CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 02 - in effect as of: 1 July 2004)

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Metrogas Package Cogeneration Project
Version 2
Date: 2 March 2006

A.2. Description of the project activity:

With offices in Santiago, Chile, Metrogas S.A. is a company that distributes natural gas to residential, commercial, and industrial consumers, as well as some to transportation. The proposed project[1] involves the installation of a "package" cogeneration system that would consume natural gas and sell electricity and heat to an industrial plant, by the project sponsors —Metrogas. Metrogas does not own or operate the industrial plant. Through the package cogeneration system, Metrogas sells heat and electricity to a plant of Watt's Alimentos S.A., a food company. Metrogas S.A. or a Metrogas subsidiary owns the cogeneration system and retain the rights associated with any emissions reductions (ERs).

Watt's Alimentos S.A. produces and commercializes various foods such as margarine, butter, oil, mayonnaise, marmalade, juice, tomato sauce, ketchup, pasta, etc. This plant, located in metropolitan Santiago, purchases heat and electricity from the cogeneration system installed at the factory premises, so as to reduce the consumption of electricity and natural gas, which are purchased.

By introducing the cogeneration system, the total amount of fossil fuels used to provide electricity and heat to the plant is reduced, resulting in a reduction in CO_2 emissions, of 23,933 tonnes CO_2-equivalent over 10 years.

The project contributes to sustainable development objectives of the Chilean Government (as stated in the Environmental Policy of the Santiago Metropolitan Area developed by CONAMA, http://www.conama.cl/portal/1255/article-26194.html). The project has the written approval of CONAMA for voluntary participation, confirming that the project supports sustainable development (see Annex 5).

Energy efficiency and cogeneration lead to environment, economic and the social benefits. Chilean experiences in improving energy efficiency began in 1993, when the National Program for the Conservation and Rational Use of Energy (CUREN) was developed by the National Energy Commission (CNE, Comisión Nacional de Energía) with support from the European Community. The key objective of this project was to encourage energy efficiency in the industrial, mining, commercial, public and residential sectors. The project called for the performance of energy audits and surveys of energy efficiency potential on a national scale.

The main barriers to energy efficiency identified by the CUREN project are the same as those described in the classical literature on energy efficiency from other countries. They include a basic lack of information on the concept of efficiency and on its technical and economic benefits, as well as on the

---

[1] When the PDD was first drafted in 2003 and submitted for validation, the project had not been implemented. The project —then proposed— is now operational. The current version of the PDD has been revised considering the project status as of early 2006.

modern and efficient technologies currently available on the market; difficulties in securing financing for energy efficiency projects; insufficient economic incentives to develop energy efficiency projects, etc.

For these reasons, although the size of the proposed cogeneration project is relatively small (less than 3 MWe), it is certain that project implementation would provide useful experience encouraging replication on a larger scale, which would lead to a diversification of the generation sources with reduced GHG emissions compared to the baseline.

A.3. Project participants:

Name of Party involved (*). ((host) indicates a host Party)	**Private and/or public entity(ies) project participants (*) (as applicable)**	**Kindly indicates if the Party involved wishes to be considered as project participant (Yes/No)**
Chile (host)	Metrogas S.A. Private entity. Project Developer.	No
Japan	Electric Power Development Co., Ltd. Private entity. Annex I country participant.	No

(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.

See Contact Information in Annex 1 to this PDD.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Chile

A.4.1.2. Region/State/Province etc.:

Santiago

A.4.1.3. City/Town/Community etc:

San Bernardo

A.4.1.4. Detail of physical location, including information allowing the unique identification of this project activity (maximum one page):

The cogeneration system is located in the Watt’s San Bernardo plant, located in the southern side of metropolitan Santiago area, as depicted in Figure 1.

San Bernardo

Figure 1 Santiago metropolitan area, showing location of San Bernardo.

A.4.2. Category(ies) of project activity:

Sectoral Scope 4. Manufacturing industries

Demand side energy efficiency improvement through cogeneration

A.4.3. Technology to be employed by the project activity:

The project involves the installation, by the project sponsors —Metrogas— of a “package” cogeneration system that consumes natural gas and sells electricity and heat to an industrial plant. Metrogas does not own or operate the industrial plant. Through the package cogeneration system, Metrogas sells heat and electricity to a plant of Watt’s Alimentos S.A., a food company. Metrogas S.A. owns the cogeneration system.

Prior to project implementation there were four steam boilers in Watt’s Alimentos S.A., but only three (Superior, Cleaver Brooks and Salcor —see table below) operated continuously, using natural gas as fuel:

Technical characteristics of the boilers

Manufacturer	Superior Combustion	Wagner	Cleaver	Salcor
Serial No.	2940	7477	OLO 95.808	330
Year of manufacture	1963	1978	1996	1976
Fuel used	Natural gas/Diesel #2	Diesel #2	Natural gas/Diesel #2	Natural gas
Type	Fire tube	Fire tube	Fire tube	Fire tube
Maximum operating pressure	8.5 kg/cm^2	12.0 kg/cm^2	14 kg/cm^2	12 kg/cm^2
Steam production rate	7,000 kg/h	3,000 kg/h	12,519 kg/h	10,000 kg/h
Fuel consumption rate	420-460 kg/h	170 kg/h	660-810 kg/h	590 kg/h
Heating surface	282 m^2	120 m^2	325.2 m^2	250 m^2
Firebox diameter	1.00 m	0.8 m	1.143 m	1.2 m
Firebox length	5.00 m	3.3 m	6.045 m	47.40 m

Equipment	Natural gas consumption EPA 5 (1)		Diesel consumption EPA 5 (1)	Average of combustion efficiency (1)	Efficiency technical boilers (2)	Power technical net base HHV	Steam production isokinetic base	SNS (3) serial #	Manufacturer year
	kg/h	Nm^3/h	kg/h	%	%	Mcal/h	tonne/h		
Superior	527.4	732.5	------	81.2	79.2	6,593	9,237	599	1963
Cleaver Brooks	701.1	973.7	------	73.4	81.4	8,764	12,612	1768	1996
Salcor	423.1	587.6	------	54.6	52.6	5,289	4,918	2050	1996
G. Wagner	------	------	171.0	82.9	80.9	1,864	2,668	527	1978
						Total	2,9436		

(1) Source: Isokinetic sampling required by the Metropolitan Service of Environmental Health (Servicio de Salud Metropolitano del Ambiente).

(2) 2% is discounted due to losses in purges and radiation to the outside.

(3) National Health Service (Servicio Nacional de Salud).

Prior to project implementation, the fourth boiler, which is Wagner brand and diesel-fired (with a real capacity of 2.8 ton steam/hour) operated only on Sundays whereas, on week days, the three natural gas fired boilers usually operated with a maximum capacity of 26 tonnes of steam/hour. The natural gas fired boilers have modulating burners which allow to regulate the fuel in a wide range of load (minimum 20-100%). This keeps efficiency values constant for lesser levels of load. Subsequent to the installation of the cogeneration system, one of the boilers, Salcor, is no longer used.

The table above shows the efficiency values of combustion obtained during the annual sampling required by the local environmental authority (SESMA). This information was used to estimate the boiler efficiency discounting 2% of losses (mainly accounted for purges and radiation to the outside). Considering only natural gas boilers, that are the ones that were usually operated, we obtained a calculated efficiency of 75% of higher heating value and 83% of lower heating value. These values were corrected in proportion to the Natural Gas higher heating value and the lower one, which are 9,400 kcal/m^3 (higher) and 8,400 kcal/m^3 (lower), respectively.

Watt's Alimentos steam demand varies, with an average of 13 ton/hour and a maximum of 20 ton/hour. The number of boilers on was decided upon the production plan. Usually the three natural gas fired boilers operated.

Typically, electricity is produced in power plants, and when these are thermal power plants, the heat generated is often wasted. On the other hand, industrial and other heat demand is often supplied by burning a fuel in a boiler or furnace. Cogeneration involves the simultaneous production of electricity and useful heat using a single fuel source. In a cogeneration system, a fuel is burnt to generate electricity, while the residual heat is applied to meet some thermal demand close to the plant. Such a process allows fuel savings with respect to the separate production of electricity and heat in different processes.

There are many different possible technologies applicable to cogeneration, using a variety of liquid, gaseous or even solid fuels. The proposed project is based on a gas engine using natural gas. Based on a relatively clean burning fuel, with low carbon content, this technology simultaneously provides benefits as far as local air pollution as well as helping to mitigate climate change.

There is a great deal of experience with cogeneration systems in Annex I countries, especially Japan. However, there is relatively little experience in most non-Annex I countries, including Chile. There are a number of technological barriers to the implementation of cogeneration systems in Chile. One barrier, the availability of natural gas, has been overcome in Chile in recent years, but others remain. The proposed project, which involves developing engineering and operational skills for local engineers, represents an important opportunity to build local know-how.

While the proposed project is relatively small (below 3 MW_e), its implementation would provide useful experience that would promote replication in other projects, including some of larger scale.

The cogeneration plant comprises two caterpillar engines, one G3520C (1917 kW) and the other G3516B (1032 kW), with a nameplate electric capacity of 2.94 MW_e and an effective capacity of 2.63 MW_e. The basic information for the cogeneration system is given below.

Table 1: Cogeneration system characteristics

Equipment make and model	Caterpillar G3520C Caterpillar G3516B
Net electric output under site conditions 3520C	1917 kW_e
Net electric output under site conditions 3516B	1032 kW_e
Total Net electric output under site conditions	2.94 MW_e
Average useful electricity power output in project	2.63 MW_e
Heat recovery rate	8.74 million Btu/hour (7.78 GJ/h)
Natural gas consumption rate	24.73 million Btu/hour (26.1 GJ/year) lower heating value basis
Expected operation	7,488 hours per year
Expected electricity generation	19,693 MWh / year

The cogeneration project does not consider any modification to boilers being used at Watt's. Following implementation, the cogeneration project was expected to produce 2.2 ton/h of steam and the three natural gas boilers would be operating to produce an average of 10.8 ton/h. There should exist no variation in the future efficiency of boilers since they will reduce their production only by 17% (2.2 out of 13), which would not affect efficiency due to modulating burners.

Typically, prior to project implementation, Watt's consumed an average of 13 ton/h of steam and the cogeneration project was expected to supply a maximum of 2.2 ton/h (17 %).

A.4.4. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

>>

The cogeneration system provides electricity and heat to an industrial facility which needs to purchase less electricity from the power grid and less natural gas to generate heat. Considering the emissions factors of GHGs with and without the cogeneration system, there is a substantial reduction in GHG emissions. In this case, this is a result of two factors: (a) there is improved efficiency of fuel use through the cogeneration system, and (b) electricity cogenerated by burning natural gas offsets electricity supply from the grid.

GHG emissions from project implementation are calculated in later sections of this PDD. The total estimated emission reduction for the project activity is 23,933 t-CO_2 (in ten years)

These reductions are a consequence of project activity that would not have occurred anyway, because of a number of barriers, both technological and institutional. These barriers are described in Section B.3.

A.4.4.1. Estimated amount of emission reductions over the chosen crediting period:

The *ex-ante* emissions reductions are estimated to be 23,933 tonnes CO_2-equivalent over 10 years. Note that actual emissions reductions will be based on monitored data and may differ from this estimate.

Year	Annual estimation of emission reductions (tonnes of CO_2 e)
2005	2,393.3
2006	2,393.3
2007	2,393.3
2008	2,393.3
2009	2,393.3
2010	2,393.3
2011	2,393.3
2012	2,393.3
2013	2,393.3
2014	2,393.3
Total estimated reductions (tonnes of CO_2e)	23,933
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	2,393.3

A.4.5. Public funding of the project activity:

No funds from public national or international sources are involved in any aspect of the proposed project.

SECTION B. Application of a baseline methodology

B.1. Title and reference of the approved baseline methodology applied to the project activity:

The approved baseline methodology AM0014 *"Natural gas-based package cogeneration"* is applied in order to construct the baseline scenario, to demonstrate project additionality and to estimate the corresponding emission reductions.

B.1.1. Justification of the choice of the methodology and why it is applicable to the project activity:

The industrial plant, where the proposed cogeneration system is to be installed, is a food plant. Prior to project implementation, the plant purchased electricity from the power grid, and purchased fuel (natural gas) to meet the plant's heat requirements. The project involves the installation, by the project sponsors, which is not the industrial plant, of a "package" cogeneration system which consumes natural gas and sells electricity and heat to the industrial plant. The baseline emissions are those that are avoided or offset at the industrial facility because of the heat and electricity supplied by the cogeneration system. Prior to project implementation, the fuel used by the industrial plant was natural gas, which is also the fuel used in the cogeneration system. Thus, the project involves the use of natural gas. The methodology selected is specifically designed for package cogeneration system using natural gas.

B.2. Description of how the methodology is applied in the context of the project activity:

The cogeneration system is not sized to meet all of the heat or electricity requirements of the plant. Rather, only the base load of heat and electricity would be provided, implying a fairly continuous operation of the cogeneration system over most of the hours in the year, corresponding to plant operation.

The baseline methodology is applied in two ways.

The first procedure to estimate baseline emissions, the heat and electricity output rates of the cogeneration system are multiplied by an estimate of annual operating hours. These emissions estimates also require specifying the efficiency of the industrial boiler whose heat output is to be substituted by output from the cogeneration system. An *upper* limit of efficiency is taken to be the most conservative estimate. The higher the efficiency the lower is the natural gas consumption and associated emissions in the baseline. The resulting *a priori* estimates values are presented in this PDD, and also used to estimate emission reductions.

The second procedure is applied in the monitoring procedure, and forms the basis for determining project and baseline emissions, and reductions, from actual measurements. In this case, rather than estimating annual operating hours of the cogeneration system, baseline emissions are determined by actual, monitored heat and electricity supplied by the cogeneration system and to the industrial facility. The reduced natural gas consumption of the industrial boiler is determined by a boiler efficiency that is measured periodically.

The main difference between the procedures for the *a priori* estimates and the actual, monitored estimates is in how the heat and electricity output of the cogeneration system are determined. Emissions factors and all other parameters remain unchanged in the two procedures.

Parameters and data sources for the first procedure are shown below. The details of the calculation procedure and results, using this procedure, are shown in Annex 3.

Parameters	Data sources
Industrial Boiler Efficiency-(**e_b**)	Highest value obtained from measurements performed by Metrogas S.A.
Lower heating value -(**CV_{NG}**)	For natural gas in Chile. Value provided by Metrogas.
CO_2 emissions factor (combustion)-(**EF_{NG}**)	Ref. 1, Table 1-1 pag 1.13. Natural gas (dry): 15.3 t C/TJ lower heating value basis. X 44/12 = 56.1 t CO2/TJ.
N_2O emissions factor (combustion)-(***NEF***)	Ref. 1, Table I-19 page 1.57. Natural gas boiler.
Global Warming Potential (N_2O)-(**$GWP\ (N_2O)$**)	
CH_4 emissions factor (combustion)-(***MEF***)	Ref. 1, Table I-16 page 1.54. Natural gas boiler.
CH_4 emissions factor (natural gas production and pipeline leakage)-(***MLR***)	Sum of above two emissions factors.
Global Warming Potential (CH_4)- (**$GWP\ (CH_4)$**)	Ref. 2, for methane this was 21.
Baseline emission factor from electricity-(**BEF_{elec}**)	Estimated with data from Operational Statistics, ”Anuario 2004” (www.cdec-sic.cl)

Variables	Data sources
Energy input rate (lower heating value basis)-(***EIRcog***)	Metrogas S.A.
Cogeneration Heat output rate (total)-(***CHOR***)	Metrogas S.A.
Electric power output-(***CPO***)	Metrogas S.A.
Annual operating hours-(***AOH***)	Metrogas S.A.
Boiler fuel use offset by cogen heat output-(***ABECNG***)	Metrogas S.A.
Cogeneration capacity-(***CPO***)	Metrogas S.A
Cogeneration electric output-(***CEO***)	Calculated with ***CPO*** and ***AOH***.

References
1) IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Volume 3 (1996).
2) According to Article 5, section 3 of the Kyoto Protocol, GWP value is as agreed on at COP3.

The second procedure, to be used for determining and documenting project and baseline emissions, and emissions reductions, form part of the monitoring and verification protocol. Parameters and data sources are given in the table below, while the procedure is described in Annex 4.

Parameters	Data sources
Lower heating value -(***CV_{NG}***)	For natural gas in Chile. Value provided by Metrogas.
CO_2 emissions factor (combustion)-(***EF_{NG}***)	Ref. 1, Table 1-1 pag 1.13. Natural gas (dry): 15.3 t C/TJ lower heating value basis. X 44/12 = 56.1 t CO2/TJ.
N_2O emissions factor (combustion)-(***NEF***)	Ref. 1, Table I-19 page 1.57. Natural gas boiler.
Global Warming Potential (N_2O)-(***GWP (N_2O)***)	
CH_4 emissions factor (combustion)-(***MEF***)	Ref. 1, Table I-16 page 1.54. Natural gas boiler.
CH_4 emissions factor (natural gas production and pipeline leakage)-(***MLR***)	Sum of above two emissions factors.
Global Warming Potential (CH_4)- (***GWP (CH_4)***)	Ref. 2, for methane this was 21.
Baseline emission factor from electricity-(***BEF_{elec}***)	Estimated with data from Operational Statistics, "Anuario 2004" (www.cdec-sic.cl)

Variables	Data sources
Annual consumption of natural gas in the cogeneration system-(***AFC_{NG}***)	Metrogas S.A.
Cogeneration Heat output rate (total)-(***CHOR***)	Metrogas S.A.
Cogeneration electric output-(***CEO***)	Metrogas S.A.
Industrial Boiler Efficiency-(***e_b***)	External laboratory contracted by Metrogas S.A. to meet annual inspection requirements for industrial boilers in Chile.

B.3. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity:

The proposed project is additional, insofar as it faces and would need to overcome a number of barriers: (a) technological barrier, (b) institutional barrier A, and (c) institutional barrier B. Tests for determining additionality considering these barriers are provided following the approved methodology as described above.

Once additionality is determined, the project and baseline scenarios correspond to the cases where the proposed package cogeneration system is or is not installed.

Estimates of project and baseline emissions are determined as shown in Annex 3. Considering a 10-year project lifetime, the values are summarized below:

Table 2: Estimates of emission reductions

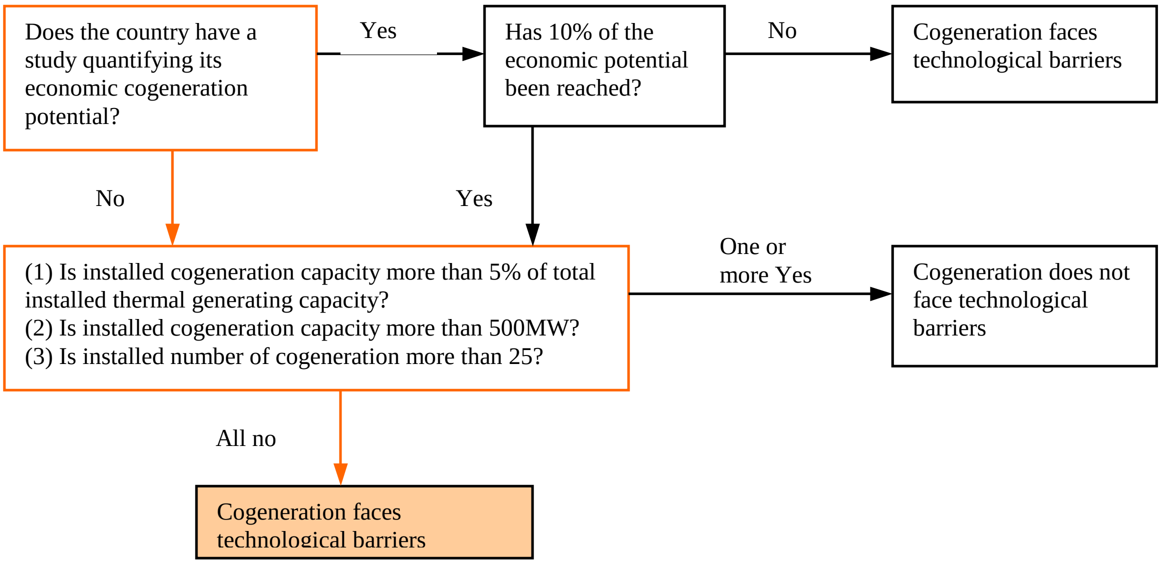
Baseline emissions	143,141	tonne CO_2-equiv
Project emissions	123,357	tonne CO_2-equiv
Emissions reductions	23,933	tonne CO_2-equiv

Thus, project implementation implies a reduction in GHG emissions with respect to the baseline of 23,933 tonnes of CO_2 equivalent.

A number of important barriers have prevented and continue to prevent the implementation of cogeneration projects in Chile. These are described as follow:

(a) Technological barrier.

AM0014 Additionality test 1 is applied by following the flow chart below. A low market share of cogeneration means that there is insufficient infrastructure to support installation and maintenance of such systems, acting as a technological barrier to project participants:



The proposed technology, installing a cogeneration system to provide heat and electricity to an industrial plant is technologically advanced alternative to the current practice of purchasing electricity and purchasing fuel to produce heat for industrial requirements. While industrial cogeneration has a significant presence in some industrialized countries, this is not the case in most developing countries, including Chile, where there are virtually no cogeneration systems in operation. The new technological alternative implies additional risk with respect to operation and performance, compared to the business-as-usual existing technology.

Cogeneration systems established in Chile

In Chile, although there has been natural gas in the Southern region for more than 20 years and in the central region since 1997, only two cogeneration units have been installed.

- Nestlé Chile, Ice cream Plant: This is a 1 MW equipment that was set up in 1998 and is located in the Metropolitan Region. This plant cannot amortize its financing with its savings. Its primary objective was to ensure its electric supply in a crisis year by applying a solution similar to a European one without further consideration of financial analysis.

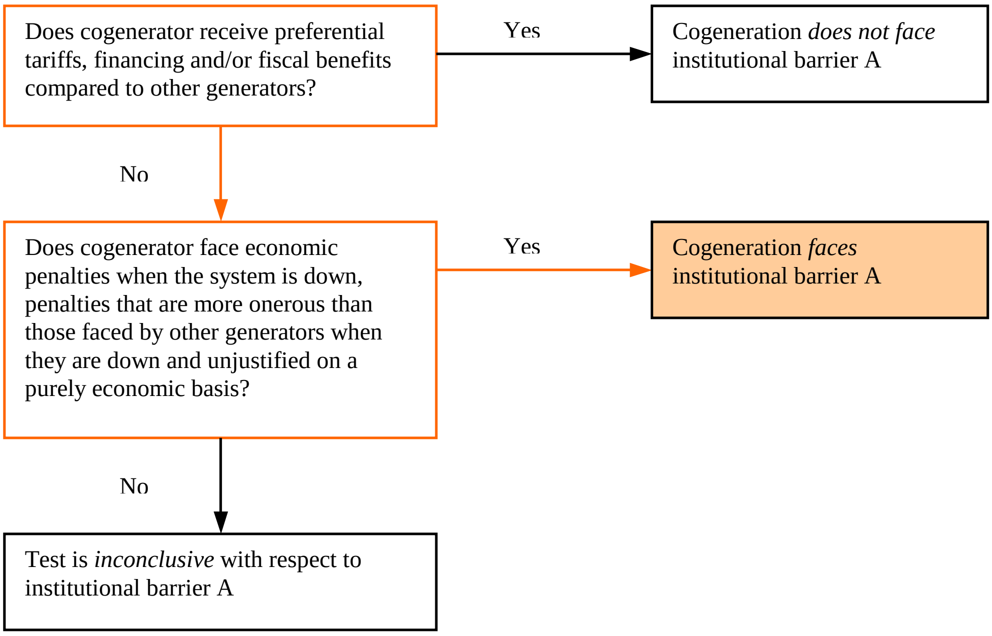
- Tapihue Plant: It is located in Casablanca, in a suburban region and away from the Metropolitan Region. This is a 6 MW plant installed by the electricity distribution company of the region, Chilquinta, in an attempt not to reinforce its local faulty distribution network.

> Chilquinta uses all of the electric energy produced to feed its distribution network and to sell steam to a nearby company. Therefore, this project should be considered as one of distributed generation instead of a cogeneration one.

Is it the normal practice in the industrial sector, to buy power and heat separately? In Chile there is no company that supplies thermal and electric energy simultaneously. None of the Metrogas 400 industrial customers and 9,000 commercial customers purchases both thermal and electric energy from the company, they do it separately.

(b) Institutional barrier A (Institutional barriers to cogeneration in the power system operation).

AM0014 Additionality test 2A is applied by following the flow chart below. Following the approved methodology a serious barrier may be present, especially in deregulated power systems. All electricity users may have to pay the maximum demand charge for the whole year. Thus, when the cogeneration system is not operating (due to routine maintenance or forced outage), the user of electricity would have to purchase the electricity from the power grid. While this period may be small, the purchase may involve paying for the power demand (kW) for the whole year. This is a significant penalty for users of cogeneration systems.



There may be financial and fiscal barriers to cogeneration. While in Chile, cogenerators have access to the transmission network, they face a significant cost penalty. Specifically, when the cogeneration system is not operational (and all equipment needs maintenance), the purchaser of cogenerated electricity needs to purchase electricity from the grid. A technical problem that requires shutting down the cogeneration system for even 15 minutes means not only that the power user pay for the electricity (kWh) consumed during this period, but also for the maximum power demand (kW) for the entire billing period. Moreover, while the billing period is monthly, the billed peak demand remains at the maximum demand for 12 months at a time. Thus, if the cogeneration system is not operational even for a short period of time every year, the industrial user must pay the maximum demand charge all year long.

Although, this could not be the case for package cogeneration system, as they are only providing part of the electricity for the purpose to use within the factory and for selling to the grid, another important aspect that constitute a barrier in installing cogeneration system is that the present electricity law does not require the grid to purchase excess energy produced by the cogenerator, and even the local electric distribution company might place significant barriers to the operation. The latter is because there are no regulated prices for electricity transmission.

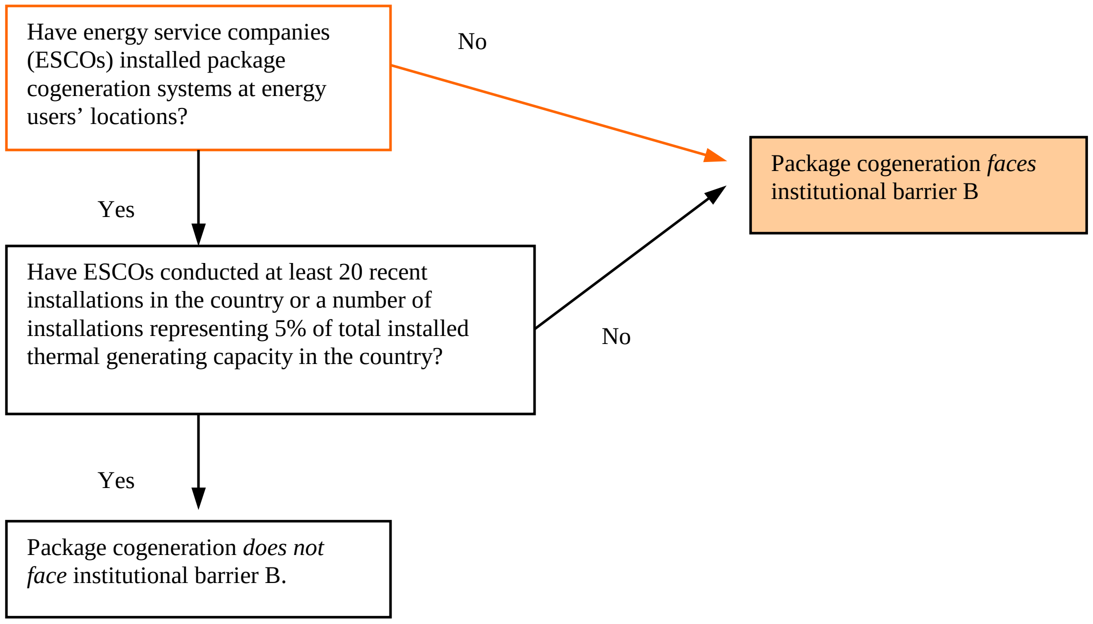
The open market power system of Chile and other countries that underwent power sector reforms in the 1990s favoured competition among power generators, but also represented a significant barrier to cogeneration.

It should be noted that cogeneration receives favourable treatment in those countries where significant amount of cogeneration has been developed. In some countries, e.g. Spain, cogeneration receives a dispatch advantage, whereby cogenerators meeting certain technical standards are at an advantage to export electricity to the grid. Other countries such as Germany subsidize cogeneration through favourable rates for cogenerated electricity. None of these advantages are available to cogeneration in Chile.

(c) Institutional barrier B (Institutional arrangement for investor to sell electricity and **heat** *to an industrial user).*

The traditional practice is for an industrial user to meet their electricity and natural gas demand by purchases from power and gas companies respectively. In a packaged cogeneration system, the institutional arrangement is very different. In this case, the project developer invests in and installs the cogeneration system at the industrial user site, and provides electricity and heat to that user. This institutional arrangement requires project developer to have special management resources and organizational capacity, and for the industrial energy user to accept this arrangement. Where such experience is lacking, promoting the new arrangement involves a significant institutional barrier.

AM0014 additionality test 2B is applied by following the flow chart below.



Prevailing practice is that an industrial user acquires electricity from a power company, and meets its heat requirements by purchasing fuels from fuel suppliers. In the proposed project, a cogeneration system would be installed by a party that is not the industry with electricity and heat demand. This party would invest in the cogeneration system and sell electricity and *heat* to the industrial user. This is called "package" cogeneration and involves a novel institutional arrangement, compared to the traditional practice in which the industrial plant purchases electricity and fuel from the electricity and gas companies respectively. Since the arrangement is new, there is no experience with respect to managerial resources and organizational capacity. These represent a significant institutional barrier faced by the proposed project.

As a result, in the absence of the CDM, the proposed project would not be implemented, and these emissions reductions would not take place.

Through the sale of GHG credits, the project sponsor Metrogas S.A. expected to mitigate the barriers to and risks associated with project implementation. Metrogas S.A. is interested in exploring the CDM alternative as one way of helping to pay for environmental projects that would not otherwise be possible. This is the first project submitted by Metrogas S.A. to CDM.

B.4. Description of how the definition of the project boundary related to the baseline methodology selected is applied to the project activity:

The project activity consists of the installation of a cogeneration system whose input is natural gas from the gas pipeline, and the outputs are electricity and heat supplied to an industry with demand for heat and electricity. Although the project is installed at the industrial site, the project boundary is strictly the cogeneration system.

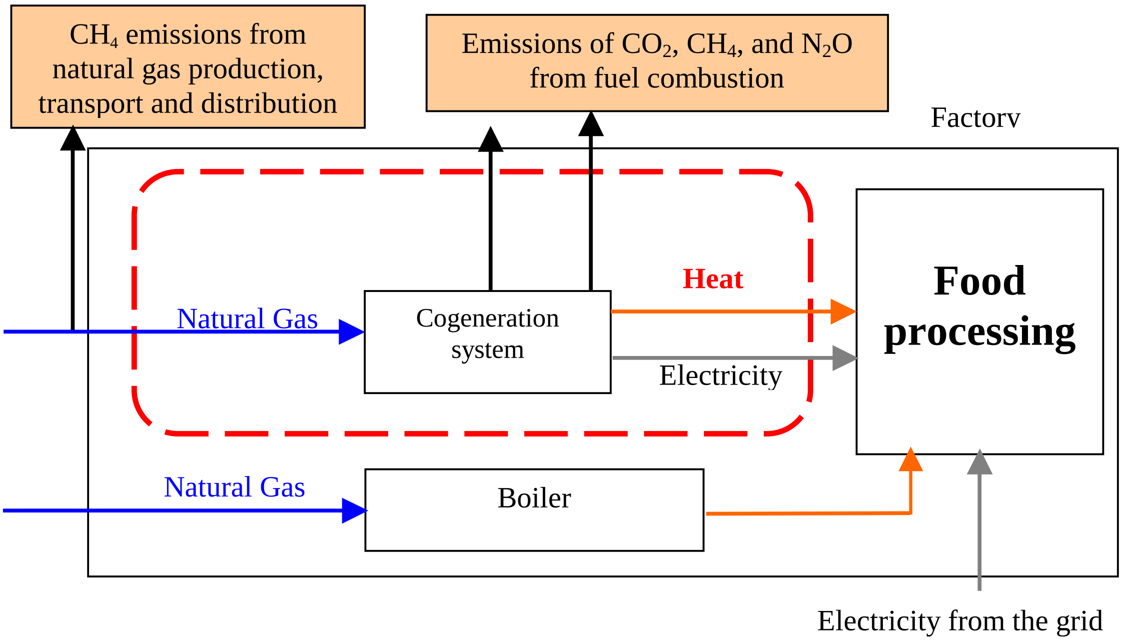


Figure 2. Project boundary for natural gas fired package cogeneration system

The cogeneration system is sized to provide base load electricity and heat to the industrial plant. Thus, the system does not meet all of the heat or electricity demand of the plant.

Prior to project installation, and in the absence of the project, the industry acquired all of its electricity from the power grid and met all of its heat requirements with natural gas acquired from the pipeline.

Once the project (cogeneration system) was installed, the plant acquires heat and electricity from the system to meet *some* of its heat and electricity needs. The remaining electricity demand is met by acquisition from the power grid. Similarly, the remaining heat demand is met by boilers and furnaces at the plant that operate with natural gas acquired from the pipeline.

Thus the baseline is determined by the electricity and fuel purchases by the industrial plant from the electricity grid and the natural gas pipeline, that are avoided or offset as a result of electricity and heat supplied from cogeneration system to the industrial plant located at the project site, *but outside the project boundary*.

By defining the project boundary as we propose here, we are only concerned by the impact of the cogeneration system on emissions.

This definition of the project boundary makes sense for several reasons:

1. The project emissions depend entirely on gas input to the cogeneration system, while emissions avoided (baseline emissions) can be determined from heat and electricity produced by the cogeneration system and used at the factory. Thus we need only to estimate emissions associated with natural gas consumption of the cogeneration system, and the emissions avoided at the industrial plant, because of the heat and electricity output of the cogeneration system. The associated monitoring determines both project and baseline emissions. Other fuels used at the factory and additional electricity used at the industrial plant are irrelevant. Specifically, natural gas and electricity consumption at the factory prior to the installation of the cogeneration system are irrelevant.

2. The “financial boundary” is the same as our definition of the project boundary. The project sponsors (Metrogas Chile and others) invest in the cogeneration system, which is within the project boundary. They then acquire natural gas for use in the cogeneration system and provide heat and electricity to its client, the factory, outside the project boundary.

Going back to the definition, Marrakesh Accords define “project boundary” as follows[2]*:*

> “52. The project boundary shall encompass all anthropogenic emissions by sources of greenhouse gases under the control of the project participants that are significant and reasonably attributable to the CDM project activity.”

As described above, in a ‘package cogeneration’ situation, the project participant owns and operates the proposed cogeneration plant. The rest of the industrial plant is not under the control of the project

---

[2] Decision 17/CP.7 Modalities and procedures for a clean development mechanism as defined in Article 12 of the Kyoto Protocol, ANNEX: Modalities and procedures for a clean development mechanism, G. Validation and registration, 52, Marrakesh Accord, 10 November 2001.

participant. This could be applied even if parameters need to be monitored outside the project boundary in order to determine project emissions. Thus, the carbon content and calorific value of the fuels, involved in industrial boiler(s) and the fuel efficiency of the boiler(s) are key parameters, but, according to the Marrakesh definition, it cannot be considered to be within the project boundary. By the same argument, power plant specific fuel consumption, carbon content of fuel used for electricity generation, are all key parameters but not under the control of the project participants and therefore, cannot be considered to be within the project boundaries.

B.5. Details of baseline information, including the date of completion of the baseline study and the name of person (s)/entity (ies) determining the baseline:

Detailed baseline information is provided in Annex 3 to this PDD.

Date of completion of the current version of the baseline study: October 2005.

Baseline study prepared by

Mr. Natsuki Tsukada, MGM International, Ltda. (not a project participant).
Tel: +1-305-433-7540, e-mail: ntsukada@mgminter.com

Dr. Gautam Dutt and Ing. Ignacio Barutta, MGM International, Ltda. (not a project participant).
Tel. (54 11) 5219-1230
e-mail: gdutt@mgminter.com; ibarutta@mgminter.com

SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

The project activity has initiated in May 2004.

C.1.2. Expected operational lifetime of the project activity:

10y-0m

C.2 Choice of the crediting period and related information:

C.2.1. Renewable crediting period

NOT SELECTED.

C.2.1.1. Starting date of the first crediting period:

C.2.1.2. Length of the first crediting period:

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/01/2005.

C.2.2.2. Length:

10y-0m

SECTION D. Application of a monitoring methodology and plan

D.1. Name and reference of approved monitoring methodology applied to the project activity:

As the proposed monitoring methodology has been approved under the name of *“Natural gas-based package cogeneration”* and designated “AM0014” as of September 2004, we will apply this.

D.2. Justification of the choice of the methodology and why it is applicable to the project activity:

The monitoring methodology has been designed specifically for this type of project: Package cogeneration using natural gas.

The document “Monitoring and Verification Plan” of this project presents the methods for collecting data, estimating GHG emissions reduction, and maintaining the documents to support monitoring and verification of the Project GHG emissions. A customized procedure was developed in the form of the Project GHG emission electronic worksheets, which must be used by project implementers and operators —Technical Department of Metrogas S.A.— and complement the instructions presented in the MVP document.

Considering the project boundary, the following data need to be monitored in order to estimate project and baseline emissions, and emissions reductions:

- Natural gas used by the cogeneration system, m^3
- Net electricity supplied by cogeneration system to factory, MWh
- Cogeneration heat output supplied by cogeneration system to factory, GJ

The above three parameters are monitored continuously while being recorded once a month.

Besides these monitored data, we need to estimate methane and nitrous oxide from natural gas combustion in the cogeneration system, using a standard emissions factor. We also need to estimate emissions from natural gas production and pipeline leakage (internal and external to project site), again using a standard emissions factor.

D.2. 1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:								
ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1 - AFC_{NG}	Volume of natural gas consumed*	*Metrogas*	m^3	*M*	*month*	*100%*	Paper (field record) Electronic (spreadsheet)	See below.
2 -CEO	Cogeneration electricity supplied to industrial plant	*Metrogas*	MWh	*M*	*month*	*100%*	Paper (field record) Electronic (spreadsheet)	
3 - *CHOR*	*Cogeneration heat supplied to industrial plant*	*Metrogas*	GJ	*M*	*month*	*100%*	Paper (field record) Electronic (spreadsheet)	

*Note: Volume of natural gas measured is usually adjusted for calorific value. Thus, m^3 of natural gas reported here correspond to equivalent m^3 considering gas with a lower calorific value of 8,407 kcal/m^3.

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

Project emissions of GHG within the project boundary correspond to natural gas consumed by the cogeneration system. These comprise the following items:

a) Carbon dioxide (CO_2) emissions from natural gas combustion;

b) Methane (CH_4) emissions from natural gas combustion; and

c) Nitrous oxide (N_2O) emissions from natural gas combustion.

Each of these emissions may be expressed as the product of an emissions factor and natural gas energy consumption by the cogeneration system.

Once the project is implemented, natural gas energy consumption is determined from monitored natural gas consumption as follows:

Annual natural gas energy consumption in the cogeneration system, AEC_{NG} **(GJ/year)** is given by:

$$AEC_{NG}\ (GJ\,/\,year) = \frac{AFC_{NG} \cdot CV_{NG} \cdot 4.1868\ J/cal}{10^6} \qquad \textbf{(Eq. D.1)}$$

where AFC_{NG} = annual consumption of natural gas (m^3/year)
CV_{NG} = lower heating value of natural gas (kcal/m^3)

Once the natural gas energy consumption has been determined from monitoring, each component of emissions may be estimated as described below:

a) Carbon dioxide (CO_2) emissions per year from natural gas combustion in the cogeneration system

CO_2 emissions from natural gas combustion in the cogeneration system, E_{cs} **(tonne CO_2/year)** are given by:

$$E_{CS}\,(tonne\ \ CO_2\,/\,year) = \frac{AEC_{NG} \cdot EF_{NG}}{10^3} \qquad \textbf{(Eq. D.2)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)
EF_{NG} = CO_2 emission factor of natural gas (kg CO_2/GJ, *lower* heating value basis)

b) Methane emissions (CH_4) from natural gas combustion

A certain amount of methane is generated in the combustion of natural gas. Emissions are estimated using formulae described below:

Methane emissions from natural gas combustion, $E_{met\ comb}$ (tonne CH_4/year), are given by:

$$E_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{AEC_{NG}\cdot MEF}{10^6} \qquad \textbf{(Eq. D.3)}$$

; = annual natural gas energy consumption (GJ/year)
methane emission factor for natural gas combustion (kg CH_4/TJ, *lower* heating value basis)

Convert to units of carbon dioxide equivalent emissions, $E_{equiv\ met\ comb}$ (tonne CO_2 equiv/year)

$$E_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = E_{met\ comb}\cdot GWP\,(CH_4) \qquad \textbf{(Eq. D.4)}$$

where GWP (CH_4) = global warming potential of methane = 21

c) Nitrous oxide (N_2O) emissions from natural gas combustion

A certain amount of nitrous oxide is also generated in the combustion of most fuels. Emissions are estimated using formulae described below:

Nitrous oxide emissions from combustion, *EN_2O comb* (tonne N_2O/year), are given by:

$$E_{N_2O\ comb}\ (tonne\ N_2O\,/\,year) = \frac{AEC_{NG}\cdot NEF}{10^6} \qquad \textbf{(Eq. D.5)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)
NEF = N_2O emission factor of natural gas (kg N_2O/TJ, *lower* heating value basis)

Convert to units of carbon dioxide equivalent emissions, $E_{equiv\ N2O\ comb}$ (tonne CO_2-equiv/year):

$$E_{equiv\ N_2O\,comb}\ (tonne\ CO_2 - equiv\,/\,year) = E_{N_2O\ comb}\,(tonne\ \ N_2O)\cdot GWP\,(N_2O) \qquad \textbf{(Eq. D.6)}$$

where $GWP\ (N_2O)$ = global warming potential of N_2O = 310

Project emissions *E* (expressed in tonnes of CO_2 equivalent per year, tCO_2e/yr) are given by the sum of the emissions determined above:

Project emissions, *E* (tonne CO_2/year), are given by:

$$E = E_{CS} + E_{equiv\ met\ comb} + E_{equiv\ N_2O\ comb}$$

(Eq. D.7)

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :								
ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

The project boundary only includes the proposed cogeneration system. Thus, in the baseline case, there are no emissions within the project boundary. However, as a result of project activities there are changes in emissions outside the project boundary, at the factory, as a result of heat and electricity supplied by the cogeneration system. These emissions comprise the baseline emissions avoided as a result of project activity. However, as we shall see in section E, estimating these emissions does not require monitoring additional data. These emissions are estimated from data monitoring listed in section D.2.1.1, and parameters that remain unchanged by project activities. The procedures for calculating these emissions are described in detail in D.2.1.4 and applied in Section E to this specific project.

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

Baseline GHG emissions correspond to those emissions that are offset by heat and electricity output from the cogeneration system, supplied to the industrial plant.

Since the project boundary is the proposed cogeneration system, there are no emissions within the project boundary in the baseline case. Baseline emissions comprise the following five components:

a) **CO_2 combustion**. CO_2 emissions from combustion, corresponding to the natural gas that would have been used if the cogeneration system did not provide heat to the factory.

b) **CH_4 combustion.** CH_4 emissions from natural gas combustion in the industrial boiler to produce heat that is offset by heat supplied by the cogeneration system.

c) **N_2O combustion**. N_2O emissions from natural gas combustion in the industrial boiler to produce heat that is offset by heat supplied by the cogeneration system.

d) **CH_4 leaks**. CH_4 emissions from natural gas production and leaks in the pipeline supplying natural gas to the factory, associated with the natural gas consumption identified in item (a) above.

e) **CO_2 electricity**. CO_2 emissions associated with the electricity that would have to be purchased from the power grid if the cogeneration system did not provide electricity to the factory.

The first four components of baseline emissions are proportional to natural gas consumption offset by the heat output of the cogeneration system.

Annual baseline natural gas energy consumption offset by heat output from the cogeneration system, $ABEC_{NG}$ (GJ/year), is given by the formulae described below:

Natural gas consumption, $ABEC_{NG}$ (tonne CO_2/year), is given by:

$$ABEC_{NG}\ (GJ/year) = \frac{CHOR \cdot AOH}{e_b} \qquad \textbf{(Eq. D.8)}$$

where $CHOR$ = cogeneration system heat output rate (GJ/h), and
AOH = Annual operating hours (h/year), and
e_b = boiler efficiency.

The value of ***CHOR*** is taken from the specifications of the cogeneration equipment. The value of ***AOH*** is determined from an engineering analysis of the application of the package cogeneration system, and depends on the equipment characteristics as well as the characteristics of the demand for heat and electricity at the industrial plant.

The value of the boiler efficiency at the industrial plant, $\boldsymbol{e_b}$,, is also determined in the engineering study.

a) Baseline carbon dioxide emissions from natural gas combustion, BE_{th} (tonne CO_2/year), are given by (Eq. D.9):

CO_2 baseline emissions, BE_{th} (tonne CO_2/year), are given by:

$$BE_{th}\,(tonne\ CO_2\,/\,year) = \frac{ABEC_{NG}\cdot EF_{NG}}{10^3} \qquad \textbf{(Eq. D.9)}$$

where $ABEC_{NG}$ = annual baseline energy consumption (GJ/year)
EF_{NG} = CO_2 emission factor of natural gas (kg CO_2/GJ, *lower* heating value basis)

EF_{NG} depends on the fuel, and is best determined from national data sources, as indicated in the selected methodology.

b) Baseline methane emissions from natural gas combustion, $BE_{equiv\ met\ comb}$ (tonne CO_2/year), are given by the formulae described below:

Baseline methane emissions, $BE_{met\ comb}$ (tonne CH_4/year), are given by:

$$BE_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG}\cdot MEF}{10^6} \qquad \textbf{(Eq. D.10)}$$

where $ABEC_{NG}$ = annual consumption of natural gas in the baseline (GJ/year)
MEF = methane emission factor for natural gas combustion (kg CH_4/TJ, *lower* heating value basis)

This is converted to units of carbon dioxide equivalent emissions, $BE_{equiv\ met\ comb}$ (tonne CO_2 equiv/year):

$$BE_{equiv\ met\ comb}(tonne\ CO_2 - equiv\,/\,year) = BE_{met\ comb}\cdot GWP\,(CH_4) \qquad \textbf{(Eq. D.11)}$$

where GWP (CH_4) = global warming potential of methane = 21

c) Baseline nitrous oxide emissions from natural gas combustion $BE_{equiv\ N_2O\ comb}$ (tonne CO_2/year), are given by Eq. (D.12) and Eq. (D.13):

Baseline nitrous oxide emissions from natural gas combustion $BE_{N_2O\ comb}$ (tonne CO$_2$/year), are given by:

$$BE_{N_2O\ comb}(tonne\ N_2O/year) = \frac{ABEC_{NG} \cdot NEF}{10^6} \qquad \textbf{(Eq. D.12)}$$

where $ABEC_{NG}$ = annual consumption of natural gas in the baseline (GJ/year), and
NEF = nitrous oxide emission factor for natural gas combustion (kg N_2O/TJ, *lower* heating value basis)

This is converted to units of carbon dioxide equivalent emissions, $BE_{equiv\ N_2O\ comb}$ (tonne CO_2 equiv/year):

$$BE_{equiv\ N_2O\ comb}(tonne\ CO_2-equiv/year) = BE_{N_2O\ comb} \cdot GWP\,(N_2O) \qquad \textbf{(Eq. D.13)}$$

where $GWP\ (N_2O)$ = global warming potential of nitrous oxide = 310

d) **Baseline methane emissions** from natural gas production, pipeline and distribution leaks, $BE_{th\ equiv\ fug}$ **(tonne CO$_2$/year),** are given by Eq. (D.14) and Eq. (D.15):

Baseline methane emissions from natural gas production, pipeline and distribution leaks, $BE_{th\ fug}$ (tonne CH$_4$/year)

$$BE_{th\ fug}(tonne\ CH_4/year) = \frac{ABEC_{NG} \cdot MLR}{10^3} \qquad \textbf{(Eq. D.14)}$$

where $ABEC_{NG}$ is defined as before, and
MLR = methane leakage rate in natural gas production, transport and distribution leakage, including leaks at the industrial site (kg CH_4 /GJ natural gas energy consumption, lower heating value basis).

This is converted to units of carbon dioxide equivalent emissions, $BE_{th\ equiv\ fug}$ (tonne CO_2 equiv/year) using Eq. (D.15).

$$BE_{th\ equiv\ fug}(tonne\ CO_2-equiv/year) = BE_{th\ fug} \cdot GWP(CH_4) \qquad \textbf{(Eq. D.15)}$$

where $GWP\ (CH_4)$ is defined as before.

e) **Baseline emissions of CO$_2$ from electricity supply,** BE_{elec} **(tonne CO$_2$/year),** are determined from the formulae described below:

Baseline carbon dioxide emissions that are offset by electricity supplied by the cogeneration system, BE_{elec} **(tonne CO_2/year),** are given by:

$$BE_{elec}\,(tonne\ \ CO_2\ /\ year) = \frac{CEO \cdot BEF_{elec}}{10^3} \qquad \textbf{(Eq. D.16)}$$

where CEO = cogeneration electricity output (MWh/year)

BEF_{elec} = baseline CO_2 emissions factor for electricity from public supply (kg CO_2/MWh)

To give estimate to $\boldsymbol{BEF_{elec}}$, the CO_2 emissions factor for electricity supply, we need to apply either “Consolidated Baseline Methodology for Zero-emissions Grid-Connected Electricity Generation from Renewable Sources” or “Simplified Methodology for Small-scale CDM Project activities” in case electricity displacing is less than or equal to 15 MW equivalent, as is being described by AM0014. As this cogeneration system consist of less than 15 MW, we apply the latter.

Appendix B of the simplified Modalities and Procedures for small-scale CDM project activities contains two options that can be applied in the selected project category:

“The baseline is the kWh produced by the renewable generating unit multiplied by an emission coefficient (measured in kgCO_2/kWh) calculated in a transparent and conservative manner as:

(a) The average of the “approximate operating margin” and the “build margin”, where:

  (i) The “approximate operating margin” is the weighted average emissions (in kgCO_2/kWh) of all generating sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation;

  (ii) The “build margin” is the weighted average emissions (in kgCO_2/kWh) of recent capacity additions to the system, defined as the lower of most recent 20% of plants built or the 5 most recent plants;

OR,

(b) The weighted average emissions (in kgCO_2/kWh) of the current generation mix.”

Option (a) is selected in this project.

Total baseline emissions, $\boldsymbol{BE_{total}}$ **(tonne CO_2-equiv/year),** are given by Eq. (D.17):

$$BE_{total} = BE_{th} + BE_{equiv\ met\ comb} + BE_{equiv\ N_2O\ comb} + BE_{th\ equiv\ \ fug} + BE_{elec} \qquad \textbf{(Eq. D.17)}$$

D. 2.2. Option 2: Direct monitoring of emission reductions from the project activity (values should be consistent with those in section E).

OPTION NOT SELECTED

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

Not applicable

D.2.3. Treatment of leakage in the monitoring plan

D.2.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project activity

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

In the CDM context, off-site emissions that occur as a result of project activities are called "leakage". For this project (and for the baseline), one such leakage emissions is the fugitive emissions of methane from natural gas production, transport and distribution to the project site. There would also be fugitive emissions from the natural gas distribution network within the project site. We call this *MLR*, and express it in terms of kg methane per GJ of natural gas energy consumption. The formulae for estimating these emissions are given below.

Annual fugitive methane emissions (natural gas production, pipeline and distribution leaks), E_{fug} **(tonne CH_4/year),** are given by:

$$E_{fug}\,(tonne\ CH_4 / year) = \frac{AEC_{NG} \cdot MLR}{10^6} \qquad \textbf{(Eq. D.18)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)
MLR = methane leakage rate (kg CH_4/GJ of natural gas consumption, LHV basis)

Convert to carbon dioxide equivalent emissions, $E_{equiv\ \ fug}$ **(tonne CO_2 equiv/year)**

$$E_{equiv\ \ fug}\,(tonne\ \ CO_2 - equiv / year) = E_{fug} \cdot GWP\,(CH_4) \qquad \textbf{(Eq. D.19)}$$

where $GWP\,(CH_4)$ = global warming potential of methane = 21

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

The emission reductions ER by the project activity are given by:

Emission reductions, ER (tonnes of CO_2 equivalent (tCO_2e/yr)) are given by:

$$ER = BE_{total} - E - E_{equiv\ \ fug} \qquad \textbf{(Eq. D.20)}$$

where

BE are baseline emissions determined in a dynamic manner as explained in section D.2.1.4,
E are project emissions determined as indicated in section D.2.1.2, and
$E_{equiv\,fug}$ are leakage emissions estimated as indicated in section D.2.3.2.

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored		
Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
1	*Low*	These data will be directly used for calculation of emissions reductions
2	*Low*	These data will be directly used for calculation of emissions reductions
3	*Low*	These data will be directly used for calculation of emissions reductions

Metrogas S.A. has certified ISO 9001 (1994). The Manual for Quality Control would include procedures for calibration of the instruments in order to assure quality of the data collected.

D.4 Please describe the operational and management structure that the project operator will implement in order to monitor emission reductions and any leakage effects, generated by the project activity

Metrogas has a Large Customers Division that offers solutions and develops businesses for industrial customers. This team has had a successful performance upon converting 400 industries to natural gas in a four-year period. This division has 12 engineers specialized in natural gas industrial use together with an area of technical support to the commercial management with 5 engineers and 9 technicians.

The Large Customers Division is supported in its business development and specialized engineering by well-known Consultant Gamma Ingenieros that has more than 30 years of experience in this field. The team focused on the cogeneration project is made up of 3 engineers.

On the other hand, Watt's Alimentos S.A. has appointed three engineers for project development and who are ensuring the technical quality of the interconnection systems for the electric and thermal supply.

Following project implementation, the Large Customers Division appointed an engineer to be in charge of administering the project, and who is, in turn, supported by the whole implementation team and by Metrogas in general.

The equipment supplier performs maintenance work since they have installations and a highly experienced technical team in Chile. The maintenance schedule is divided in 5 main procedures performed after 1000’s, 3000’s, 4000’s, 16000’s and 52000’s hours work, respectively. Most of maintenance work will be performed on Sundays.

Initially, the operation of Watt’s project will be subcontracted or, alternatively, Metrogas could be in charge of it. Whatever the case may be, the supplier will train 5 or 6 operators (more than the 3 that are necessary, one in each shift) as well as two engineers who will be in charge of supervision.

For the time being, the cogeneration operation will not be ISO 9001 certified, although Metrogas policy is to have all its processes ISO 9001 certified. For more details see Annex 6.

D.5 Name of person/entity determining the monitoring methodology:

Dr. Gautam Dutt and Ivana Cepon are from MGM International, S.R.L. (not project participants)

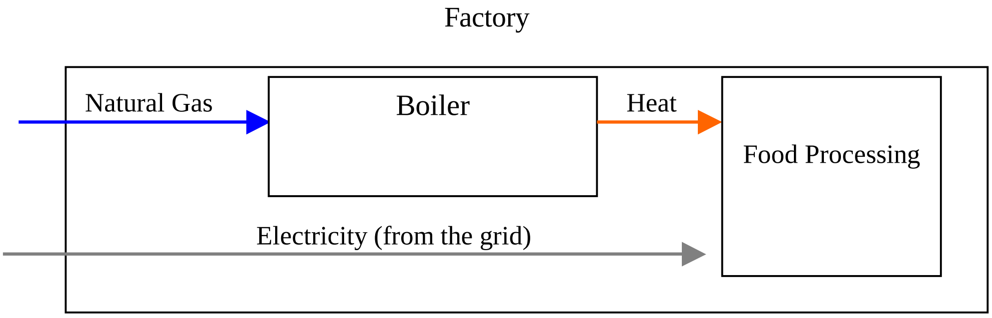
Junín 1655, 1 B
C1113AAQ Buenos Aires
Argentina
Tel. (54 11) 5219-1230/1/2
e-mail: icepon@mgminter.com; gdutt@mgminter.com

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

Figure E.1 compares the situation (a) before project implementation for heat and electricity supply to the industrial plant with the situation (b) after the cogeneration system has been installed. As in baseline section B.4, the project boundary is shown by the dashed line in Figure E.1. Note that the cogeneration system is sized to provide only a part of the factory's demand for electricity and the heat, so that the existing boilers continue to operate even after the cogeneration system has been installed, and the factory continues to purchase electricity from the grid.

a) <u>Current situation</u>



b) <u>After installation of cogeneration system</u>

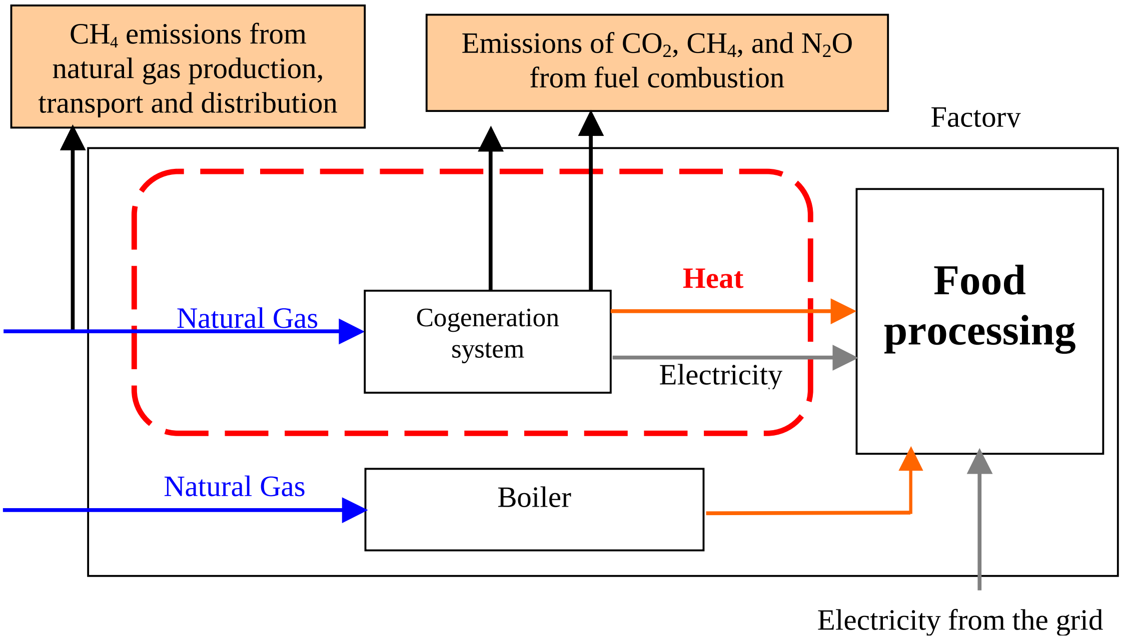


Figure E.1. Comparison of (a) current heat and electricity supply to the industrial plant and (b) after installation of cogeneration system. The dashed line depicts the project boundary.

Project GHG emissions within the project boundary correspond to natural gas consumed by the cogeneration system.

An *a priori* estimate of annual energy consumption is determined from the energy input rate of the cogeneration system (EIR_{cog}) and an estimate of annual operating hours (AOH) of the cogeneration system:

The estimated annual natural gas energy consumption by the cogeneration system, AEC_{NG} (GJ/year), is given by**:**

$$AEC_{NG}\,(GJ/year) = EIR_{cog} \cdot AOH \qquad \textbf{(Eq. E.1)}$$

where EIR_{cog} = Energy input rate to cogeneration system (GJ/h)

AOH = Annual operating hours (h/year)

The value obtained by applying the formulae above is AEC_{NG} *= 195,363 GJ/year.*

Once the natural gas energy consumption has been estimated *a priori*, each component of emissions may be estimated as described below:

a) Carbon dioxide (CO_2) emissions per year from natural gas combustion in the cogeneration system

Estimated CO_2 emissions from natural gas combustion in the cogeneration system, E_{cs} (tonne CO_2/year) are given by:

$$E_{CS}\,(tonne\ CO_2/year) = \frac{AEC_{NG} \cdot EF_{NG}}{10^3} \qquad \textbf{(Eq. E.2)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)

EF_{NG} = CO_2 emission factor of natural gas (kg CO_2/GJ, *lower* heating value basis)

Estimated E_{CS} *are = 10,960 tonne* CO_2*/year.*

b) Methane emissions (CH_4) from natural gas combustion

A certain amount of methane is generated in the combustion of natural gas. Emissions are estimated using formulae described below:

Estimated methane emissions from natural gas combustion, $E_{met\ comb}$ (tonne CH_4/year), are given by:

$$E_{met\ comb}\,(tonne\ CH_4/year) = \frac{AEC_{NG} \cdot MEF}{10^6} \qquad \textbf{(Eq. E.3)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)

MEF = methane emission factor for natural gas combustion (kg CH_4/TJ, *lower* heating value basis)

Convert to units of carbon dioxide equivalent emissions, $E_{equiv\ met\ comb}$ (tonne CO_2 equiv/year)

$$E_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv/year) = E_{met\ comb} \cdot GWP\,(CH_4) \qquad \textbf{(Eq. E.4)}$$

where GWP (CH_4) = global warming potential of methane = 21

The value obtained applying the formulae above is $E_{equiv\ met\ comb}$ *= 6 tonne* CO_2 *equiv / year.*

What is the value of *MEF*? Measured values of MEF for natural gas engines are not reported in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3, Reference Manual.* The closest values are for natural gas industrial boilers (Table 1-16, p. 1.54) and natural gas "commercial source" boilers (Table 1-19, p. 1.57). In order to be conservative, we take the upper of these two estimate: MEF = 1.4 kg CH_4/TJ., provide an estimate for ***MEF* of 1.4 kg CH_4 /TJ of natural gas energy input (lower heating value basis),** which is used in this PDD.

We may apply this value of *MEF* to Eq (E.3) and (E.4) to estimate methane emissions from combustion for natural gas consumption in the cogeneration system. We obtain CO_2-equivalent emissions of 6 tonnes per year. This is insignificant compared with the total project emissions, which add up to over 12,336 tonnes CO_2-equivalent per year. Thus the GHG emissions from methane in combustion is about 0.05% of total project emissions. *While we include methane emissions in combustion in this PDD, they may well be neglected*.

c) Nitrous oxide (N_2O) emissions from natural gas combustion

A certain amount of nitrous oxide is also generated in the combustion of most fuels. Emissions are estimated using formulae described below:

Estimated nitrous oxide emissions from combustion, *EN_2O comb* (tonne N_2O/year), are given by:

$$E_{N_2O\ comb}\ (tonne\ N_2O / year) = \frac{AEC_{NG} \cdot NEF}{10^6} \qquad \textbf{(Eq. E.5)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)

NEF = N_2O emission factor of natural gas (kg N_2O/TJ, *lower* heating value basis)

Convert to units of carbon dioxide equivalent emissions, $E_{equiv\ N2O\ comb}$ (tonne CO_2-equiv/year):

$$E_{equiv\ N_2O\,comb}\ (tonne\ CO_2 - equiv / year) = E_{N_2O\ comb}(tonne\ N_2O) \cdot GWP(N_2O) \qquad \textbf{(Eq. E.6)}$$

where $GWP\ (N_2O)$ = global warming potential of N_2O = 310

The estimated CO_2 equivalent emissions are $E_{equiv\ N2Ocomb}$ = 139 tonnes CO_2equiv /year

What is the value of *NEF*? There are little quantitative data on N_2O emissions from combustion, some of which are in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. However IPCC(1996) does not provide estimates for **gas engines.** The closest technology reported is natural gas boilers in the commercial source category in Table 1-19, p. 1.57. This value of ***NEF* of 2.3 kg /TJ energy input (lower heating value basis)**, is used in this PDD.

While the absolute value of the emissions factor for nitrous oxide in kg/TJ is similar to that for methane, the CO_2 equivalent emissions is much higher, because of the considerably higher GWP of N_2O. N_2O emissions for the project is estimated to be 139 tonnes CO_2-equivalent per year, compared to total project emissions of over 12,336 tonnes CO_2-equivalent per year. Thus, nitrous oxide emissions are relatively small, about 1.2% of total project emissions.

Total project emissions are given by the sum of the elements a) to c) analyzed above:

Estimated project emissions, *E(tonne CO$_2$-equiv / year)*, are given by:

$$E\,(tonne\,CO_2 - equiv / year) = E_{CS} + E_{equiv\ met\,comb} + E_{equiv\ \ N_2O\,comb} \qquad \textbf{(Eq. E.7)}$$

Total project emissions within the project boundary in the project scenario are estimated to be 12,336 tCO$_2$ equivalent per year.

E.2. Estimated leakage:

Project implementation implies greatly increased consumption of natural gas at the refinery. Methane is the principal component of natural gas and methane emissions at the gas wells, leakage from the natural gas pipeline supplying the refinery, as well as any leaks within the refinery may be considered leakage, also in the CDM sense, insofar as these emissions would not have occurred without project implementation.

Below we consider methane leakage from natural gas production, transport, and distribution.

Estimated fugitive methane emissions (natural gas production, pipeline and distribution leaks), E_{fug} **(tonne CH$_4$/year),** are given by:

$$E_{fug}\,(tonne\ CH_4 / year) = \frac{AEC_{NG} \cdot MLR}{10^6} \qquad \textbf{(Eq. E.7)}$$

where AEC_{NG} = annual natural gas energy consumption (GJ/year)
MLR = methane leakage rate (kg CH$_4$/GJ of natural gas consumption, LHV basis)

Convert to carbon dioxide equivalent emissions, $E_{equiv\ \ fug}$ **(tonne CO$_2$ equiv/year)**

$$E_{equiv\ \ fug}\,(tonne\ CO_2 - equiv / year) = E_{fug} \cdot GWP\,(CH_4) \qquad \textbf{(Eq. E.8)}$$

where $GWP\,(CH_4)$ = global warming potential of methane = 21

The value obtained by applying the formulae above is $E_{equiv\ \ fug}$ = 1,231 tonnes/year

What is the value of *MLR*?

Methane leakage from natural gas production. Natural gas that would be used in the project site is extracted in Argentina. However, country and well-specific data on methane emissions from natural gas production are not available for Argentina. We thus use region specific values indicated in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. Table 1-64 page 1.131 indicates values of 39,590 to 96,000 kg/PJ of gas *produced*. Since gas leaks are a small part of gas production, we may take the leakage to be approximately the same as kg per PJ of gas *consumption*, as well. We assume an average value of 70,000 kg/PJ of gas consumed at the project site.

This is the same as 0.07 kg/GJ of gas consumed. While this methane leakage is outside the project boundary, and indeed outside the country, we still need to account for it, since it takes place in another non-Annex 1 party.

Methane leakage from natural gas pipelines and distribution network. Since measured data on pipeline leakage are not available in Chile, we use standard estimates as suggested in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. Table 1-64, p. 1.131 indicates values of 116,000 to 340,000 kg of methane per PJ of natural gas consumed in the "Rest of the world" region where Chile would fall. We assume an average leakage value of 230,000 kg/PJ, i.e. 0.23 kg/GJ of gas consumed. In all cases, the energy content (GJ) is based on the *lower* heating value of the fuel.

Considering gas production, transport and distribution, we consider a methane emissions factor from leakage to be (0.07 + 0.23) or 0.30 kg/GJ gas consumption. Thus a value of **MLR = *0.30 kg/GJ of natural gas energy consumption (lower heating value basis)*** *is used in this PDD.*

The CO_2-equivalent of fugitive methane emissions associated with the project amount to 1,231 tonnes/year, which is about 10% of total project emissions of 12,336 tonnes/year. *Thus, these emissions are significant, and cannot be neglected.*

E.3. The sum of E.1 and E.2 representing the project activity emissions:

Total project activity emissions are given by the sum of the elements in E.1 and E.2 analysed above:

$$E_{total}\,(tonne\,CO_2 - equiv / year) = E + E_{equiv\ fug} \qquad \textbf{(Eq. E.9)}$$

where E refers to CO_2e emissions from natural gas combustion,

Total project activity emissions estimated are: 12,336 tonnes CO_2 equiv /year.

Note that each component of the emission is proportional to natural gas energy consumption. The estimates of project (and baseline) emissions, and reductions in this PDD are based in estimated operating hours, as given in (Eq. E.1). During project operation, these emissions and their reduction would be determined by actual monitored data of the cogeneration system operation.

E.4. Estimated anthropogenic emissions by sources of greenhouse gases of the baseline:

Baseline GHG emissions correspond to those emissions that are offset by heat and electricity output from the cogeneration system, supplied to the industrial plant.

The methodology and formulae for estimating each of these components of baseline emissions are described in D.2.1.4 and applied below.

The first four components of baseline emissions are proportional to natural gas consumption offset by the heat output of the cogeneration system.

Annual baseline natural gas energy consumption offset by heat output from the cogeneration system, *$ABEC_{NG}$* (GJ/year), is given by:

$$ABEC_{NG}\ (GJ/year) = \frac{CHOR \cdot AOH}{e_b} \qquad \textbf{(Eq. E.10)}$$

where $CHOR$ = cogeneration system heat output rate (GJ/h), and
AOH = Annual operating hours (h/year), and
e_b = boiler efficiency (LHV basis) = 0.829, using the highest efficiency measured (conservative assumption).

The value obtained by applying the formulae above is $ABEC_{NG}$ = 83,287 GJ/year

The value of ***CHOR*** is taken from the specifications of the cogeneration equipment.

The value of ***AOH*** is determined from an engineering analysis of the application of the package cogeneration system, and depends on the equipment characteristics as well as the characteristics of the demand for heat and electricity at the industrial plant.

The value of $\boldsymbol{e_b}$, the boiler efficiency at the industrial plant, was also determined in the engineering study. For the four boilers, the values were 0.546, 0.734, 0.812, and 0.829. See Annex 3. In order to be conservative, the highest value of e_b = 0.829 is used for this project.

a) Baseline carbon dioxide emissions from natural gas combustion.

Baseline carbon dioxide emissions from natural gas combustion, $\boldsymbol{BE_{th}}$ (tonne CO_2/year), are given by:

$$BE_{th}\ (tonne\ CO_2\ /\ year) = \frac{ABEC_{NG} \cdot EF_{NG}}{10^3} \qquad \textbf{(Eq. E.11)}$$

where $ABEC_{NG}$ = annual baseline energy consumption (GJ/year)
EF_{NG} = CO_2 emission factor of natural gas (kg CO_2/GJ, *lower* heating value basis)

The estimated baseline CO_2 equivalent emissions are BE_{th} = 4,672 tonnes CO_2equiv /year

The value of ***ABEC*** was determined above.
$\boldsymbol{EF_{NG}}$ depends on the fuel, and is best determined from national data sources, as indicated in the selected methodology.

b) Baseline methane emissions from natural gas combustion.

Baseline methane emissions from natural gas combustion, $BE_{met\ comb}$ (tonne CH_4/year), are given by:

$$BE_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG}\cdot MEF}{10^6} \qquad \textbf{(Eq. E.12)}$$

where $ABEC_{NG}$ = annual consumption of natural gas in the baseline (GJ/year)
MEF = methane emission factor for natural gas combustion (kg CH_4/TJ, *lower* heating value basis)

Convert to carbon dioxide equivalent emissions, $E_{equiv\ met\ comb}$ (tonne CO_2 equiv/year)

$$BE_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = BE_{met\ comb}\cdot GWP\,(CH_4) \qquad \textbf{(Eq. E.13)}$$

where $GWP\,(CH_4)$ = global warming potential of methane = 21

The value obtained by applying the formulae above is $E_{equiv\ met\ comb}$ = 2 tonnes CO_2 equiv /year.

<u>What is the value of *MEF*?</u> *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3, Reference Manual* provides estimates for natural gas industrial boilers (Table 1-16, p. 1.54). We use this value for ***MEF* of 1.4 kg CH_4 /TJ of natural gas energy input (lower heating value basis)** for the baseline.

We may apply this value of *MEF* to (Eq E.12) and (Eq. E.13) to estimate baseline methane emissions from natural gas combustion. We obtain CO_2-equivalent emissions of 2 tonnes per year. This is insignificant (about 0.01%) compared with the total baseline emissions, which add up to 14,729 tonnes CO_2-equivalent per year. *While we include methane emissions in combustion in this PDD, they may well be neglected.*

c) Baseline nitrous oxide emissions from natural gas combustion $BE_{N_2O\ comb}$ (tonne N_2O/year), are given by (Eq. E.14):

Baseline nitrous oxide emissions from natural gas combustion $BE_{N_2O\ comb}$ (tonne N_2O/year), are given by:

$$BE_{N_2O\ comb}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG}\cdot NEF}{10^6} \qquad \textbf{(Eq. E.14)}$$

where $ABEC_{NG}$ = annual consumption of natural gas in the baseline (GJ/year), and
NEF = nitrous oxide emission factor for natural gas combustion
(kg N_2O/TJ, *lower* heating value basis)

This is converted to units of carbon dioxide equivalent emissions, $BE_{equiv\ N_2O\ comb}$ **(tonne CO_2 equiv/year)** using (Eq. E.15).

$$BE_{equiv\ N_2O\ comb}\,(tonne\ \ CO_2 - equiv\,/\,year) = BE_{N_2O\ comb}\cdot GWP\,(N_2O) \qquad \textbf{(Eq. E.15)}$$

where *GWP* (N_2O) = global warming potential of nitrous oxide = 310

Nitrous oxide equivalent emissions estimated are: 59 tonnes CO_2 equiv /year.

What is the value of *NEF*? There are little quantitative data on N_2O emissions from combustion, some of which are in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Reference Manual*. IPCC (1996) reported an estimate for natural gas boilers in the commercial source category in Table 1-19, p. 1.57. This value of ***NEF*** **of 2.3 kg /TJ energy input (lower heating value basis)**, is used for the baseline.

Using (Eq. E.14) and (Eq. E.15), N_2O emissions for the baseline are estimated to be 59 tonnes CO_2-equivalent per year, compared to total baseline emissions of 14,729 tonnes CO_2-equivalent per year. Thus, nitrous oxide emissions are very small, about 0.4% of total baseline emissions.

d) **Baseline methane emissions** from natural gas production, pipeline and distribution leaks, $BE_{th\ fug}$ **(tonne CH_4/year),** are given by (Eq. E.16):

Baseline methane emissions from natural gas production, pipeline and distribution leaks, $BE_{th\ fug}$ (tonne CH_4/year), are given by:

$$BE_{th\ fug}\,(tonne\ CH_4\,/\,year) = \frac{ABEC_{NG}\cdot MLR}{10^3} \qquad \textbf{(Eq. E.16)}$$

where $ABEC_{NG\,=}$ is defined as before, and

MLR = methane leakage rate in natural gas production, transport and distribution leakage, including leaks at the industrial site (kg CH_4 /GJ natural gas energy consumption, lower heating value basis).

This is converted to units of carbon dioxide equivalent emissions, $BE_{th\ equiv\ fug}$ **(tonne CO_2 equiv/year)** using Eq. (3.9):

$$BE_{th\ equiv\ fug}\,(tonne\ CO_2 - equiv\,/\,year) = BE_{th\ fug}\cdot GWP(CH_4) \qquad \textbf{(Eq. E.17)}$$

where $GWP\ (CH_4)$ is defined as before.

Baseline methane emissions estimated are 525 tonnes CO_2 equiv /year.

What is the value of **MLR*?***, *since The gas supply infrastructure providing natural gas is the same in the baseline and in the project cases. Thus, the value of MLR in the baseline is the same as for the project case (see Sec. E.2):* **MLR = *0.30 kg/GJ of natural gas energy consumption (lower heating value basis)*** *is used for the baseline.*

The CO_2-equivalent emissions for methane release in the baseline is 525 tonnes/year compared to total baseline emissions of 14,729 tonnes CO_2-equivalent/year, i.e. about 3.5 % of the total. While this value is relatively small, it is not negligible, and should be considered in projects of this kind.

d) Baseline emissions of CO_2 from electricity supply.

Annual electricity generation from the cogeneration system, *CEO* **(MWh/year),** may be estimated by:

$$CEO\ (MWh\,/\,year) = CPO\cdot AOH \qquad \textbf{(Eq. E.18)}$$

where *CPO* = cogeneration system net power output capacity (MW_e) and
AOH = annual operating hours as defined with (Eq. E.10) (h/year)

Baseline carbon dioxide emissions that are offset by electricity supplied by the cogeneration system, BE_{elec} **(tonne CO_2/year),** are given by:

$$BE_{elec}\,(tonne\ \ CO_2\,/\,year) = \frac{CEO\cdot BEF_{elec}}{10^3} \qquad \textbf{(Eq. E.19)}$$

where BEF_{elec} = baseline CO_2 emissions factor for electricity from public supply (kg CO_2/MWh).

The value of ***CPO*** is taken from the specifications of the cogeneration equipment.

The value of ***AOH*** is determined as explained above (see text following (Eq. E.10), above).

To estimate $\boldsymbol{BEF_{elec}}$, the CO_2 emissions factor for electricity supply, we need to apply either "Consolidated Baseline Methodology for Zero-emissions Grid-Connected Electricity Generation from Renewable Sources" or "Simplified Methodology for Small-scale CDM Project activities" in case electricity displacing is less than or equal to 15 MW equivalent, as is being described by AM0014.

As this cogeneration system generates less than 15 MW, we apply the latter.

Appendix B of the simplified Modalities and Procedures for small-scale CDM project activities contains two options that can be applied in the selected project category:

"The baseline is the kWh produced by the renewable generating unit multiplied by an emission coefficient (measured in kgCO_2/kWh) calculated in a transparent and conservative manner as:

(a) The average of the "approximate operating margin" and the "build margin", where:

(i) The "approximate operating margin" is the weighted average emissions (in kgCO_2/kWh) of all generating sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation;

(ii) The "build margin" is the weighted average emissions (in kgCO_2/kWh) of recent capacity additions to the system, defined as the lower of most recent 20% of plants built or the 5 most recent plants;

OR,

(b) The weighted average emissions (in kgCO_2/kWh) of the current generation mix."

Option (a) is selected in this project.

Build margin estimation:
The most recent plants built adding up to 20 % of total generation, used to determine the build margin, are listed in Annex 3. The result is:

$\langle E \rangle_{\text{build margin}} = 0.371$ t-CO_2/MWh.

Operating margin estimation:
Data are shown in Annex 3. The result is:

$\langle E \rangle_{\text{operating margin}} = 0.591$ t-CO_2/MWh.

Baseline estimation:
From these results one has:

$$BEF_{\text{elec}} = \frac{\langle E \rangle_{buildmargin} + \langle E \rangle_{operatingmargin}}{2} = 0.481\,\text{t-CO}_2/\text{MWh}$$

Estimated baseline emissions of CO_2 from electricity supply, BE_{elec} (tonne CO_2/year), are 9,470 tonnes CO_2 equiv / year.

Total baseline emissions are given by the sum of the elements a) to d) analyzed above:

Total baseline emissions, BE_{total} (tonne CO_2-equiv/year), are given by (Eq. E.20):

$$BE_{total} = BE_{th} + BE_{equiv\ met\ comb} + BE_{equiv\ N_2O\ comb} + BE_{th\ equiv\ fug} + BE_{elec} \quad \textbf{(Eq. E.20)}$$

Total baseline emissions estimated are: 14,729 tonnes CO_2 equiv / year.

E.5. Difference between E.4 and E.3 representing the emission reductions of the project activity:

$$ER\ (tonne\ CO_2\text{-}equiv/year) = BE_{total} - E_{total} \qquad \textbf{(Eq. 11)}$$

Ex-ante emissions reductions are estimated to be 2,393 tonnes CO_2equivalent per year.

E.6. Table providing values obtained when applying formulae above:

Table E.1: Estimated baseline and project emissions, and reductions in the crediting period (tonnes CO_2 equiv/year)

Year	Baseline emissions	Project emissions	Leakage*	Emission reductions
2005	14,729	12,336	0	2,393.3
2006	14,729	12,336	0	2,393.3
2007	14,729	12,336	0	2,393.3
2008	14,729	12,336	0	2,393.3
2019	14,729	12,336	0	2,393.3
2010	14,729	12,336	0	2,393.3
2011	14,729	12,336	0	2,393.3
2012	14,729	12,336	0	2,393.3
2013	14,729	12,336	0	2,393.3
2014	14,729	12,336	0	2,393.3
Total	147,290	123,360	0	23,933

* Leakage emissions are from fugitive methane emissions in natural gas supply. Natural gas is used both in the baseline and in the project scenarios, and fugitive emissions are included in the total for baseline and project emissions. Note that fugitive emissions increase by 706 tonnes CO_2 equivalent per year following project implementation. For more details on calculations, see Annex 3.

SECTION F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

The “Fundamental Environmental Act” (Law Nr 19300, published in March 9, 1994) and the Rule of the Environmental Impact Assessment System (Supreme Decree Nr 30 of 1997) provide that investment projects in Chile shall be environmentally assessed prior its execution. The projects of the energy sector including cogeneration projects that must be submitted to the Environmental Impact Assessment System (SEIA) are the following (Art. 10 of the Fundamental Environmental Act):

- High voltage transmission lines and substations
- Electricity generating plants larger than 3 MW
- Oil pipelines, gas pipelines, mining ducts or analogue.

Installing a cogeneration system in the Watt’s factory will have little marginal impact on the environment.

Given that the total power output of the project is less than 3 MW, current regulation does not require an Environmental Impact Assessment, only that:

- A declaration be made to the Health and Environmental Service, once the project has been terminated.
- Measurements of particulate matter (PM) are made annually, and that they meet existing standards. The current standard requires PM to be less than 28 mg/Nm^3 when there is a situation of environmental emergency and 112 mg/Nm^3 in other periods. Both limits are easily met by the equipment which has emissions below 10 mg/Nm^3.

F.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

No significant negative impacts applicable.

SECTION G. Stakeholders’ comments

G.1. Brief description how comments by local stakeholders have been invited and compiled:

The process followed to collect stakeholder comments of the Metrogas S.A. Package Cogeneration Project went through a survey.

The following set of questions was sent to stakeholders, during the first week of July 2003:

1. Do you believe that the socio-economic situation of the Metropolitan Region will improve due to the implementation of the project?

2. How does the development of the project affect you (positively or negatively) or on your environment?
3. Would you recommend private companies or authorities to develop projects of this nature?
4. Do you think this will contribute to the Sustainable Development of Chile?
5. Any additional comments you would like to make.

G.2. Summary of the comments received:

The following table show a synthesis of the comments received (English translation and *original in Spanish*):

Question	Javier Antonio García Monge Entidad Comisión Nacional del Medio Ambiente Teléfono:56.2.240.5779, e-mail jgarcia@conama.cl
1	Yes, in any case, the improvement from a single project could be very small compared to the regional level. *(Sí, en todo caso, la mejora verificada en un proyecto puede ser muy pequeña comparada con el nivel de la región.)*
2	As projects of this type are developed, there is a positive impact on the quality of life of persons. *(En la medida que se desarrollen proyectos de este tipo hay un impacto positivo en la calidad de vida de las personas.)*
3	Yes. Besides the impact of this project for the specific company, the large benefits will be seen as this type of project is generalized. *(Sí. Más allá del impacto que este proyecto tenga en la empresa individual, los grandes beneficios se verán en la masificación de este tipo de proyectos.)*
4	Yes, to the extent that it means incorporating higher efficiency into energy use. *(Sí, en la medida que significa incorporar mayor eficiencia en el aprovechamiento de la energía.)*

G.3. Report on how due account was taken of any comments received:

Only one comment have been received, and it was very positive for project implementation.

Once the PDD is posted on the website of the Designated Operational Entity, additional comments may be received. Depending on those comments, account will be taken in a revised PDD, if necessary.

Annex 1

INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Metrogas S.A.

Organization:	Metrogas S.A.
Street address:	El Regidor 54, Las Condes
City:	Santiago
Country:	Chile
Telephone:	+56-2-337-8000
FAX:	+56-2-332-0344
URL:	www.metrogas.cl
Represented by:	
Title:	Gerente, Mercado Industrial
Salutation:	Mr.
Last Name:	Nelson
First Name:	Ian
Direct FAX:	+56-2-339-2701
Direct tel:	+56-2-339-2717
Personal E-Mail:	inelson@metrogas.cl

Electric Power Development Co.

Organization:	Electric Power Development Co., Ltd
Street address:	15-1, Ginza 6-Chome
City:	Tokyo
State/Region:	
Postfix/ZIP:	104-8165
Country:	Japan
Telephone:	+81.3.3546.2211
E-Mail:	webmaster@jpower.co.jp
URL	www.jpower.co.jp/english/
Represented by:	
Title:	Director, Climate Change
Salutation:	Mr.
Last Name:	Nonaka
First Name:	Yuzuru
Telephone:	+81.3.3546.2211
Department:	Corporate Planning and Administration Dept.
Direct FAX:	(81.3) 3546-9531
Direct tel:	(81.3) 3546-9375
Personal e-mail:	yuzuru_nonaka@jpower.co.jp

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No funds from public national or international sources are involved in any aspect of the proposed project.

Annex 3

BASELINE DATA

Baseline data for electricity

As indicated in AM0014, the emissions factor is determined using the approved Simplified Methodology for Small-scale CDM Project activities, requiring a determination of the Build Margin, the Operating Margin and a Combined Margin.

The data used for the calculations and results are shown below. The data correspond to the Central Interconnected System of the Republic of Chile (SIC), which corresponds to the location of the project activity and also includes the capital city of Santiago. The SIC provides electricity to 92.7% of the Chilean population.

Build Margin estimation:

Total power generation in 2004 was 36,344 GWh. The most recent power plants making up 20% of the power generation are shown in the Table below.

Power Plants Comprising the Build Margin

Plant Identification	Fuel Type	Year online	Generation (GWh/yr)	Emissions (ton CO2 / yr)
Valdivia	Black liquor/Biomass/Diesel	2,004	155.7	0
Lincanten	Biomass	2,004	21.4	0
Horcones	Natural Gas	2,004	12.1	5,750
Lag. Verde TG	Diesel	2,004	8.7	7,339
Ralco	Hydro	2,004	1,332.3	0
Nehuenco II	Natural Gas	2,003	1,996.3	776,620
Cholguán	Biomass	2,003	93.2	0
Nehuenco 9 B	Natural Gas/Diesel Petroleum	2,002	107.6	71,631
S. F. de Mostazal	Diesel Petroleum	2,002	9.4	10,040
Taltal 1 & 2	Natural Gas	2,000	988.8	642,645
Mampil	Hydro	2,000	174.2	0
Peuchén	Hydro	2,000	262.3	0
Petropower	Petroleum derivates	1,998	526.2	560,261
Nehuenco	Natural Gas/Diesel	1,998	1,847.9	719,730
Total			7,536.1	2,794,017

Note: Since Chacabuquito hydro is considered as CDM, it was excluded from the build margin scope.

From this information, one can determine that:

$\langle E \rangle_{\text{build margin}} = 0.371$ t-CO_2/MWh.

Operating Margin estimation:

The data used to determine the Operating Margin are shown in the Table below.

Power plants included in the determination of the operating margin

Plant Identification	Fuel Type	Generation (GWh/yr)	Emissions (ton CO2 / yr)
Ventanas 1	Coal	413.5	406,713
Ventanas 2	Coal	1,050.7	1,032,083
Renca	Coal/Diesel	6.6	4,257
Nueva Renca	Natural Gas/Diesel Petroleum	2,275.6	887,858
L.Verde	Coal	38.5	69,819
Lag. Verde TG	Diesel	8.7	7,339
Bocamina	Coal	300.1	297,648
Huasco Vapor	Coal	4.1	10,437
Huasco TG	Diesel Petroleum	29.1	34,155
Guacolda 1	Coal	1,240.8	1,212,048
Guacolda 2	Coal	1,238.3	1,207,383
D. de Almagro	Diesel Petroleum	6.2	7,276
S. F. de Mostazal	Diesel Petroleum	9.4	10,040
Nehuenco	Natural Gas/Diesel Petroleum	1,847.9	719,730
Nehuenco 9 B	Natural Gas/Diesel Petroleum	107.6	71,631
Nehuenco II	Natural Gas	1,996.3	776,620
San Isidro	Natural Gas	2,706.0	1,046,005
Taltal 1 & 2	Natural Gas	988.8	642,645
Valdivia	Black liquour/Biomass/Diesel	155.7	0
Celco	Black liquour/Biomass/Diesel	132.5	0
Arauco	Black liquour/Biomass/Diesel	156.0	0
Petropower	Petroleum derivates	526.2	560,261
Horcones	Natural Gas	12.1	5,750
Total		1,5250.7	9,013,162

From these data we determine that:

$\langle E \rangle_{\text{operating margin}} = 0.591$ t-CO_2/MWh.

Data sources for these calculations:

- Operational Statistics, ”Anuario 2004” (www.cdec-sic.cl)

Ex ante estimates of baseline and project emissions were determined using a spreadsheet model. The relevant tables are shown below.

Ex-ante Estimates of Baseline and Project Emissions

Project specific data of the situation *prior* to project implementation

Boiler	Natural gas consumption EPA 5 (1)		Diesel consum-ption EPA 5 (1)	Average of combustion efficiency (1)	Efficiency technical boilers (2)	Power technical net base HHV	Steam production isokinetic basis	Year of manu-facture
	kg/h	Nm^3/h	kg/h	%	%	Mcal/h	tonne/h	
Superior	527.4	732.5	------	81.2	79.2	6593	9237	1963
Cleaver Brooks	701.1	973.7	------	73.4	81.4	8764	12612	1996
Salcor	423.1	587.6	------	54.6	52.6	5289	4918	1996
G. Wagner	------	------	171	82.9	80.9	1864	2668	1978
						Total	**29435**	

(1) Source: Isokinetic sampling required by the Servicio de Salud Metropolitano del Ambiente (“Metropolitan Service of Environmental Health”).

(2) 2% is discounted due to losses in purges and radiation to the outside.

(3) Servicio Nacional de Salud (National Service of Health)

Project specific data from engineering analysis of potential cogeneration system

Cells marked with this color are project specific input. Others are calculated				
Cogeneration system				
Energy input rate (lower heating value basis)	24.73	MBtu/h	26.09 GJ/h	***EIR_{cog}***
Heat output rate (steam)	5.54	MBtu/h		
Heat output rate (hot water)	3.20	MBtu/h		
Heat output rate (total)	8.74	MBtu/h	9.22 GJ/h	***CHOR***
Electric power output	2.63	MW		***CPO***
Annual operating hours	7488	h		***AOH***
Expected electricity generation	19693	MWh/yr		
Industrial boiler efficiency (lower heating value basis)	0.829	***e_b***	The highest of the four values measured is used, in order to be conservative.	

Conversion factor:1 Btu =1055 J

Baseline emissions of GHG for heat supply to plant, offset by cogeneration system output

Basic parameters

	Technical characteristics	Value	Units
CHOR	Cogeneration system heat output rate	9.22	GJ/h
AOH	Annual operating hours	7488	hours
e_b	Industrial boiler efficiency	0.829	**LHV basis**
$ABEC_{NG}$	Boiler fuel use offset by cogen heat output	83287	GJ/yr

	Item	Value	Units	Data sources
CV_{NG}	Lower heating value	8407	kcal/m^3	= 35198 kJ/m^3. For natural gas in Chile. Value provided by Metrogas.
EF_{NG}	CO_2 emissions factor (combustion)	56.1	kg/GJ	Ref. 1, Table 1-1 pag 1.13. Natural gas (dry): 15.3 t C/TJ lower heating value basis. X 44/12 = 56.1 t CO2/TJ.
NEF	N_2O emissions factor (combustion)	2.3	kg/TJ	Ref. 1, Table I-19 page 1.57. Natural gas boiler.
GWP (N_2O)	Global Warming Potential (N_2O)	310		Ref. 2, for nitrous oxide this was 310.
MEF	CH_4 emissions factor (combustion)	1.4	kg/TJ	Ref. 1, Table I-16 page 1.54. Natural gas boiler.
	CH_4 emissions factor (natural gas production)	0.07	kg/GJ	Ref. 1, Table 1-64 page 1.131. 39590 to 96000 kg/PJ of gas produced.An average value of 70000 kg/PJ is considered here.
	CH_4 emissions factor (gas pipeline leakage)	0.23	kg/GJ	Ref. 1, Table 1-64 page 1.131. 116610 to 340000 kg/PJ of gas consumed. An average value of 230000 kg/PJ is considered here.
MLR	CH_4 emissions factor (natural gas production and pipeline leakage)	0.3	kg/GJ	Sum of above two emissions factors.
GWP (CH_4)	Global Warming Potential (CH_4)	21		Ref. 2, for methane this was 21.

References

1. IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Volume 3 (1996).
2. According to Article 5, section 3 of the Kyoto Protocol, GWP value is as agreed on at COP3.

Ex ante estimates of annual baseline emissions from natural gas combustion, including fugitive emissions in natural gas supply

Year	Year	Natural gas consumption ABEC (NG) GJ/ year	CO_2 emissions (combustion) BE_{th} t /year	N_2O emissions (combustion) $BE_{N2O\ comb}$ t /year	CH_4 emissions (combustion) $BE_{met\ comb}$ t /year	CH_4 emissions (natural gas production, and pipeline leakage) $BE_{th\ fug}$ t /year	Total CO_2 equiv emissions t /year	N_2O comb. (CO_2 equiv) $BE_{equiv\ N2O\ comb}$ t/year	CH_4 comb. (CO_2 equiv) $BE_{equiv\ met\ comb}$ t/year	CH_4 leakage (CO_2 equiv) $BE_{th\ equiv\ fug}$ t/year
1	2004	83287	4672	0,2	0,1	25	5259	59	2	525
2	2005	83287	4672	0,2	0,1	25	5259			
3	2006	83287	4672	0,2	0,1	25	5259			
4	2007	83287	4672	0,2	0,1	25	5259			
5	2008	83287	4672	0,2	0,1	25	5259			
6	2009	83287	4672	0,2	0,1	25	5259			
7	2010	83287	4672	0,2	0,1	25	5259			
8	2011	83287	4672	0,2	0,1	25	5259			
9	2012	83287	4672	0,2	0,1	25	5259			
10	2013	83287	4672	0,2	0,1	25	5259			

Ex ante baseline emissions of CO_2 from electricity supply to plant, that is offset by output from cogeneration system

Basic parameters

	Item	Value	Units
CPO	Cogeneration capacity	2.63	MW (elec) average
AOH	Annual operation hours	7488	hours
CEO	Cogeneration electric output	19693	

Ex ante annual baseline emissions from electricity consumption offset by cogeneration system

Year	Year	Electricity cogeneration CEO MWh/ year	CO_2 emissions factor for electricity from public supply BEF_{elec} kg CO_2 /MWh	CO_2 emissions t /year
1	2004	19693	481	9470
2	2005	19693	481	9470
3	2006	19693	481	9470
4	2007	19693	481	9470
5	2008	19693	481	9470
6	2009	19693	481	9470
7	2010	19693	481	9470
8	2011	19693	481	9470
9	2012	19693	481	9470
10	2013	19693	481	9470

Ex ante project emissions of GHG correspond to natural gas consumed by cogeneration system

Basic parameters

	Technical characteristics		Value	Units
EIR_{cog}	Energy input rate to cogeneration system (LHV basis)		26.09	GJ/h
AOH	Annual operating hours		7488	h/year
AEC_{NG}	Natural gas energy consumption, cogeneration system		195,363	GJ/year

	Item	Value	Units	Data sources
CV_{NG}	Lower heating value	8407	kcal/m^3	35198 kJ/m^3. For natural gas in Chile. Value provided by Metrogas.
EF_{NG}	CO_2 emissions factor (combustion)	56.1	kg/GJ	Ref. 1, Table 1-1 pag 1.13. Natural gas (dry): 15.3 t C/TJ lower heating value basis. X 44/12 = 56.1 t CO2/TJ.
NEF	N_2O emissions factor (combustion)	2.3	kg/TJ	Ref. 1, Table I-19 page 1.57. Natural gas boiler (closest config with value).
GWP (N_2O)	GWP nitrous oxide	310		Ref. 2, for nitrous oxide this was 310.
MEF	CH_4 emissions factor (combustion)	1.4	kg/TJ	Ref. 1, Table I-16 page 1.54. Natural gas boiler (closest config with value).
	CH_4 emissions factor (natural gas production)	0.07	kg/GJ	Ref. 1, Table 1-64 page 1.131. 39590 to 96000 kg/PJ of gas produced. An average value of 70000 kg/PJ is considered here.
	CH_4 emissions factor (gas pipeline leakage)	0.23	kg/GJ	Ref. 1, Table 1-64 page 1.131. 116610 to 340000 kg/PJ of gas consumed An average value of 230000 kg/PJ is considered here.
MLR	CH_4 emissions factor (natural gas production and pipeline leakage)	0.3	kg/GJ	Sum of above two emissions factors.
GWP (CH_4)	GWP methane	21		Ref. 2, for methane this was 21.

References

1. IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Volume 3 (1996).
2. According to Article 5, section 3 of the Kyoto Protocol, GWP value is as agreed on at COP3.

Ex ante estimates of annual project emissions from natural gas combustion, including fugitive emissions in natural gas supply

Year	Year	Natural gas consumption AEC (NG) GJ/ year	CO_2 emissions (combustion) E_{CS} t /year	N_2O emissions (combustion) $E_{N2O\ comb}$ t /year	CH_4 emissions (combustion) $E_{met\ comb}$ t /year	CH_4 emissions (natural gas production, and pipeline leakage) E_{fug}, t /year	Total CO_2 equiv emissions E_{total} t /year	N_2O comb. (CO_2 equiv) $E_{equiv\ N2O\ comb}$ t/year	CH_4 comb. (CO_2 equiv) $E_{equiv\ met\ comb}$ t/year	CH_4 leakage (CO_2 equiv) $E_{equiv\ fug}$ t/year
1	2004	195363	10960	0,4	0,3	59	12336	139	6	1231
2	2005	195363	10960	0,4	0,3	59	12336			
3	2006	195363	10960	0,4	0,3	59	12336			
4	2007	195363	10960	0,4	0,3	59	12336			
5	2008	195363	10960	0,4	0,3	59	12336			
6	2009	195363	10960	0,4	0,3	59	12336			
7	2010	195363	10960	0,4	0,3	59	12336			
8	2011	195363	10960	0,4	0,3	59	12336			
9	2012	195363	10960	0,4	0,3	59	12336			
10	2013	195363	10960	0,4	0,3	59	12336			

Ex ante estimates of annual baseline and project emissions and emissions reductions

		Baseline emissions, t CO_2 equiv/year			Project emissions t CO_2 equiv /year	Emissions reductions t CO_2 equiv /year
Year	**Year**	**Natural gas**	**Electricity**	**Total (BE_{total})**	**Total (E_{total})**	**ER**
1	2004	5259	9470	14729	12336	2393
2	2005	5259	9470	14729	12336	2393
3	2006	5259	9470	14729	12336	2393
4	2007	5259	9470	14729	12336	2393
5	2008	5259	9470	14729	12336	2393
6	2009	5259	9470	14729	12336	2393
7	2010	5259	9470	14729	12336	2393
8	2011	5259	9470	14729	12336	2393
9	2012	5259	9470	14729	12336	2393
10	2013	5259	9470	14729	12336	2393
Total				**147290**	**123357**	**23933**

Annex 4

MONITORING PLAN

The Monitoring and Verification Plan is based on recording natural gas used by the cogeneration plant, and electricity and heat supplied by cogeneration plant to the factory. Data will be collected on a monthly basis for the duration of the project lifetime and crediting period (10 years).

GHG emissions following project implementation are determined from the three parameters monitored, as described above. Project emissions basically comprise CO_2 emissions from natural gas combustion in the cogeneration plant. There is also some methane and nitrous oxide emissions from natural gas combustion. These are very small in magnitude and are estimated from standard emissions factors given by IPCC data sources. Associated with the natural gas consumed by the cogeneration plant are methane emissions from natural gas production and in leakage from the transport and distribution of natural gas. These GHG emissions are estimated from natural gas consumption data using standard estimates of emissions factors.

The emissions avoided in the power grid because of power generation of the cogeneration system are defined in terms of the emissions factors for the grid. The emissions factor would be determined annually from public data sources, as shown in Annex 3. No project specific monitoring is required to determine the emissions factor.

The monitoring plan describes the procedures for data collection, and auditing required for the project, in order to determine and verify emissions reductions achieved by the project. This project will require only straightforward collection of data, described below.

Considering the project boundary, the following data need to be monitored in order to estimate project and baseline emissions, and emissions reductions.

- Natural gas used by the cogeneration plant, m^3.
- Net electricity supplied by cogeneration plant to factory, MWh.
- Net heat supplied by cogeneration plant to factory, GJ.

The first three parameters should be monitored continuously and recorded monthly.

For efficiency of boiler(s) providing heat to the factory, we propose annual measurements of boiler efficiency, and using the highest measured value in order to determine fuel savings and emissions reductions from heat supplied by cogeneration system. Using the highest measured efficiency leads to a conservative estimate of emissions.

Besides the monitored data, we need to estimate methane emissions from natural gas production and gas pipeline leakage (internal and external to project site) corresponding to natural gas consumption, using standard emissions factors.

For the specific project considered in this PDD, a spreadsheet model has been designed.

The spreadsheet model takes monitored data as input, and automatically calculates both project and baseline emissions, for each year following project implementation, in a dynamic manner. As we have mentioned, baseline emissions are emissions avoided at the industrial plant because of heat and electricity supplied by the cogeneration system. Thus, during project implementation, baseline emissions are best determined in a dynamic manner, from monitored data on heat and electricity output from the cogeneration system.

The spreadsheet model is an electronic GHG monitoring and calculation workbook for package cogeneration projects. The electronic workbook serves as the data management and analysis system for the project managers and operators, and can be used throughout the lifetime of the project.

The monitoring spreadsheet is structurally very similar to that used in order to determine ex-ante baseline emissions and estimate project emissions. Tables from the baseline spreadsheet have been presented in Annex 3 of this PDD. The assumptions defining emissions factors are the same in each case, and are unchanged throughout the project. While emissions factors remain unchanged, baseline emissions depend on heat and electricity output from the cogeneration system, and are determined in a dynamic manner from data entered into the monitoring spreadsheet. The spreadsheet thus also determines emissions reductions as a result of project implementation.

The staff responsible for Project monitoring will complete the electronic worksheets on a monthly basis. Given that some of these data may be collected more frequently, data will be aggregated to allow monthly inputs into the spreadsheet. The spreadsheet automatically provides annual totals in terms of GHG reductions achieved through the implementation of the cogeneration system.

The monitoring spreadsheet determines the emissions associated with cogeneration system. The model contains a series of worksheets with different functions:

- Data entry sheets:
    - *Natural gas consumption,*
    - *Cogeneration electricity supply to plant, and*
    - *Cogeneration heat supply to plant*
- Calculation sheets:
    - *Project emissions*
    - *Electricity baseline*, and
    - *Heat baseline*
- Result sheet:
    - *Emissions reduction*

Annex 5

LETTER FROM CONAMA

Annex 6

GENERAL QUALITY CONTROL SYSTEM

The purpose of the quality control system is to obtain reliable data that will be used for the calculation of emission reductions. For this project, it is important to note that Metrogas S.A. is the owner of the cogeneration system and Watt's Alimentos S.A is the owner of the industrial plant and that uses the heat and electricity output from the cogeneration system. The final responsibility for monitoring, verification, and quality control will be with Metrogas S. A. From a CDM perspective, the relevant monitoring and verification would cover only the part of the quality management system linked to the CDM project and its corresponding MVP.

Since Metrogas S.A. has already implemented a quality control system, they will apply it in order to ensure correct measurement and data recording for the project.

A Procedure for measuring natural gas consumption

Metrogas has a procedure for measuring natural gas consumption. The general procedure includes the following items:

1. EQUIPMENT.

Natural gas consumption will be measured at an appropriate measuring station. This station shall have gas flow meters, and each shall have an individual calibration certificate issued by the factory.

The volume measured under the operating conditions of pressure and temperature will be converted to standard conditions, on a continuous basis by means of a digital corrector.

The elements to be used will comply with national standards and those agreed to by Metrogas S.A. with its cogeneration customer. The measurement of electricity must be realized according to national regulations in force.

For the measurement of thermal energy (steam and hot water), flow measurement devices, such as Vortex type, should be used. They include measurement of pressure and temperature. The meters should comply with EN 45001, 45002 and 45003 standards, or equivalent.

2. VERIFICATION AND CALIBRATION OF METERS AND CORRECTORS.

The equipment will be calibrated in accordance with the procedures established by the quality management system of Metrogas S. A.

In general, the calibration procedures will comprise the following steps:

A) Verification of Differential Pressure.

This will be done annually in accordance with the procedures defined by the manufacturers and approved by Metrogas S. A. as "Procedures for the Verification of Differential Pressure in Meters (indicate type of meter)".

B) Calibration of Correctors.

It will be done annually in accordance with the “Procedures for the Calibration of Correctors".

C) Calibration of Meters (indicate type of meter).

This will be done based on a "Procedure for the Calibration of Meters (indicate type of meter)” specified by Metrogas S. A. A Test Procedure provided by the meter manufacturer may be used, and will include a certified reference meter.

Such a procedure will be performed at least once every 5 years.

3. GAS CONSUMPTION READING AND BILLING.

A special “Unit for Reading and Recording Consumption" will be established. This Unit will employ qualified staff that will be in charge of reading and recording natural gas consumption.

The reading will be done in accordance with an established procedure, taking due note in a standard form the reading of the cumulated volume and the corrected one according to standard m^3, in addition to the name of Metrogas S. A., date, meter number, seal verification, pressure, temperature and instantaneous correction factor[3], cumulated reading of volume without corrections, name of the person who read the information, signature, etc. Information processing has to be made by sub-modules in energy billing. Independent review of collection should be made by an Administration Unit. Additionally, an engineer in charge of contract administration shall supervise all these procedures.

4. ELECTRICITY AND HEAT DELIVERY

The project manager shall define a clear procedure for electricity, steam, and heat as hot water measurement delivered by the Project. Measurements will be made on a monthly basis on the same day as natural gas consumption measurement. The procedure must follow good measurement practices of the local industry; the employees using these meters will receive prior training.

5. INTERNAL AUDIT

The person in charge of the project will conduct annual internal audits, checking the above mentioned procedures, in order to ensure their compliance. Thus, Metrogas S. A. an internal auditing procedure, which will in turn be evaluated by the DOE.

---

[3] **Note:** The standard m^3 measured will be transformed into equivalent m^3 with an associated, standard higher heating value (HHV). The first step is to calculate the energy content of the natural gas delivered, determined by multiplying the volume actually delivered by the average HHV of the gas delivered. The equivalent standard m^3 is then computed by dividing the energy content calculated above by the HHV of the standard natural gas. Thus, the energy delivered to a customer at a higher heating value can be calculated multiplying the equivalent standard m^3 by the standard HHV. The HHV of natural gas is normally measured by the gas company on a continual basis. Such values have to be revised and audited by Metrogas S. A. It should be noted that the heating value of natural gas is almost constant and presents small variations during each month.