compressor Cylinder Unloaders</b>	\$40 000 - \$50 000	321 ton	0-1	125-155
<b>Reciprocating Compressor Rod Packing</b>	\$ 3 000	21 ton	0-1	143
<b>Reducing the Frequency of Engine Starts with Gas</b>	< \$ 1 000	3 ton	0-1	<333
<b>Installing Electric Starters</b>	> \$ 10 000	31 ton	1-3	>323
<b>Designing Isolation Valves to Minimize Gas Blowdown Volumes</b>	\$ 1 000 - \$ 10 000	3 ton	3-10	333-3333
<b>Replacing Ignition – Reducing False Starts</b>	\$ 1 000 - \$ 10 000	0.5 ton	0-1	2000-20000
<b>Automating Systems Operation to Reduce Venting</b>	> \$ 10 000	0.5 ton	0-1	>20000
<b>Dry gas seals</b>	\$240 000	5 ton	0-1	48000
<b>Replacing reciprocating engines by gas turbines</b>	\$ 1 000 - \$ 10 000	n.a.	3-10	n.a.

**Table 14: Overview Abatement Options for emissions due to operational activities at compressor stations.**

## EMISSION REDUCTION: PREVENTION (INCIDENTS)

Abatement Options	Implementation Cost	Methane Reduction (annual)	Payback (Years)	Efficiency Index (\$/ton meth.red.)
<b>Directed Inspection &amp; Maintenance</b>	< \$ 1 000	250 ton	1-3	4
<b>Composite Wrap Repair</b>	\$ 4 000	10 – 700 ton	0-1	6-400
<b>Placing Burst Plates with Secondary Relief valves</b>	\$ 1000 - \$10 000	11.5 ton	0-1	87-870
<b>Testing and Repairing Pressure Safety Valves</b>	n.a.	4 ton	3-10	n.a.
<b>Implementing centralized information system</b>	> \$ 10 000	n.a.	n.a.	n.a.

**Table 15: Overview Abatement Options for emissions due to incidents.**

## EMISSION REDUCTION: DETECTION (INCIDENTS)

Abatement Options	Implementation Cost	Methane Reduction (annual)	Payback (Years)	Efficiency Index (\$/ton meth.red.)
<b>Using Ultrasound to Identify Leaks</b>	< \$ 1 000	46 ton	0-1	<22
<b>Installing Excess Flow Valves</b>	> \$ 10 000	0.3 ton	>10	300000
<b>Implementing alarm system</b>	> \$ 10 000	n.a.	n.a.	n.a.
<b>Airborne Leak Detection</b>	> \$ 10 000	n.a.	n.a.	n.a.

**Table 16: Overview Abatement Options for emissions due to incidents.**

## 6 Conclusion

The methane emissions on a natural gas transportation grid can be analysed by grid segment (transportation, compression, storage,...) or by activity (maintenance, incidents and operational processes).

There are different approaches to make emission inventories by the natural gas industry described by the IPCC Guidelines:

- The *Tier 1* method uses aggregate production-based emission factors and national production data <sup>(i)</sup>.
- The *Tier 3* method is a rigorous source specific evaluation, requiring a detailed inventory of infrastructure, and detailed bottom-up emission factors.

### 6.1 Quantification following Tier 1

The main conclusion of this review is that the different methods are showing significant differences in the inventory. The results of the above mentioned analyses illustrate the variety of different approaches.

- Different assignment of gas system elements to gas system segments makes it hard to interpret the values correctly.
- The emission factor values are sometimes expressed in methane mass unit per energy unit, while no specification is given regarding the methane content <sup>(j)</sup> in natural gas.

On the other hand, the five last publications of emission factors are in line with each other. It results in an average emission rate of 0.05% GWh CH<sub>4</sub>/GWh transported natural gas or 4.378 ton CH<sub>4</sub>/km pipeline. The use of emission factors according to IPCC Tier 1 (Top-down approach) is the least reliable approach. Literature data on methane emission factors from natural gas system sources are numerous but usually the description of the emission sources and the conditions under which the factors are valid is not sufficient in order to fully justify the choice of these factors for specific inventory.

Carrying out the inventory relying exclusively on literature values of emission factors (following Tier 1) leads to extremely high uncertainty as they give only single values and does not allow to assess the uncertainty. Based on the Tier 1 results, it is not possible to achieve meaningful conclusions regarding the emission from different natural gas system segments

or to use this as a basis for an emission reduction strategy plan. A Tier 3 approach appears to be indispensable.

### 6.2 Quantification following Tier 3

To make a complete inventory of all gas emitting instruments, it is a time consuming and rigorous work. Emission quantification by instrument may vary extremely between facilities due to differences in design and operating practices. While initially it may be appropriate to use values reported in the general literature, it is better to develop own values, on the basis of technical datasheets and manuals or by reliable measurements. The methodology IPCC Tier 3 (Bottom-up approach) allows a better estimate than the Tier 1 methods surveyed here. The detailed emission quantification allows us to identify the emission sources and to propose abatement options accordingly.

The quantification of methane emissions on a high pressure transportation grid gives as result that the highest emission sources are located at the pressure-control stations, in the operational processes. More than 31% of the total emissions on the grid are due to the use of boosters. Besides, the lowest emission quantities are noted under the section of incidents.

An emission rate of 0.01% GWh CH<sub>4</sub>/GWh transported natural gas or 1.145 ton CH<sub>4</sub>/km pipeline.

This is largely under the mean estimation methods following Tier 1. The report of IGU suggests in that case to evaluate the completeness of methane emission registration. (leak detection, unplanned interventions,...)

### 6.3 Abatement Options

The most beneficial abatement options are those with the best efficiency index (implementation cost/emission reduction). The best reduction solution of each activity is:

***Maintenance emissions:*** Reducing the line pack pressure minimize the amount of natural gas that is vented into the atmosphere during extension works of the network and maintenance activities on pipelines. An integrated management of the grid, evaluating the pressure need at all supply points will save working hours of the compressor units, the regulation at control stations and leads to methane emission savings.

***Operational emissions:*** Replacing high bleed to low bleed devices. The actual bleed rate largely depends on the design of the device. Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment.

(i) There is no Tier 2 method for natural gas systems in the IPCC Guidelines.

<sup>j</sup>The methane content in natural gas can vary from +/- 70mol% to 98mol%

*Compressor emissions:* Avoid depressurizing after unit shut down. Keeping compressors pressurized when they are off-line for operational reasons achieves immediate payback.

*Incidental emissions:*

- Directed Inspection & Maintenance (DI&M) is a cost-effective way to reduce natural gas losses from equipment.
- Using ultrasound leak detectors, like a stethoscope, listen to the unique noise of gas leakage through a valve. Electronics are used to filter out the low frequency noise of compressors and reveal high frequency sounds associated with gas leakage.

A detailed description of all abatement options is enclosed in the Appendix: Abatement Options. Every option has been analyzed on technical / operational, ecological and economical perspectives.

## 7 Recommendations

### 7.1 Sustainable Management

The implementation of a program for lowering the emissions of the greenhouse gases and in particular the methane losses should be integrated as a main part of the policy of each facility.

Such program should be integrated in the Front-end Engineering and Design phases (FEED) for transmission grid, compressor stations, metering and pressure-control station and other gas related facilities, as a start. Next step is to implement such a program in the Engineering, Procurement and Construction details, so that this becomes a standard in the specifications of construction for main-contractors. Furthermore, a sensitization of the operational section of the facility is more than necessary. Procedures, instructions taking into account a favorable methane emission policy for operating, maintaining, inspecting emission sensitive equipment, must be set up. Technicians should become more aware of this subject and acting in a proper way.

### 7.2 Measurement program

The calculation methods and their associated emission factors are different in the diverse countries, and their application to a particular network can yield a broad range of results. The selection of the most suitable procedure for a particular situation is not trivial, and ideally should be based on reliable field data. However, such studies are very expensive and only a few comprehensive studies have been found in the technical literature reporting measurements of the volume of gas

emitted in transportation networks. Therefore, the development of reliable procedures for the quantification of methane emissions in a particular grid is still an open issue needing further efforts, especially regarding field measurements. It would be useful to develop a measurement program, to critically oversee its implementation and to use the results of measurements and operational data to estimate the emissions.

### 7.3 Actualisation Activity Factors

Ideally, emission estimates should be prepared for the reference year and subsequent years using the same method. Where some historical data are missing it should still be possible to use source specific measurements combined with back casting techniques to establish an acceptable relationship between emissions and activity data in the reference year. Approaches for doing this will depend on the specific situation. Where changes in methods and emission factors are substantial, the whole time series should be recalculated and reported in a transparent manner (IPCC, 2001).

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