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

CONTENTS

Annexes

The following Annexes would be added after methodologies have been approved, and prior to validation.

SECTION A. General description of project activity

A.1 Title of the project activity:

>> Shell Fuel Switching and Cogeneration Project

A.2. Description of the project activity:

>> The project activity primarily aims at reducing GHG emissions through fuel switching and improvements in cogeneration at an industrial facility, a refinery located in Buenos Aires, Argentina.

Prior to project implementation, electricity and steam were generated at the industrial site using a number of steam turbines and boilers. This equipment operated using a combination of asphalt, fuel oil and "fuel gas" which is a mixture of refinery gas and natural gas. With this configuration, the refinery meets all its requirements for heat and most of its electricity needs. Electricity is purchased from the network to meet the remaining demand.

The project consists of investment to replace some of the steam turbines with a gas turbine. The gas turbine would operate entirely on natural gas. As a consequence of project implementation, there will be considerable reduction in the use of asphalt, fuel oil and refinery gas, and an increase in natural gas consumption. Moreover, electricity generation capacity would be considerably increased so that excess electricity would be sold to the power grid. The industrial plant would thus shift from being a purchaser to being a seller of electricity.

The project sponsor is part of Shell, a global group of energy and petrochemicals companies, operating in over 145 countries. The specific project is at a petroleum refinery located in Buenos Aires, Argentina. Shell Compañía Argentina de Petróleo S.A. (Shell CAPSA) has operated its refinery in Argentina since 1931. It is the only refinery of the Shell Group in South America and produces LPG, gasoline, diesel, solvents, light diesel (called "gas oil" in Argentina), bunker fuel oil, basic lubricants, and asphalt.

Prior to project implementation, the plant used asphalt and other petroleum fuels (together with a small amount of natural gas purchased from the natural gas pipeline) to generate steam and electricity to meet refinery needs. Since electricity generated on site did not meet demand, additional electricity was purchased through the power grid.

The project involves fuel switching and the installation of a gas turbine cogeneration system. This latter would generate electricity to meet all of the refinery requirements, and sell the excess generation through the power grid.

The combination of fuel switching, improved efficiency of the cogeneration system, and offset electric power generation elsewhere in the power grid, implies reduced emissions of GHG, estimated to be 107,222 tonnes CO_2-equivalent per year.

The project also brings additional benefits mainly through fuel switching. Following project implementation, more natural gas and less liquid petroleum fuels will be used, which is expected to reduce airborne pollutants and improve air quality at and around the refinery.

Thus, the project brings environmental benefits, contributing to sustainable development objectives of Argentinean Government, in accordance with the General Environmental Law, the National Law Nº 25,675. (http://www.medioambiente.gov.ar/mlegal/marco/ley25675.htm)

The project is expected to obtain the written approval of the Argentina CDM Office for voluntary participation, confirming that the project supports sustainable development.

A.3. Project participants:

>>
1. Project Developer: Shell Compañía Argentina de Petróleo S.A.

2. Annex I country participant:

United Kingdom: Shell Trading International Limited

Japan: Showa Shell Sekiyu KK

See Contact Information in Annex 1 to this PDD.

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A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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A.4.1.1. Host Party(ies):

>>Argentina

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

>> Buenos Aires Province

A.4.1.3. City/Town/Community etc:

>> Dock Sud

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

>>
The project is located at Dock Sud industrial area, at the south of Buenos Aires Autonomous City, in Buenos Aires Province.

Buenos Aires City, the capital of the Argentinean Republic (Figure 1), is located in the centre of the country, bounded by La Plata River in the east. Its area is 200 km^2 and it is home to 2.8 million people. (According to the 2001 Census).

The city is surrounded, from the south to the north, by a big urban and suburban area called Gran Buenos Aires (Figure 2), with a population of 8.7 million and 3,680 km^2 of area. The industrial complex of Dock Sud is located in Gran Buenos Aires, in Avellaneda township. (Figures 3 and 4).

Figure1: Map of Argentina

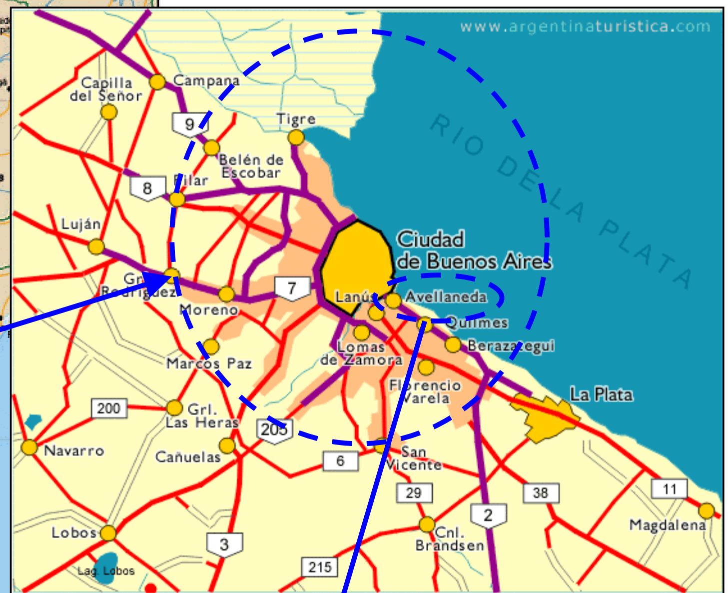

Figure2: Map of Gran Buenos Aires

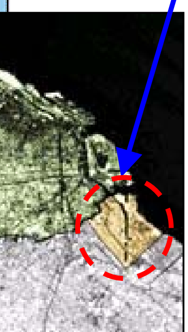

Figure3: Map showing Dock Sud Industrial Area location

Figure 4: Dock Sud Industrial Area

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

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The UNFCCC CDM web site appears not to provide a list of categories of project activities, from which one might choose that applicable for this proposed new methodology.

If one were to use the "Sectoral Scope" classification as applied to Designated Operational Entities, we would recommend the categories (1) Energy industries (renewable / non-renewable sources) and (5) Chemical industry.

A more specific category of project activity might be "industrial fuel switching, self-generation and cogeneration".

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

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Fuel switching involving the partial replacement of other fossil fuels by natural gas. Additionally, a gas turbine based cogeneration system would be introduced to offset fuel used in boilers and electricity purchased from the power grid.

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:

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The project involves the installation of a gas turbine generation system at a refinery in order to generate electricity. The waste heat from the gas turbine would also be used to supply part of the demand for steam at the power plant. As a result, there would be an improvement in plant efficiency in a thermodynamic sense, while generated electricity in excess of plant requirements would be supplied to the power grid, offsetting generation elsewhere. The installation of the natural-gas-fired gas turbine also involves fuel switching, whereby more carbon intensive petroleum fuels are replaced by natural gas, which has a much less carbon intensity. As a consequence of all aspects of project implementation, overall emissions of CO_2, and to a minor extent other GHGs, would be reduced, compared to the baseline situation.

Project additionality was analysed using the "Draft consolidated tools for the demonstration of additionality," published by the CDM Executive Board at their 15^{th} Meeting early in September 2004. Details are provided in Section B.3 of this PDD. We show that there are basically two categories of options: (a) the business as usual option involving the continued use of boilers and steam turbines and (b) the incorporation of a gas turbine based cogeneration together with the continued use of some of the boilers and some of the steam turbines. While there are any number of actual options in each case, depending on the capacity of the steam and gas turbines involved, two categories are qualitatively different: the first comprises the baseline, while the latter the project scenario.

Both the baseline and the project alternative options would meet applicable laws and regulations.

Additionality is established through an analysis of barriers, identifying three categories of barriers: (a) macroeconomic (the macroeconomic situation in Argentina inhibits all investments since the devaluation in early 2002); (b) wholesale power market rules (which have made investments in power generation not profitable since 1997); and (c) institutional barriers (which inhibit cogeneration in Argentina). Each are discussed in detail in Sec. B.3.

Our analysis indicates that the proposed project faces a number of barriers and its implementation would not have been considered at all if not for the possibility of emissions reductions credits. Thus, the proposed project is additional.

Estimation of the reduction in GHG emissions depends on two considerations: (a) the emissions factors and quantities of the fuels used at the refinery, in the baseline and project scenarios and (b) the emissions factor of the power grid connected to the refinery. The baseline methodology for making this determination is a new methodology being submitted with this PDD. This methodology is largely based on three methodologies previously approved by the Meth Panel and the CDM Executive Board: AM0008 (fuel switching to natural gas), AM0014 (package cogeneration at an industrial facility), and ACM0002 (grid-connected electricity generation from renewable sources). While the project does not involve renewable electricity generation, the electricity supplied by the cogeneration facility to the grid offsets emissions elsewhere in the power grid in the same manner as if this generation were renewable. This has already been recognized by the Meth Panel, who incorporated this component into AM0014, which also involves natural-gas based cogeneration.

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

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The *ex-ante* emissions reductions are estimated to be 107,222 tonne CO_2e/year for the crediting period of 7 years, which may be renewed. Note that actual emissions reductions will be based on monitored data and may differ from this estimate.

A.4.5. Public funding of the project activity:

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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:

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This project proposes a new methodology denominated:
"Fuel switching, and changes in self-generation and/or cogeneration at an industrial facility".

This new methodology incorporates ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" as well the Draft consolidated tools for the demonstration of additionality (Version 3 Sept. 2004, published as Annex 3 to EB 15 Report). The new methodology also builds on another approved methodology: AM0008 "Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility."

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

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The methodology was selected in order to be applicable to projects such as that proposed here. Moreover, it is based on several approved methodologies so it a combination of these methodologies rather than an entirely new one.

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

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The methodology is based on the case where baseline is defined in terms of "existing actual or historical emissions, as applicable", as defined in paragraph 48 (a) of CDM modalities and procedures.

The first step in applying the methodology is an evaluation of project additionality (sec. B.3, below).

Then an appropriate project boundary is established (sec. B.4).

Baseline and project emissions basically depend on (1) fuel consumption within the project boundary and the carbon content of the fuels used, (2) electricity purchases by and sales from the refinery to the power grid and (3) emissions factor of grid-connected power plants. Fuel consumption and electricity purchases and sales can be readily measured; the carbon content of fuels are known. The main difficulty is in determining the emissions factor for grid-connected power plants. We applied the ACM0002 to determine this and the difficulties stem from the data requirements of this methodology. The calculations are shown in Annex 3.

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:

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In May, July and early in September 2004, the CDM Methodology Panel and the CDM Executive Board have published a series of so-called "Draft consolidated tools for the demonstration of additionality." These documents in effect interpret the requirements specified in the Marrakesh Accords of the UNFCCC with respect to the operation of the Clean Development Mechanism.[1] While the most recent draft[2] is open for public comments (until Sept 20) and will be subsequently revised, this document provides the most recognized basis for the demonstration of project additionality.

These tools consist of Steps 0 through 5.

Step 0 is applicable to project activities that have started before registration. This is the case for the Shell Cogeneration project. The project started operation in mid 2003. Step 0 requires that evidence be publicly provided to show "that the incentive provided by the CDM was seriously considered in the decision to proceed with the project activity".

As a global energy company providing more than 3% of the world's oil and gas, Shell has been acutely aware of the climate change issues surrounding the burning of fossil fuels. For over two decades, Shell has been involved in activities to support biomass and other renewable energy sources, which generate little or no emissions of carbon dioxide. The current web page includes a section on sustainable development, which includes "helping the world gradually shift to a low-carbon energy system by providing more natural gas, and lowering the costs of alternatives like wind, solar power and fuels from plants".

All activities undertaken by Shell include environmental, social and health impact assessment. This assessment leads the identification of energy efficiency, cleaner energy sources, and other measures to reduce the environmental impact of Shell activities. Moreover, climate change considerations are a part of Shell decision-making. Shell keeps up with developments with respect to international treaties and government policies to mitigate climate change. Shell policy can be found at this website:

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[1] Decision 15/CP.7. Principles, nature and scope of the mechanisms pursuant to Articles 6, 12 and 17 of the Kyoto Protocol.

[2] Published as Annex 3 to the report of the 15th meeting of the CDM Executive Board.

http://www.shell.com/climate

Besides the publicly stated policies of the Shell Group, there are internal guidelines requiring that all project investments consider the economics of GHG emissions. Shell companies assume emitting man-made greenhouse gases (GHGs) will bear a cost, and that reducing GHGs will result in a revenue. This cost or revenue (depending on the jurisdiction) is factored into their project designs and investment decisions. A summary of Shell's Carbon pricing policy can be found at:

http://www.shell.com/home/Framework?siteId=royal-en&FC2=/royal-en/html/iwgen/environment_and_society/key_issues_and_topics/issues/climate_change/zzz_lhn.html&FC3=/royal-en/html/iwgen/environment_and_society/key_issues_and_topics/issues/climate_change/carbon_pricing_in_our_business.html

For the specific project in question, Shell Fuel Switching and Cogeneration Project, a so-called Group Budget Proposal was prepared, as is customary for evaluating project economics. This report provides a brief technical description of the project and summarises the conclusions of the financial analysis. The report includes estimates of reduced CO_2 emissions, among other environmental benefits. The sensitivity analysis of project economics considers possible variations in the price of crude petroleum, electricity price, maintenance costs, *as well as to "carbon credits" from CO_2 emission reductions*. This latter item is denominated "Sensitivity 6". The Group Budget Proposal was prepared in May 2001, long before project implementation, and confirms that potential revenues from GHG emissions reduction was a key component of this analysis. The Group Budget Proposal includes confidential information on project economics, which are not used to demonstrate project additionality. This document is included as an Annex to this PDD and will be made available only to the Designated Operational Entity (DOE) for Validation purposes. The DOE will not disclose it to any third parties, but is required to forward a copy to the UNFCCC Secretariat for record keeping, under the strict understanding that this Annex will not be available for public comments.

The argument presented above and the supporting documentation means that the Shell Fuel Switching and Cogeneration Project meets Step 0 of the Additionality tools.

Step 1 of the tools (Identification of alternatives to the project activity consistent with current laws and regulations) comprises a number of sub-steps:

Sub-step 1a. Define alternatives to project activity.

Prior to project installation, the boiler house at Shell CAPSA Refinery at Dock Sud, Buenos Aires, had boilers and steam turbines, providing all the steam requirements and some of the electricity requirements for refinery operations. Electricity was also purchased from the public supply to meet refinery requirements.

During project evaluation, the following options were considered:

1. The proposed project which comprises the purchase of a 25-MW gas turbine to operate on natural gas and a heat recovery steam generator to use waste heat from gas turbine exhaust to generate steam. Some of the steam turbines currently operating would not need to be operated, because all of the heat and power would be provided by the equipment acquired. Indeed, more electricity would be generated than required by the refinery, so excess electricity would be sold to the power grid. Since the gas turbine operates on natural gas, the refinery would purchase this fuel from the

gas pipeline, and stop using a combination of petroleum fuels. The thermodynamic efficiency of the heat and electricity supply would be improved and carbon dioxide emissions will fall.

2. Operating the boiler house with existing equipment, continuing to purchase electricity from the power grid, and burning petroleum fuels, as well as some natural gas purchased from the gas pipeline. Besides higher CO_2 emissions, this option would require maintenance costs in the future.

In principle, any number of combinations of gas and steam turbines and boilers can be imagined as alternative scenarios, where the resulting system would provide all the refinery steam requirements, and meeting a part or all of electricity demand.

A third alternative involving any combination of steam turbines and boilers would be similar to the baseline situation, insofar as efficiencies are likely to be similar, there would be no fuel savings or emissions reductions, so that investment requirements in replacing equipment would not be recovered. Thus this alternative may be discarded from the outset.

Gas turbines of different capacities in terms of electricity output could be combined with combinations of existing boilers and steam turbines. Many such combinations are likely to provide efficiency improvements as well reductions in GHG emissions. It is not practical to analyse all such possible combinations of equipment, but the different alternatives are not qualitatively different. Since investment analysis (Step 2) will not be invoked to establish additionality, these different alternatives involving gas turbines of different capacities are qualitatively the same as the project case, insofar as investments in equipment provide fuel savings and reduced GHG emissions.

Thus, we may consider the two cases listed above, as being the alternatives considered by Shell prior to investment decision, as well as being representative of all reasonable possibilities available.

Sub-step 1b. Enforcement with applicable laws and regulations

All alternatives considered by Shell, including the continued operation of the current equipment configuration, are intended to meet all applicable laws and regulations. The project activity is no way implied as required to meet any regulations. Thus, additionality is not lost because of this sub-step.

The consolidated tools then offer two options: Step 2 (Investment Analysis) or Step 3 (Barrier Analysis), with a third option of applying both Steps.

We choose not to apply Step 2 Investment Analysis for a number of reasons. We believe that investment analysis may be applied (in a trivial way) for projects where the only economic benefit of project activity is through CERs, e.g. nitrous oxide, PFC, HFC emissions reduction, and methane flaring (but not use as energy). Where a project has other revenues besides CERs, current and foreseeable CER prices are such that, save some rare exceptions, the difference in cost effectiveness with and without CER revenues is small so that projects are typically either not cost effective or cost effective, either way, i.e. CER revenues do not affect cost effectiveness in a significant manner. Even for those cases where CER revenues appear to be critical to project cost effectiveness, the results are highly sensitive to key assumptions, such as future energy prices, interest rates, CER price, etc. Moreover, this analysis assumes that financial considerations are the only ones relevant to decision making. For instance, security of fuel supply, technological dependence, equipment reliability, etc., are relevant. All these issues, as well as public image, affect decision making. In this case, we have the added situation that using Investment Analysis as an argument of additionality, would require full disclosure of proprietary know how involving project

economics, which may hurt one project proponent and benefit competitors. For these reasons, we do not choose to use Step 2 in order to demonstrate additionality.

Step 3 is Barrier Analysis.

We apply this Step for this project. We are required to show that barriers that:

(a) Prevent a wide spread implementation of this activity and thus preventing the baseline scenarios from occurring; and
(b) Do not prevent a wide spread implementation of at least one of the alternatives.

Step 3 also comprises two Sub-steps to analyse these two questions. However, in this case, we have shown above that there are only two basic alternatives, the project and the baseline. Thus, it is a question only of Sub-Step (a) comparing project and baseline, since there are no other alternatives to consider.

Sub-step 3a. Identify barriers that would prevent a wide spread implementation of the proposed project activity

We are required to establish that there are barriers that would prevent the proposed project activity from being carried out if the project were not registered as a CDM activity. Such barriers may include, among others:

1) Investment barriers
2) Technological barriers
3) Barriers due to prevailing practice
4) Other barriers

We will show the project activity faces an *investment barrier* that all power generation faces in Argentina, as well as an *institutional barrier* which inhibits cogeneration in Argentina. Each are discussed below.

Investment barriers

The "Consolidated Tools" mentions investment barriers "other than the economic/financial barriers in Step (2), e.g.:

- Real and/or perceived risks associated with the unfamiliar technology or process are too high to attract investment
- Funding is not available for innovative projects

In considering investment barriers, we have to place ourselves in the macroeconomic context of Argentina. Following several years of recession, the "country risk" reached values above 2000 by year-end 2001. A country risk of 2000 means that the interest rates would be 20 percentage points above international reference values such as LIBOR. At year-end, Argentina declared a "default" on its debt repayment commitments. Shortly afterwards, early in January 2002 (after there had been four changes of president in little over a week), the new government announced an end to the 10-year long era when the Argentine Peso was traded at par with the US$. The speculation that followed led the exchange rate to reach over 4 Pesos to the US$. Since then, the value has come down, and is currently around 3 Pesos to the US$. During all this period, the "country risk" reached astronomical values.

The reduction in money supply even before 2001 caused many provincial governments as well as the national governments to issue secondary currency, nominally called bonds, but which looked like and were denominated as currency notes, in order to make payments to government employees and suppliers.

These pseudo-currencies were widespread so that by the end of 2001, many stores accepted a wide range of these "currencies" even those belonging to other provinces. Before year-end 2001, the government sharply bank accounts were frozen and withdrawals from bank accounts were rationed, typically to 200 Pesos per week (equivalent to 200 US$ up to the end of 2001.) In early 2002, most bank deposits were frozen, dollar accounts converted to Pesos at a rate much lower than the market exchange rates, etc.

Long before this, no capital was available among domestic investors. Foreign investors had also largely disappeared in 2001 as the country risk reached and stayed at high values. The investment climate has remained unchanged until now.

If the investment climate in general deteriorated from 2001 on, it was even worse for electricity generation, and from much earlier.

Following deregulation in 1992, electricity generation is a "competitive" enterprise in Argentina. Generators supply electricity to national grids, and are dispatched in order of variable costs until demand is met. All generators are then paid a price for electricity that depends on the variable cost (basically fuel cost) of the marginal generation. For several years, this provided incentives to generation companies to incorporate new efficient generation equipment, with low operating cost. Thus, total installed capacity increased while wholesale electricity prices fell. In the process, many of the inefficient thermal power plants were eliminated from the system. By 1997, this process was so advanced that the price was set by marginal generators that were so efficient that their variable cost was relatively low. Those who had installed new efficient equipment saw returns on their investment drop to such values (about 20 Pesos per MWh, see Figure B.3.1 below) that they lost all incentive for further investment in power plants. Not that at from 1992 to year end 2001, 1 Peso = 1 US Dollar, so that the wholesale electricity price fluctuated between 20 and 30 US$ per MWh until the devaluation in early 2002. Shell realized a financial analysis of the proposed project in 2001, assuming an electricity sale price of 20 US$ per MWh and an electricity purchase price of 30 US$/MWh[3].

Since the devaluation in early 2002, and with about 4 Pesos to the US$, the wholesale price of 30 Pesos per MWh was equivalent to about US$ 7.5 per MWh, perhaps the lowest prices in the world (prices in Brazil and Chile are between US$ 35 and 45 per MWh[4]) , and far lower than a reasonable price to permit cost recovery of sunk investments, let alone add capacity. Even now, with 3 Pesos to the US$ and a wholesale price spike of between 35 and 40 Pesos per MWh, this is still only about 12 or 13 US$ per MWh.

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[3] Shell, 2001. Group Budget Proposal for Shell CAPSA cogeneration project.

[4] AGEERA (Asociación de Generadores de Energía Eléctrica de la República Argentina), 2002. *AGEERA Novedades*, No. 6, May.

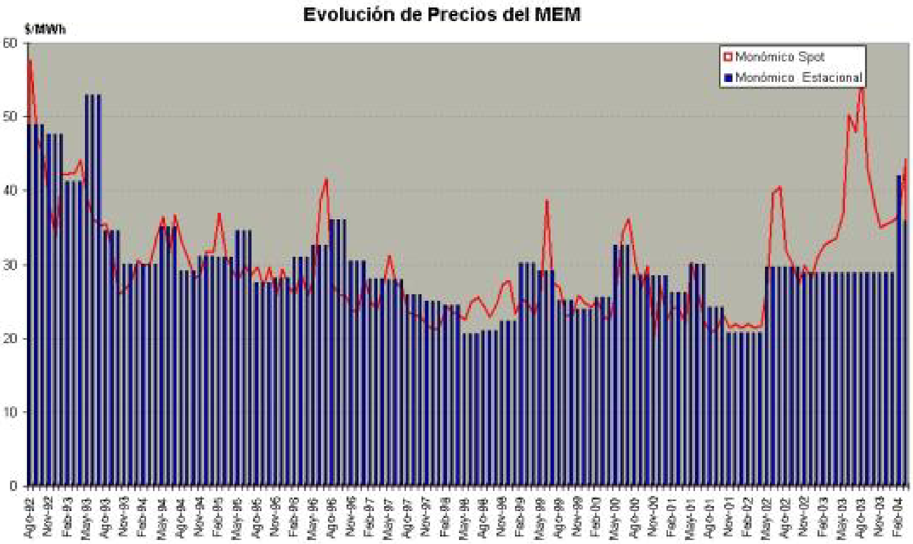

Figure B.3.1. Evolution in wholesale electricity prices in Argentina, 1992-2004. Values shown are in Pesos, which remained at a par with the US$ up to year end 2001. In January 2002, the currency was devalued and exchange rate has varied between 2.7 Pesos and 4 Pesos per US$ with a typical exchange rate being 3 pesos per US$.

In summary, investing in electricity generation in Argentina has been an unprofitable venture since 1997, even for conventional generation technologies. The proposed project would turn the Shell CAPSA refinery into a net exporter or electricity which will be sold to the wholesale market at the prevailing, low prices. Thus the project presents a significant investment barrier

Institutional barrier

Other rules of operation of the power market in Argentina also inhibit the installation of cogeneration. While, in Argentina cogenerators have open 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 six months at a time. Thus, it 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. Thus, the open market power system of Argentina, and other countries that underwent power sector reforms in the 1990s, favoured competition among power generators, but also implied 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 Argentina.

Following the application of either Step 2 or Step 3 (or both), the Consolidated Tools for Additionality require Steps 4 and 5, which are considered below.

Step 4 is Common Practice Analysis

Step 4 states:

> *"The above generic additionality tests shall be complemented with an analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and region. This test is a credibility check to complement the investment analysis (Step 2) or barrier analysis (Step 3)."*

This step ensures that the stated barriers indeed have prevented similar projects from taking place. It is a credibility test on the validity of the barriers to project implementation. Step 4 comprises two Sub-Steps, which are discussed below.

Sub-step 4a. Analyse other activities similar to the proposed project:

1. Provide an analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity. Projects are considered similar if they are in the same country and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Provide quantitative information where relevant.

Ever since deregulation of the power sector in Argentina in 1992, cogeneration has always faced significant barriers. As a result there are few such projects in the country. Three cogeneration projects are listed in the data base of the wholesale electricity management company (CAMMESA, Compañía Administradora del Mercado Mayorista Eléctrico S.A.). They are:

1. CMSENSEC CMS Ensenada.
2. SIDERCAC Siderca and
3. CTMENZAC C. T. Mendoza.

Here CMSENSEC and CTMENZAC are both cogeneration systems installed in refineries of Argentina's largest petroleum company, YPF. In both cases, the cogeneration system is owned by another company that provides heat and electricity to the refinery. Thus they operate in a "package cogeneration" mode, where the industry where the equipment is cited is not the owner of the cogeneration system. CMSENSEC is the oldest industrial cogeneration facility in Argentina and has been operating since Aug. 1997 (CAMMESA Annual Report, 1997). The other cogeneration facility CTMENZAC has been operating since the 1980s, prior to power sector deregulation and privatization.

SIDERCAC is a cogeneration plant owned by a steel mill. The parent company of the steel mill is the holding company TECHINT that owns steel mills at two cities in Buenos Aires province: San Nicolás and Campana. This cogeneration plant is physically located at the San Nicolás facility and "sells" electricity to the Campana steel mill, using the public transmission line. The cogeneration plant has been operating since Sept. 1997 (CAMMESA Annual Report, 1997).

Thus we note that the barriers operating against cogeneration since deregulation, and prior to the devaluation in early 2002, permitted only three cogeneration plants to be constructed during the period 1992-2001. After 2001, the *investment climate* in Argentina changed completely, as did key aspects of the *regulatory framework* for the power sector, and no further cogeneration projects were realized, except for the project in question.

Sub-step 4b: "Discuss any similar options that are occurring" does not apply since no similar activities are widely observed nor commonly carried out.

The final step for demonstrating additionality is Step 5. Impact of CDM Registration

The consolidated tools states:

"Explain how the approval and registration of the project as a CDM activity, and the attendant benefits and incentives derived from the project activity, will alleviate the economic and financial hurdles (Step 2) or other identified barriers (Step 3) and thus enable the project to be undertaken."

Earlier in the section, we have already commented that Shell, as one of the largest energy companies, is acutely aware of climate change, and includes GHG emissions in all its investment decisions. Approval and registration of this project as a CDM activity would therefore be of great significance to Shell, showing that its activities are helping to mitigate climate change. CDM registration will provide independent confirmation of Shell's corporate responsibilities in the climate change area.

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

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The project boundary is the boiler room / power station (BRPS) located within the refinery. Petroleum fuels from the refinery itself plus natural gas from the gas pipeline outside the refinery supply fuel to the boiler room /power station. Electricity and steam are generated in the BRPS. Electricity is supplied from the BRPS to the rest of the refinery. When generated electricity is insufficient to meet demand (such as in the baseline case), additional electricity is purchased from an electricity distribution company through the power grid. When BRPS electricity generation exceeds refinery demand (as is expected in the project scenario), excess electricity would be sold to the wholesale power market through the power grid.

This choice of project boundary makes sense for various reasons:

- The project involves changes in the equipment within the BRPS, and not in the rest of the factory.
- The boiler room / power station (BRPS) is denominated "Usina" in the refinery and is a separate operational unit. This unit maintains strict records of fuel input to the BRPS, steam and electricity output from the BRPS to the refinery, as well as any electricity bought or sold through the public grid.

See baseline methodology for choices of project boundary.

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:

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

Date of completion of the baseline study: October 12, 2004.

Baseline study prepared by
Dr. Gautam Dutt and Ing. Nuria Zanzottera, MGM International, Ltda. (not a project participant).
Tel: +54-11-5219-1230
e-mail: gdutt@mgminter.com; nzanzottera@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:

>>September 2003.

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

>>25 years

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

C.2.1. Renewable crediting period

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

>>January 1, 2004.

C.2.1.2. Length of the first crediting period:

>>7 years.

C.2.2. Fixed crediting period:

NOT SELECTED.

C.2.2.1. Starting date:

>>

C.2.2.2. Length:

>>

SECTION D. Application of a monitoring methodology and plan

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

>>
Fuel switching, and changes in self-generation and/or cogeneration at an industrial facility.

This new methodology incorporates ACM0002 “Consolidated monitoring methodology for grid-connected electricity generation from renewable sources” and builds on another approved methodology: AM0008 “Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility.”

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

>>
The methodology was selected in order to be applicable to projects such as that proposed here. Moreover, it is based on several approved methodologies so it is partly a combination of these methodologies rather than an entirely new one.

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
P.1 $AFC_{a,i}$	*Annual fuel consumption for asphalt (a) in boiler i*	*Refinery*	*tonne SRF*	*m*	*month*	*100%*	*Paper (field) and electronic*	*SRF: standard refinery fuel, an equivalent energy unit. Subscript 'a' refers to fuel asphalt. 'i' refers to boiler or other equipment using fuel.*
P.2. $AFC_{fg,i}$	*AFC for fuel gas in boiler i*	*Refinery*	*tonne SRF*	*m*	*month*	*100%*	*Paper (field) and electronic*	*Subscript 'fg' refers to fuel gas, which is mostly refinery gas blended with natural gas.*
P.3. $AFC_{fo,i}$	*AFC for fuel oil in boiler i*	*Refinery*	*tonne SRF*	*m*	*month*	*100%*	*Paper (field) and electronic*	*Subscript 'fo' refers to fuel oil.*
P.4. AFC_{ng}	*AFC for natural gas in heat recovery boiler*	*Refinery*	*tonne SRF*	*m*	*month*	*100%*	*Paper (field) and electronic*	*Subscript 'ng' refers to natural gas.*

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

>>

The project activity involves replacing some fossil fuels currently being used by natural gas for providing heat and electricity in the refinery. The project activity also involves increased electricity generation at the facility with increased export to the connected power grid. Both of these components would reduce GHG emissions compared to the baseline.

The project emissions E (expressed in tonnes of CO_2 equivalent per year, tCO_2e/yr) are given by:

$$E = \sum_i FC_i \cdot (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O))$$

where:

FC_i	consumption of fuel i used in the project scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel i (e.g. tCO_2e/GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel i (e.g. tCH_4/GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period
NEF_i	nitrous oxide emission factor per unit energy of fuel i (e.g. tN_2O/GJ) (combustion)
$GWP(N_2O)$	global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period

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
B.1. $SFC_{a,i}$	*specific fuel consumption asphalt in equip. i*	*Refinery*	*tonne SRF /100 t HPS*	*m*	*month*	*100%*	*Paper (field) and electronic*	*HPS: high pressure steam.*
B.2. $SFC_{fg,i}$	*SFC for fuel gas, equip i*	*Refinery*	*tonne SRF /100 t HPS*	*m*	*month*	*100%*	*Paper (field) and electronic*	
B.3. $SFC_{fo,i}$	*SFC for fuel oil, equip i*	*Refinery*	*tonne SRF /100 t HPS*	*m*	*month*	*100%*	*Paper (field) and electronic*	
B.4. SFC_{ng}	*SFC for natural gas in heat*	*Refinery*	*tonne SRF /100 t HPS*	*m*	*month*	*100%*	*Paper (field) and electronic*	

	recovery boiler							
B.5. NPES	*Net electricity sales to grid in project scenario*	*Refinery / power co.*	*MWh*	*m*	*month*	*100%*	*Paper (field) and electronic*	*Following project implementation, there will be a surplus generating capacity in the refinery so that there electricity purchases in the project scenario will be limited to brief intervals and small amounts.*
B.6. NBEP	*Net electricity purchases from grid in baseline scenario*	*Refinery / power co.*	*MWh*	*m*	*month*	*100%*	*Paper (field) and electronic*	*No electricity was sold to grid prior to project implementation. Thus NBEP = BEP.*
B.7. EF_{OM}	CO_2 *operating margin emission factor for grid*		*t* CO_2*/ MWh*	*c*	*year*	*100%*	*electronic*	*Determine Simple operating margin, as defined in ACM0002 and interpreted in Annex 3 of this PDD. Calculate updated value for each year.*
B.8. EF_{BM}	CO_2 *build margin emission factor for grid*		*t* CO_2*/ MWh*	*c*	*year*	*100%*	*electronic*	*Determine build margin, as defined in ACM0002 and interpreted in Annex 3 of this PDD. Calculate updated value for each year.*
B.9 $EF_{elec\ gen}$	CO_2 *combined margin emission factor for grid*		*t* CO_2*/ MWh*	*c*	*year*	*100%*	*electronic*	*Determined as average of* EF_{OM} *and* EF_{BM}*.. Update annually.*

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 emissions *BE* (expressed in tonne CO_2equivalent per year, tonne CO_2e/yr) are given by:

$$BE = \sum_i BFC_i (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O)) + (NBEP + NPES) \cdot EF_{elec\ gen}$$

where

BFC_i	consumption of fuel *i* used in the baseline scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel *i* (e.g. tCO_2/GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel *i* (e.g. $tCH_4/$ GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period
NEF_i	nitrous oxide emission factor per unit of energy of fuel *i* (e.g. $tN_2O/$ GJ) (combustion)
$GWP(N_2O)$	global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period
$NBEP$	net electricity purchased (electricity purchased less electricity sold) through the grid in the baseline (e.g. MWh)
$NPES$	net electricity sold (electricity sold less electricity purchased) through the grid in the project scenario (e.g. MWh)
$EF_{elec\ gen}$	baseline “combined margin” emission factor for grid electricity generation (e.g. kg CO_2e/MWh)

Baseline emissions correspond to the emissions from fuels burnt at the refinery in the baseline scenario. Electricity purchased through the power grid to meet a part or all of the demand at the refinery would cause emissions elsewhere in the power grid. Such emissions are included in the baseline emissions. Following project implementation, electricity is expected to be sold from the refinery through the power grid, so that emissions would be offset elsewhere in the grid. In the absence of such electricity supply in the baseline scenario, there would be additional emissions in electricity generation, which are also included in baseline emissions.

Note that we consider *net* electricity purchase from the grid in the baseline scenario and *net* electricity sold through the grid in the project scenario, as explained in the definitions of *NBEP* and *NPES*. This equation allows for one or other of these quantities to be negative. To avoid confusion these emissions are included in the baseline emissions equation only. In the proposed project, both terms are expected to be positive.

The emissions associated with electric power generation depend on the sum $NBEP + NPES$ and $EF_{elec\ gen}$, the emissions factor for electricity generation in the connected power grid.

The methodology proposed here is based on the approved consolidated monitoring methodology ACM0002 “Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources” for the purpose of determining $EF_{elec\ gen}$. ACM0002 offers some alternative

pathways for determining $EF_{elec\ gen}$. For this project, the data available permit the use of the Simple Operating Margin and the Build Margin based on the most recent power plants built accounting for 20% of the total generation. Details of the procedure, data and results are shown in Annex 3.

The *ex-ante* baseline emissions may be determined using values of annual fuel consumption AFC_i based on trends in consumption prior to project implementation, e.g. assuming a fixed growth rate in increase in fuel consumption. However, the boiler room /power plant where the project is to be implemented involves several fuels, several boilers and steam turbines, as well as a gas turbine in the project scenario. This complex thermodynamic environment makes it difficult to make an *ex-ante* estimation of project fuel consumption and emissions.

The alternative procedure suggested in the baseline methodology, involving a thermodynamic analysis of baseline and project configurations, supplemented by measured data on past fuel consumption trends and equipment efficiency, as well as nominal values of new equipment to be installed, is the basis for *ex-ante* estimates of baseline and project emissions.

If the past fuel consumption trends indicate that baseline emissions are basically constant, then the *ex-ante* baseline emissions could be based on the historic data. Alternatively, the methodology allows for *ex post* baseline emissions to be determined in a dynamical manner from project monitoring data using a surrogate variable to adjust for changes in fuel consumption as a function of industrial production. The surrogate variable may be heat or electricity demand supplied by the equipment in the project boundary.

This specific project uses a fixed baseline based on historic data.

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 USED

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.):

>>

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

Fugitive CH_4 emissions from fuel production and transport, and CO_2 emissions from fuel transportation are categorized as leakage. The fuels used in the project are produced within the refinery, with the exception of natural gas. Thus only methane emissions from natural gas production and gas pipelines are relevant here.

Since emissions associated with leakage are very small compared with project and baseline emissions, they are estimated from IPCC default values, without any requirement for monitoring.

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

>>

The leakage LE_y is expressed as

$$LE = (FC_i - BFC_i) \bullet FE_i(CH_4) \bullet GWP(CH_4) + \sum_j TF_j \bullet EF_j - \sum_k BTF_k \bullet EF_k$$

where $FE_i(CH_4)$ is the IPCC default methane emission factor of fuel i associated with fugitive emissions. In this case, only natural gas is relevant. Fugitive methane emissions are associated with natural gas production and pipeline leakage, and are included here.

The second line in the above formula refers to emissions from fuel transportation, which can be ignored for this project, since the fuels are produced on site.

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:

$ER = BE - E - LE$ expressed in tonnes of CO_2 equivalent (tCO_2e/yr).

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
LE are leakage emissions estimated as indicated in section D.2.3.2.

Note that an important component of determining emissions reductions depends on baseline emissions associated with electric power generation connected to the grid. These are described in Annex 3.

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.
Table D.2.1.1, P.1	*Low*	*Procedures include calibration of instruments used to measure fuel consumption*
P.2	*Low*	*Procedures include calibration of instruments used to measure fuel consumption*
P.3	*Low*	*Procedures include calibration of instruments used to measure fuel consumption*
P.4	*Low*	*Procedures include calibration of instruments used to measure fuel consumption*
Table D.2.1.3, B.1	*Low*	*Procedures include calibration of instruments used to measure heat output(as well as fuel consumption)*
B.2	*Low*	*Procedures include calibration of instruments used to measure heat output(as well as fuel consumption*
B.3	*Low*	*Procedures include calibration of instruments used to measure heat output(as well as fuel consumption*
B.4	*Low*	*Procedures include calibration of instruments used to measure heat output(as well as fuel consumption*
B.5	*Low*	*Procedures for calibration of electricity meters*
B.6	*Low*	*Procedures for calibration of electricity meters*
B.7	*Low*	*Determined from published data obtained from national load dispatch centre CAMMESA.*
B.8	*Low*	*Determined from published data obtained from national load dispatch centre CAMMESA*
B.9	*Low*	*Simple calculation.*

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

>>

Shell CAPSA already maintains excellent records of the data required for monitoring purposes. Thus no changes in operational and management structure will be required. The monitoring plan incorporates a procedure for utilising the monitored data and determining project emissions, estimating (dynamic) baseline emissions and emissions reductions. Record keeping will include calibration of measuring equipment, including flow and other meters for fuel consumption measurement, steam flow and quality measurements, as well as electricity output to the refinery and sold through the power grid.

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

>>

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

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

>>

Figure E1 shows the baseline situation for heat and electricity supply to the refinery, including the purchase of extra electricity from the grid, while Figure E2 shows the situation after project implementation, involving the installation of a gas turbine system and the sale of surplus electricity through the grid. The project boundary is shown by the dashed line in Figures E1 and E2. Note that the gas turbine installed together with some of the previously existing equipment can provide all of the refinery's demand for electricity and the heat with surplus of electricity to be sold through the grid. Note further that the heat recovery steam generator (HSRG) that uses exhaust heat from the gas turbine to produce steam includes a supplementary boiler for co-firing, using natural gas. While this is included in the figure here, it is not expected to be used.

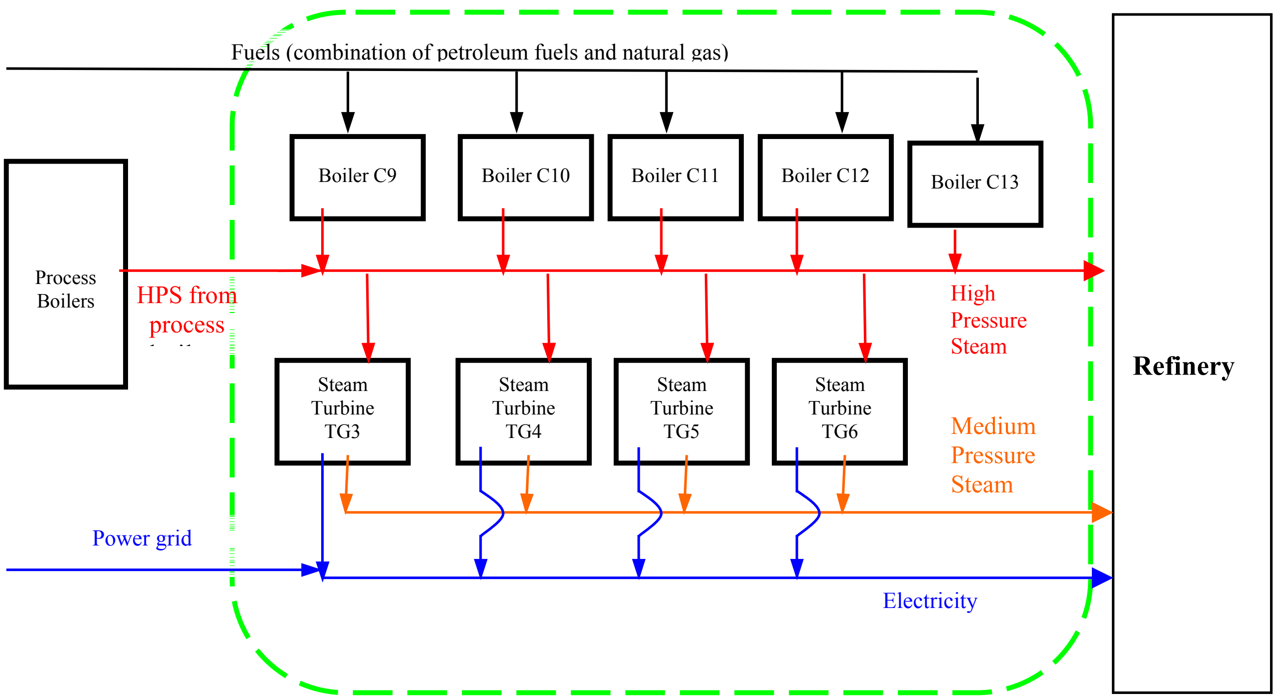

Figure E.1. System boundary and equipment in the baseline situation.

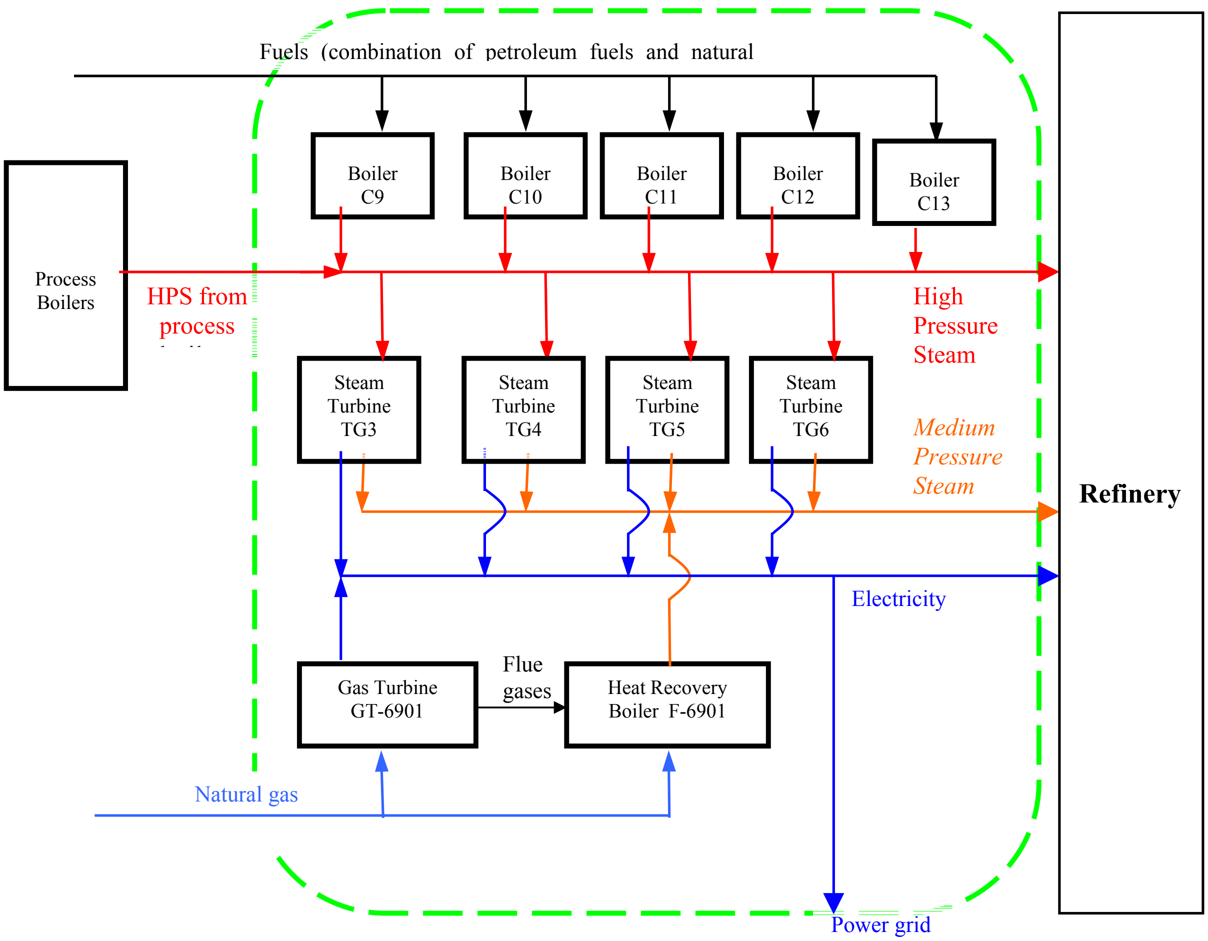

Figure E.2. System boundary and equipment in the project situation.

Fuel combustion in boilers are responsible for GHG emissions within the project boundary in the baseline situation (see Figure E.3). Additional emissions are associated with electricity purchased from the grid.

In the project situation, fuel combustion in the gas turbine and in remaining boilers produce GHG emissions within the project boundary (see Figure E.4). However, since the system now produces excess electricity which is sold through the power grid, this electricity generation offsets emissions from power plants elsewhere in the power grid.

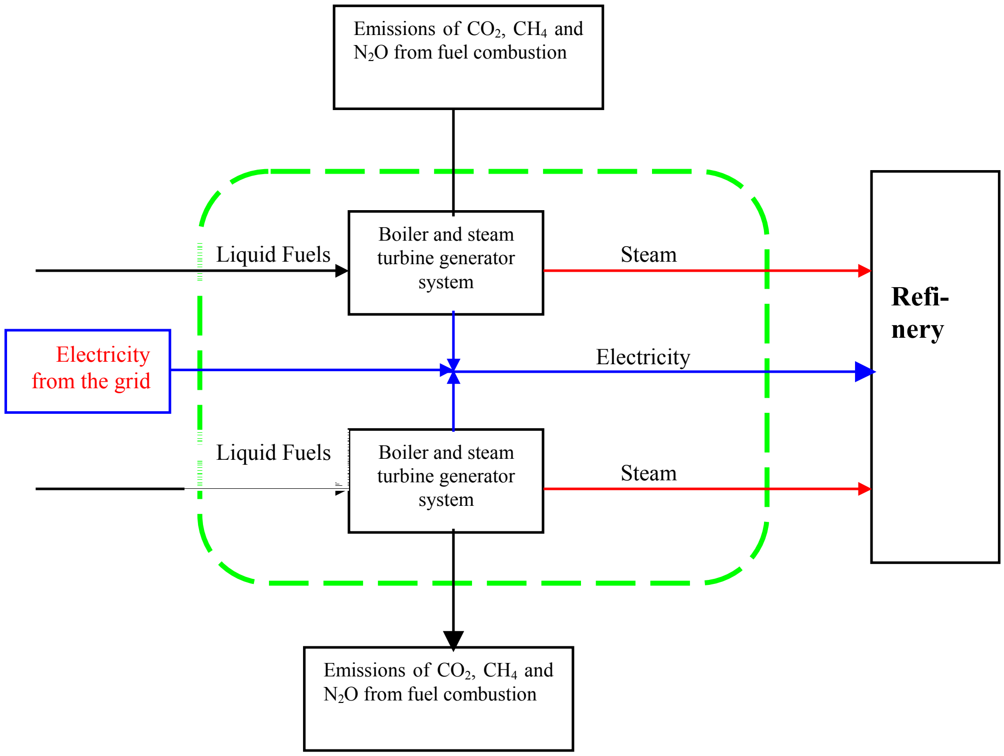

Figure E.3. GHG emissions from fuel combustion within the project boundary in the baseline situation. Additional emissions associated with electricity purchased through the grid are not shown.

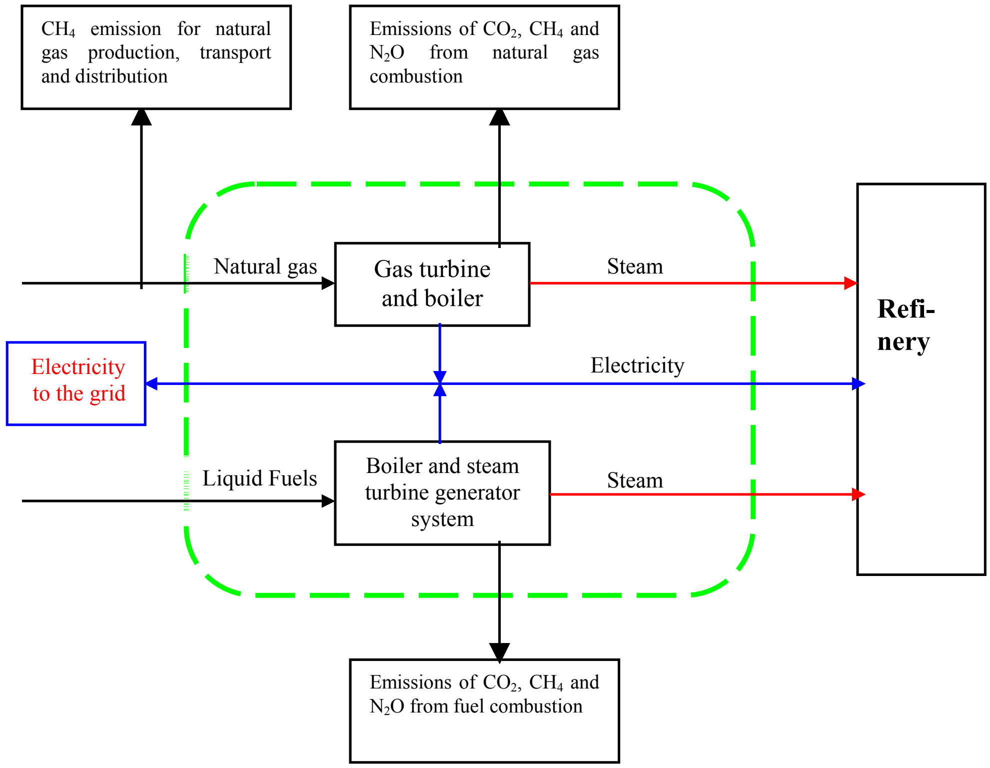

Figure E.4. GHG emissions from fuel combustion within the project boundary in the project situation. Emissions offset elsewhere in the power grid as a result of electricity supplied by the system to the grid are not shown.

In both the baseline and the project situations, GHG emissions within the project boundary correspond to fuels burnt within the boiler room / power station (BRPS). Each of these emissions may be expressed as the product of an emissions factor and fuel energy consumption by equipment within the BRPS.

Each fuel energy consumption is determined from monitored fuel consumption as follows:

Annual energy consumption for each fuel within the project boundary, FC_{fuel} **(GJ/year),** is given by:

$$FC_{fuel}\ (GJ/year) = \frac{MFC_{fuel} \cdot CV_{fuel} \cdot 4.1868\ \text{J/cal}}{10^3} \qquad \textbf{(Eq. E.1)}$$

where MFC_{fuel} = mass fuel consumption of each fuel (ton/yr)
CV_{fuel} = lower heating value of each fuel (kcal/kg), and
Fuel = asphalt, fuel gas, fuel oil, or natural gas

Past fuel consumption data and trends permit a determination of *ex-ante* baseline fuel consumption, considering for instance average fuel consumption over the past 3 years. However, for the proposed project activity, involving four fuels, several boilers and steam turbines, and a gas turbine with heat recovery boiler, *ex-ante* project fuel consumption is best estimated from a thermodynamic analysis of the system. The steam and power flows of the baseline and project configurations are shown in Figs. E.5 and E.6.

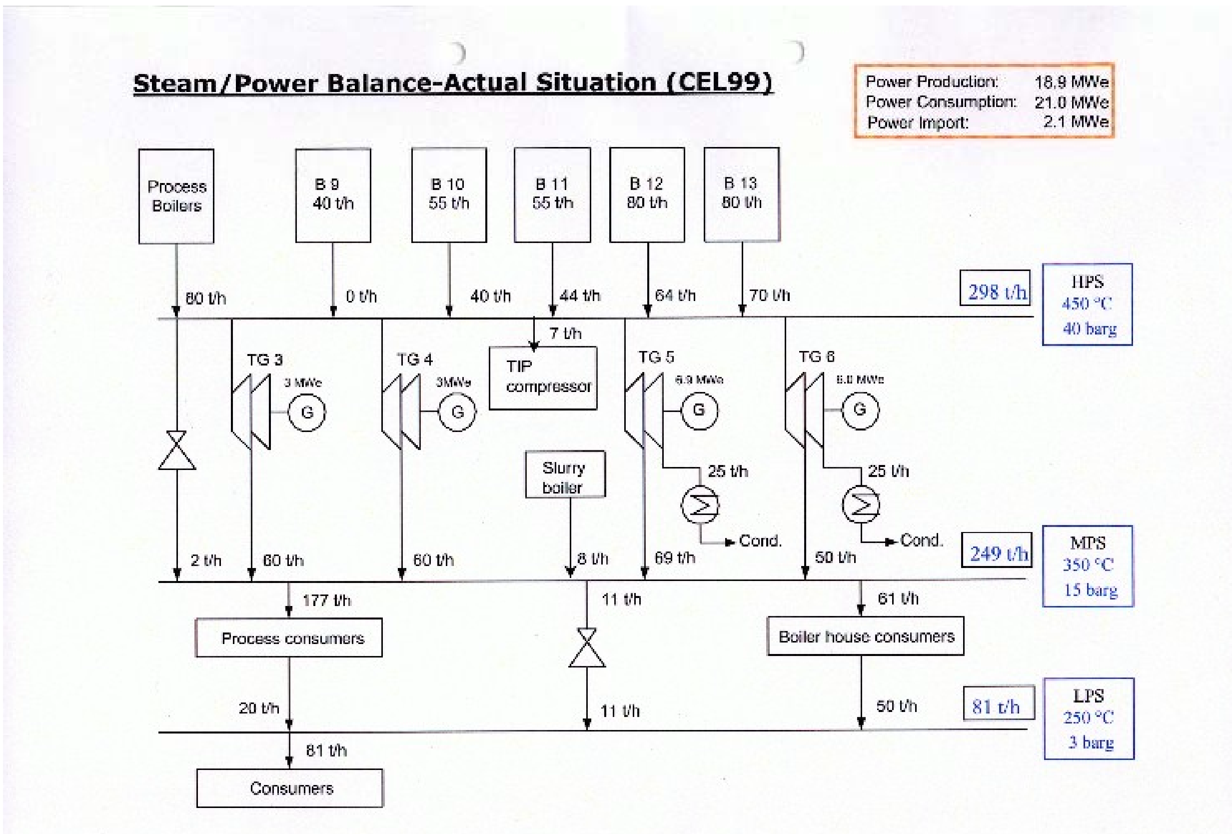

Figure E.5. Baseline configuration

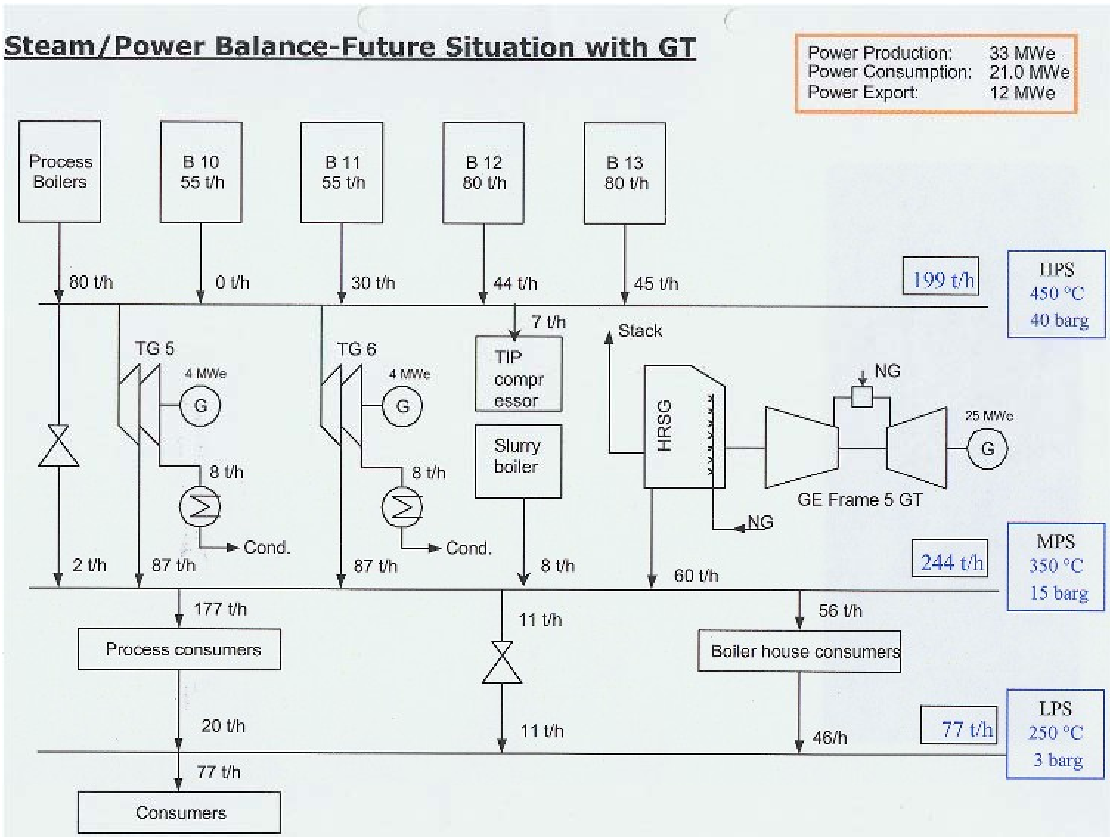

Figure E.6. Project configuration

The principal differences between the baseline and project configurations are summarised here. The introduction of the gas turbine cogeneration system increases overall power generation, from 18.9 MW to 33 MW, converting the plant from being a net importer of 2.1 MW to a net exporter of 12 MW. The refinery power demand is assumed to remain constant at 21 MW. The presence of the gas turbine reduces the need for two steam turbines, with the remaining turbines producing a total of 8 MW. The presence of heat recovered from the gas turbine means that the boilers are required to produce only 199 t/h high pressure steam (HPS), compared to 298 t/h in the baseline situation. This permits three boilers to operate at lower than rated capacity, with a fourth not needed at all. The production of medium and low pressure steam (MPS and LPS) are basically unchanged, there being small reductions (5 t/h and 4 t/h respectively) in internal demand of the boiler house (see bottom right) possibly since the demand for feed water pumping is reduced. Steam obtained as waste heat from refinery activities outside the boiler room / power house and steam delivered to refinery operations remain unchanged, and are not included in this analysis.

The project configuration includes natural gas consumption in the gas turbine.

The estimated natural gas mass consumption by the gas turbine system, *MFC_{ng}* (t /year), is given by**:**

$$MFC_{ng}\ (t\,/\,year) = TFC_{ng}(\max)\cdot CF_{GT}\cdot 8760 \qquad \textbf{(Eq. E.2)}$$

where

TFC_{ng} = Gas turbine natural gas consumption rate (t/h); nominal value = 6.6 t/h,
CF_{GT} = Gas turbine equivalent full-load capacity factor (fraction), and
8760 = no. of hours per year.

Convert to standard refinery fuel consumption (t SRF / year)

$$FC_{ng}\ (tSRF\,/\,year) = \frac{MFC_{ng}\cdot CV_{ng}}{CV_{SRF}} \qquad \textbf{(Eq. E.3)}$$

where

CV_{ng} = lower heating value of natural gas (11,413 kcal / kg), and
CV_{SRF} = lower heating value of Standard Refinery Fuel (9,673 kcal/kg)

For the project configuration, $CF_{GT,}$ *is assumed to be 1, and natural gas consumption would be 68,836 ton SRF/year. See details in spreadsheet Shell_MGM_BSL_ER..*

In the project configuration, fuel consumption takes place in the boilers as well as in the gas turbine. While the heat recovery steam generator includes the possibility of co-firing with natural gas, this is not contemplated in the project configuration. In this case, the boiler production of HPS is reduced to 119 tonnes per hour. With a specific fuel consumption of 8.2 t SRF per 100 t HPS, as before, this fuel consumption amounts to 85,480 t SRF per year, about half the previous value.

SRF is standard refinery fuel, is used as an fuel energy unit at the refinery. The lower heating value of SRF is 9673 kcal/kg.

The boilers normally use asphalt and fuel gas as fuel, with a small amount of fuel oil also used occasionally. Fuel gas is a mixture of refinery gas and natural gas. In terms of calorific value and carbon content, refinery gas is remarkably similar to natural gas. Lower heating values of natural gas and refinery gas are 11413 kcal/kg and 11455 kcal/kg, respectively, while carbon content values are 73.07% y 74.08% w/w. Thus the two fuels (and any blends) have the virtually identical CO_2 emissions factor (on a weight basis, = 56.1 kg CO_2 per GJ).

We estimate consumption of each of the boiler fuels (asphalt, fuel gas and fuel oil) by considering a fixed percentage of overall fuel consumption, where the percentage is determined from historical values. The sheet “consumption profile” in the Excel file Shell_MGM_BSL_ER.xls shows these percentages to be 76.5%, 18.6% and 4.9% respectively. The individual fuel consumption values corresponding to total fuel consumption in the project scenario of 85,480 t SRF/year are given below.

The estimated fuel consumption in boilers, MFC_B (t SRF/year), is given by**:**

$$MFC_{fuel}\,(tSRF\,/\,year) = FC_B * f_{fuel} \qquad \textbf{(Eq. E.4)}$$

where FC_B = HPS production in the boilers (t HPS / year)
f_{fuel} = historical fuel consumption rate fraction of each fuel, where
fuel = asphalt, fuel gas or fuel oil.

The project fuel consumption estimates are:
Asphalt *65,392 t SRF/year*
Fuel gas *15,899 t SRF/year*
Fuel oil *4,189 t SRF/year*

Note that the project configuration also includes natural gas consumption (in the gas turbine) of 68,836 t SRF/year.

Once the fuel energy consumption has been determined from monitoring or estimated *a priori*, emissions may be estimated as described below:

Estimated CO_2e emissions from fuel combustion within the project boundary, $E_{CO_2\,comb}$ **(t CO_2/year),** are given by:

$$E(t\,CO_2\,/\,year) = \sum_{fuel} FC_{fuel} \cdot (EF_{fuel} + MEF_{fuel} \cdot GWP(CH_4) + NEF_{fuel} \cdot GWP(N_2O))$$

(Eq. E.5)

where
FC_{fuel} = annual fuel consumption for each fuel (GJ/year)
fuel = asphalt, fuel gas, fuel oil or natural gas.
EF_{fuel} = CO_2 emission factor for each specific fuel (t CO_2/GJ, lower heating value basis)
MEF_{fuel} = methane emission factor for each fuel combustion (t CH_4/GJ)
$GWP(CH_4)$ = global warming potential of CH_4
NEF_{fuel} = nitrous oxide emission factor for each fuel combustion (t N_2O/GJ)
$GWP(N_2O)$ = global warming potential of N_2O

The *ex-ante* project emissions for each fuel consumption are:
Asphalt 213,917 t CO_2e/year
Fuel gas 36,634 t CO_2e/year
Fuel oil 13,306 t CO_2e/year
Natural gas 158,465 t CO_2e/year

What is the value of *MEF*? Measured values of MEF for each fuel and type of equipment are not available from national data. Indeed, few such data are reported in *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3, Reference Manual.* The closest values are for natural gas industrial boilers or residual fuel oil industrial boilers (Table 1-16, p. 1.54) and natural gas "commercial source" boilers or residual fuel oil "commercial source" boilers (Table 1-19, p. 1.57). In order to be conservative, we take the upper of these two estimate for each fuel. The values adopted are shown in the table below:

Methane Emission Factor$_{fuel}$, MEF_{fuel}	**kg CH_4 /TJ fuel**
MEF_a (asphalt)	3.0
MEF_{fg} (fuel gas)	1.4
MEF_{fo} (fuel oil)	3.0
MEF_{ng} (natural gas)	1.4

We may apply these values of *MEF* to Eq (E.7) to estimate methane emissions from combustion for each fuel consumption in the boiler room and power station in the project scenario. We obtain CO_2-equivalent emissions of 283 tonnes per year. This is insignificant compared to the total project emissions, which add up to over 422,321 tonnes CO_2-equivalent per year (see spreadsheet Shell_MGM_BSL_ER.xls, Sheet "Emiss. Red."). Thus the GHG emissions from methane in combustion is about 0.07 % of total project emissions. *While we include methane emissions in combustion in this PDD, they may well be neglected.*

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*. The values adopted are shown in the table below:

Nitrous Emission Factor$_{fuel}$, NEF_{fuel}	**kg N_2O /TJ fuel**
NEF_a (asphalt)	3.0
NEF_{fg} (fuel gas)	2.3
NEF_{fo} (fuel oil)	3.0
NEF_{ng} (natural gas)	2.3

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 are estimated to be 2,588 tonnes CO_2-equivalent per year, compared to total project emissions of over 422,321 tonnes CO_2-equivalent per year. Thus, nitrous oxide emissions are relatively small, about 0.6% of total project emissions.

The spreadsheet Shell_MGM_BSL_ER.xls details the *ex-ante* calculations of baseline and project emissions, and estimates of emissions reductions. The results are summarized in the last sheet denominated "Emiss. Red.".

Total project emissions from fuel combustion within the project boundary in the project scenario are estimated to be 422,321 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.

Methane leakage from natural gas production. Natural gas that would be used in the project site is extracted in gas fields in the West and South of 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.

Methane leakage from natural gas pipelines and distribution network. Since measured data on pipeline leakage are not available in Argentina, 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 Argentina 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.

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

$$E_{fug}\,(t\ CH_4\,/\,year) = \frac{FC_{ng}\cdot MLR}{10^6} \qquad \textbf{(Eq. E.6)}$$

where FC_{ng} = natural gas consumption (GJ/year)
MLR = methane leakage rate (kg CH_4/GJ of natural gas consumption, LHV basis)

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

$$E_{equiv\ fug}\,(t\ CO_2 - equiv\,/\,year) = E_{fug}\cdot GWP(CH_4) \qquad \textbf{(Eq. E.7)}$$

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

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 **MLR = *0.30 kg/GJ of natural gas energy consumption (lower heating value basis)***.

While the fugitive methane emissions associated with project natural gas consumption are significant, it should be noted that the baseline also involves natural gas consumption in power plants. However, the methodology for grid-connected power generation (ACM0002) only accounts for CO_2 emissions. Thus, we do not include fugitive methane emissions associated with natural gas consumption in the project either. The alternative would have been to include these fugitive emissions in the grid-connected power generation, but since that is based on an approved consolidated methodology (ACM0002), we choose to modify the procedures in this PDD rather than modify ACM0002.

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

>>

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

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

where E refers to CO_2e emissions from combustion of each fuel,

Ignoring leakage, *ex-ante* estimates of total project emissions remain unchanged at 422,321 t CO_2e/year.

During the project, these emissions and reductions with respect to baseline emissions would be determined by actual monitored data of the boiler room and power station.

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

>>

Baseline GHG emissions are determined by the new methodology proposed with this PDD, and applied here.

Baseline GHG emissions *within the project boundary* correspond to emissions from fuel combustion at the boiler room and power station (BRPS) in the absence of the project activity. Baseline emissions comprise the following components:

a) **CO_2e combustion**. CO_2 equivalent emissions from combustion, corresponding to the fuels used in the BRPS, in the baseline situation, i.e. if the gas turbine system did not provide heat and electricity to the refinery.

b) **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 in the baseline. There is a small amount of natural gas used in the baseline situation, mixed with refinery gas, to provide a consistent combustion.

c) **CO_2 from plant electricity deficit in baseline, purchased through the grid**. CO_2 emissions associated with the electricity that would have to be purchased from the power grid in the

baseline situation, since the power output of the boiler room / power station is not enough electricity to meet refinery needs.

d) **CO_2 emissions from surplus electricity provided by project**. With the project situation, there is surplus electricity generation, which is supplied through the power grid. This generation offsets CO_2 emissions elsewhere in the grid, emissions that would be present if the project were not implemented. We consider those emissions as another component of baseline emissions.

The methodology and formulae for estimating each of these components of baseline emissions are described in the new methodology presented with this PDD, and applied below.

The first component (a) of baseline emissions is proportional to fuel consumption of the boilers in the boiler room and power station in the baseline situation. The constant of proportionality depends on the heating value of each fuel, and the emissions factors of the fuel (for CO_2, CH_4 and N_2O from combustion) are expressed as tonne per GJ. The emissions of methane and nitrous oxide need to be converted to equivalent tonnes of CO_2 using their respective GWP.

The second item (b) is proportional to natural gas consumption in the baseline. We estimate this as a proportion of the refinery fuel consumption, using historical data. The constant of proportionality (methane leakage rate, MLR) is the same as explained for project emissions. However, for consistency with ACM0002, we ignore fugitive methane emissions from both baseline and project emissions.

The third item (c) is proportional to the *electricity purchased through the power grid* from the electricity distribution company in the baseline situation. The constant of proportionality is the emissions factor for electricity generation, calculated in Annex 3 of this PDD.

The fourth item (d) is proportional to the *electricity sold through the power grid* in the project scenario. The constant of proportionality is the same emissions factor for grid-connected electricity generation, calculated in Annex 3.

Baseline fuel combustion can be determined from past consumption data. However, we estimate *ex-ante* project fuel consumption using a thermodynamic cycle analysis. For consistency in assumptions on steam flow rates and electricity generation, *ex-ante* estimations of baseline fuel consumption should also be determined from thermodynamic analysis.

In the baseline configuration (see Fig. E.5), the boilers need to generate 218 tonnes per hour of high pressure steam (HPS). Refinery measurements indicate a boiler specific fuel consumption of 8.2 tonnes of SRF (standard refinery fuel) per 100 tonnes of HPS. Note that, while several boilers are involved, refinery measurements indicate that their specific fuel consumption is remarkably constant, reflecting their optimised operation. This corresponds to a boiler fuel consumption of 156,594 tonnes SRF per year.

The boilers use asphalt, fuel gas and fuel oil, and we estimate consumption of each fuel based on the percentages from historic data.

Ex-ante estimates of baseline fuel consumption components are:

Asphalt	119,733 ton SRF/year
Fuel gas	29,153 ton SRF/year
Fuel oil	7,708 ton SRF/year

See details in spreadsheet Shell_MGM_BSL_ER.

Once the fuel energy consumption has been determined from historic fuel consumption or estimated *a priori*, emissions for each fuel consumption may be estimated as described below.

Annual energy consumption for each fuel in the baseline scenario, BFC_{fuel} **(GJ/year),** is given by:

$$BFC_{fuel}\ (GJ\ /\ year) = \frac{MFC_{fuel} \cdot CV_{fuel} \cdot 4.1868\ \mathrm{J/cal}}{10^3} \qquad \textbf{(Eq. E.9)}$$

where MFC_{fuel} = mass fuel consumption of each fuel (ton/yr)
CV_{fuel} = lower heating value of each fuel (kcal/kg), and
fuel = asphalt, fuel gas, fuel oil, or natural gas

Estimated CO_2 emissions from fuel combustion in the baseline scenario, $BE_{CO2\ comb}$ **(t CO_2e/year)** are given by:

$$BE(tonne\ CO_2\ /\ year) = \sum_{fuel} BFC_{fuel} \cdot (EF_{fuel} + MEF_{fuel} \cdot GWP(CH_4) + NEF_{fuel} \cdot GWP(N_2O))$$

(Eq. E.10)

where BFC_{fuel} = annual fuel consumption for each fuel in the baseline (GJ/year)

EF_{fuel} =..CO_2 emission factor for each specific fuel (kg CO_2/GJ, *lower heating value basis*)

MEF_{fuel} = methane emission factor for each fuel combustion (t CH_4/GJ)

$GWP(CH_4)$ = global warming potential of CH_4

NEF_{fuel} = nitrous oxide emission factor for each fuel combustion (tonne N_2O/GJ)

$GWP(N_2O)$ = global warming potential of N_2O

The ex-ante estimates of baseline emissions from fuel consumption are:

Asphalt	391,881 t CO_2e/year
Fuel gas	67,111 t CO_2e/year
Fuel oil	24,375 t CO_2e/year

***EF**$_{fuel}$* depends on the fuel, and is best determined from national data sources, as indicated in the baseline methodology (NMB) presented with this PDD.

As in the case of project emissions, methane emissions from fuel combustion is negligible, while nitrous oxide emissions are relatively small, about 0.3% of total baseline emissions.

The details of project and baseline emissions are to be found in the Excel file Shell_MGM_BSL_ER.xls.

b) CH_4 leaks from natural gas consumption in baseline are not considered here, for consistency, as explained in section E.2.

c) CO_2 from plant electricity deficit in baseline, purchased through the grid.

Prior to project implementation, the refinery purchased electricity from the power grid in order to meet demand. Part of the demand was met by self generation and the emissions associated have been included in the emissions from fuels used within the project boundary. Here we need to account for the emissions that take place at power plants, located outside the project boundary, as a result of electricity purchases by the refinery through the power grid.

Emissions for electricity purchases in the baseline, $BE_{elec,baseline\ purchase}$ are given by

$$BE_{elec,baseline\ purchase} = \frac{NBEP \cdot EF_{elec\ gen}}{1 - TDL} \qquad \textbf{(Eq. E.11)}$$

where

- $NBEP$ = Net baseline electricity purchases (MWh/year),
- $EF_{elec\ gen}$ = Emissions factor for grid power generation (t/MWh) , and
- TDL = Transmission and distribution losses (fraction)

Ex-ante baseline parameters:

Electricity purchases = 2.1 MW x 8760 hours/year = 18,396 MWh/year
EF = 0.365 t CO_2 / MWh
TDL = 0.14

Applying the formulae above,

$BE_{elec,baseline\ purchase}$ = *7,807 t CO_2e/year*

d) Baseline CO_2 emissions from surplus electricity provided by project to the grid.

Following project implementation, the generation capacity at the refinery would be greatly increased, exceeding refinery demand. Excess electricity would be sold through the power grid. In the absence of the project activity, i.e. in the baseline, this electricity would have to be generated by other power plants in the power grid. Thus baseline emissions would increase following project implementation.

Baseline emissions for electricity sold in the project scenario, $BE_{elec,\ project\ sales}$ are given by

$$BE_{elec,\ project\ sales} = NPES \cdot EF_{elec\ gen} \qquad \textbf{(Eq. E.12)}$$

where

- $NPES$ = Project electricity sales (MWh/year) and
- $EF_{elec\ gen}$ = Emissions factor for grid power generation, as in Eq. E.14.

Ex-ante project parameters:

Electricity sales = 12 MW x 8760 hours/year = 105,120 MWh/year
EF = 0.365 t CO_2 / MWh

Applying the formulae above

$BE_{elec,\ project\ sales}$ = *38,369 t CO_2e/year*

The emissions factor for grid power generation, $EF_{elec\ gen}$, is determined using the approved consolidated methodology ACM0002, as shown in Annex 3.

As we have mentioned before, *ex-ante* baseline and project emissions are also to be found in the spreadsheet Shell_MGM_BSL_ER.xls.

Ex-ante baseline emissions are estimated to be 529,544 tonnes CO_2equivalent per year.

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

>>

Emissions reductions are determined *ex ante* using the spreadsheet Shell_MGM_BSL_ER.xls.

Ex-ante emissions reductions are estimated to be 107,222 tonnes CO_2equivalent per year.

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

>>

The *ex-ante* emissions reductions are estimated to be 107,222 tonnes CO_2equivalent per year. Note that this is constant over time. However, actual emissions reductions will be based on monitored data and are likely to be different from this estimate, and vary in time.

SECTION F. Environmental impacts

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

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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:

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SECTION G. Stakeholders' comments

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As indicated in the instructions from the CDM Executive Board, Stakeholder comments are not required for PDDs submitted with new methodologies, as is the case here.

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

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G.2. Summary of the comments received:

>>

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

>>

Annex 1

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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 INFORMATION

Most of the assumptions related to the determination of baseline emissions were provided in the relevant sections of the PDD. In this Annex, we limit ourselves to summarising the procedure used to determining the emissions factor of grid-connected electricity generation, $EF_{elec\ gen}$.

In the baseline situation, the refinery purchases electricity through the power grid, and in the project situation, electricity is sold through the power grid. In the first case, electricity generation elsewhere required to supply the refinery leads to additional emissions than those accounted for in the project boundary. In the second case, the project actually supplies electricity to the grid, thus offsetting emissions elsewhere. By CDM tradition, these emissions offset are considered as baseline emissions, in the sense that such emissions would take place if the project did not supply electricity to the grid.

A number of methodologies have been submitted by CDM project developers to determine emissions factor that would be offset by renewable electricity. Upon revision of these methodologies, the Meth Panel has published the so-called "Consolidated baseline methodology for grid-connected electricity generation from renewable sources." Following the 15th Meeting of the CDM Executive Board in early September 2004, this methodology was formally approved and designated ACM0002[5] (ACM = Approved Consolidated Methodology).

At the same time, the Meth Panel and the CDM Executive Board also indicated that for the electricity offset by a cogeneration system, the same consolidated methodology be used, even though the project did not deal with generation using renewable sources. In this regard it is useful to note that if project emissions from electricity generation or cogeneration using non renewable resources are properly taken into account, then the baseline emissions refer to the emissions offset by this generated electricity is no different from the case in which the generation were from renewable sources. Thus, the Methodology Panel and the CDM Executive Board is entirely correct in not treating separately these baseline emissions.

ACM0002 indicates that the emissions factor is a so-called "combined margin", which is determined in three steps:

1. **Calculate the Operating Margin emission factor**
2. **Calculate the Build Margin emission factor**
3. **Calculate the baseline emission factor Combined Margin** as the weighted average of the Operating Margin emission factor and the Build Margin emission factor

Four different procedures are indicated for determining the operating margin. These are denominated:

(a) Simple Operating Margin
(b) Simple Adjusted Operating Margin
(c) Dispatch Data Analysis Operating Margin
(d) Average Operating Margin.

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[5] Approved consolidated baseline methodology ACM0002 "Consolidated baseline methodology for zero-emissions grid-connected electricity generation from renewable sources", Published as Annex 2 of the report of the 15th Meeting of the CDM Executive Board, Sept 3, 2004.

Three of these procedures (a, b and d) are relatively simple, but one procedure (c-dispatch analysis) requires access to an inordinate amount of data on the operation of all power plants in the grid connected to the project in question, on an hour-by-hour basis, for the entire project lifetime. Data at this level are not available to the public. To perform a dispatch analysis, we would need to know:

- which power plants were dispatched for each hour during the entire monitoring period;
- what the merit order of dispatch was, which depends on the fuel efficiency and fuel prices for thermal power plants, the availability of dispatchable hydroelectric power plants, as well as knowledge of system operation in order which power plants out of merit order need to be dispatched in order to meet system and voltage stability requirements, as well as because of transmission bottlenecks. and voltas far which power plants are required.

The procedure is further complicated by the fact that:

- fuel prices vary; generators may declare values below market prices and may do so, for instance where they have “take or pay” contracts with fuel suppliers, in order to see their equipment dispatched;
- there are restrictions on natural gas availability especially during winter months;
- some power plants can operate on alternative fuels, others not;
- fuel price changes, fuel switching or system stability problems can all affect the merit order

Moreover, hour-by-hour dispatch analysis provides a valid answer to which power plants are offset by the project generation only for power grids where there is no appreciable energy storage. Electricity is “stored” indirectly b y storing water in reservoirs, whose height can be varied over the course of hours, days, or even months in order to take into account both demand variations as well as seasonal rains. Specifically, in Argentina, dispatchable hydroelectric power plants make a significant contribution to meeting demand during the peak evening hours. Dispatch analysis would indicate that 1 MW by a project activity during a peak hour would mostly displace hydro. This is not true, since the water saved at that hour will not simply be spilled out. The water would be saved and used at another hour, where it would offset higher cost generation based on fuel combustion. Since fossil-fuel power plants are used for all hours, the power plants offset would always be thermal power plants.

In many non-Annex 1 countries, there are large amounts of such “dispatchable” hydro, whereby hydroelectric generation may offset emissions from a thermal power plant at another time.

The problem of determining which power plant in the power system is offset by project generation becomes even more complex when reservoir water storage extends over longer periods. Many non Annex 1 countries have rainy and dry seasons, and hydroelectric reservoirs are designed to carry over water from rainy to dry seasons.

Hydroelectric power plants are dispatched not according to a merit order expressed in terms of specific fuel consumption and fuel price, but rather than on a model of optimal management of water resources. The water flow from a given reservoir affects water availability and power generation potential of power plants downstream. Moreover, water is often also used for irrigation, which places other restrictions on how water is stored in or released from a reservoir.

In many Annex 1 countries, the hydroelectric resources are largely saturated, and make up a small part of total generation. Thus supply and demand are matched by an hour-by-hour balancing of thermal power plants available and power demand. In such cases, an hourly dispatch analysis could provide a reasonable estimate of power plants offset by hourly generation from a given project activity.

In any system with significant amounts of dispatchable hydro, such as the case for Argentina, an hour-by-hour analysis can lead to an erroneous estimate of emissions avoided from the power grid through power generated by a given project activity.

ACM0002 states:

> *"Dispatch data analysis should be the first methodological choice. Where this option is not selected project participants shall justify why and may use the simple OM, the simple adjusted OM or the average emission rate method taking into account the provisions outlined hereafter."*

We have argued above that dispatch analysis based on hourly data is not appropriate for power generation connected to the Argentine power grid. A more reliable estimate can indeed be obtained from the Simple Operating Margin or the Adjusted Simple Operating Margin approaches described in ACM0002. The results are presented below:

Simple Operating Margin

ACM0002 states that the Simple OM method can only be used where low-cost/must run (LCMR) resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term normals for hydroelectricity production.

ACM0002 further states:

> *Low operating cost and must run resources typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must-run, it should also be included in this list, i.e. excluded from the set of plants.*

In the case of Argentina, LCMR would include nuclear power plants and run-of-river hydropower plants that do not allow water storage, and are therefore not dispatched. To this list, one would also add self-generation equipment at industrial sites, which declare zero marginal cost in order to be always dispatched. We would also include power plants that are forced to operate, despite being not included in economic dispatch, for a variety of reasons such as for system and voltage stability (denominated S&T) or for other reasons[6].

The energy generation of power plants in the national grid of Argentina, according to these categories, are shown in Table 3.1.

[6] These other reasons include: (a) equipment start up, (b) operating cost for start up and stopping (when it is cheaper to keep a forced generator operating than to start up another one; (c) for requirements of downstream power plants; (d) for generator trials, (e) for time for start up and stopping, (f) forced by the distribution company for saturation of its sub-transmission equipment, (g) forced by power requirement in a given area (and transmission bottlenecks), (h) generating equipment that become unavailable, etc.

Table 3.1. Electricity generation and emissions by type of power plant in the Argentina national grid.

Type of generation	Source	Year of data July 2003 to June 2004 Generation (MWh)	Emissions tCO_2	Emission factor (tCO_2/MWh)
Forced S&T	Hydro	12,000	0	0.000
	Fuel oil	88,277	69,422	0.786
	Natural gas	454,013	282,085	0.621
	"Gas oil"	7,942	7,806	0.983
Other forced	Hydro	1,902,556	0	0.000
	Coal	147,747	148,821	1.007
	Fuel oil	365,753	291,656	0.797
	Natural gas	1,379,859	626,549	0.454
	"Gas oil"	47,461	31,582	0.665
Dispatched	Hydro	10,854,759	0	0.000
	Coal	421,775	424,841	1.007
	Fuel oil	2,218,527	1,753,459	0.790
	Natural gas	35,431,664	15,184,697	0.429
	"Gas oil"	316,875	181,972	0.574
Zero oper. cost (Low-cost / must-run)	Uranium	7,147,326	0	0.000
	Base Hydro	19,804,557	0	0.000
	Self generation & cogeneration Natural gas	5,745,777	2,504,351	0.436

Note: "Gas oil" is light diesel (distillate).

The energy generation of all power plants connected to the Argentina MEM grid is reported monthly by the wholesale power management company (CAMMESA). Each thermal power plant must report the specific fuel consumption for their equipment. This is a function of load factor and is expressed as a polynomial. However, in this analysis we consider the full-load or nominal values, in order to determine fuel consumption corresponding to reported electricity generation data. The fuel consumption values are multiplied by the CO_2 emissions factors for the fuels involved in order to estimate total emissions for each power plant. Monthly values are summed to provide annual totals. The values in Table 3.1 correspond to the period from July 2003 to June 2004.

Data from different power plants are grouped into the categories shown in the first column of Table 3.1, and summed to show the total electricity generation and total CO_2 emissions of each category using each energy source. The ratio of emissions (tCO_2/year) to power generation (GWh/year) is the emissions factor. The resulting values are shown in the last column of Table 3.1.

Note that Low-cost /must-run electricity generation added up to 32,697,660 GWh out of a total of 86,346,867. Thus LCMR represents 38% of the total, which is less than 50%, and the Simple Operating Margin approach is applicable, as per ACM0002.

While the data in Table 3.1 are from a recent one-year period, Figures 3.1 and 3.2 respectively show that absolute and relative contributions of thermal, hydro and nuclear generation to the total.

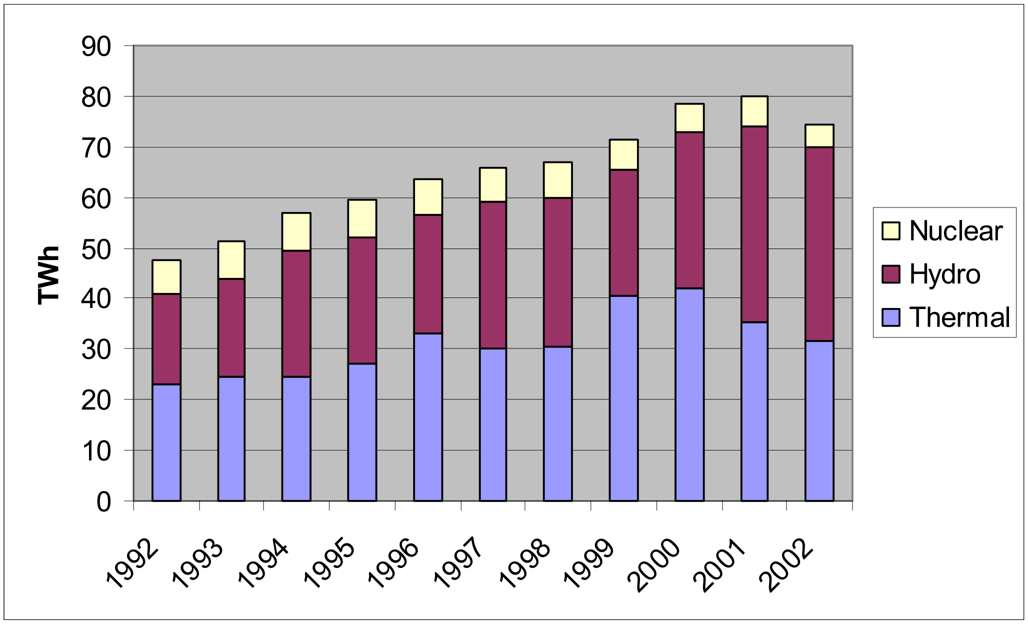


Figure 3.1. Thermal (grey, bottom), hydro (purple, medium) and nuclear (cream, upper) electricity generation in Argentina, from 1992 to 2002. Demand growth ceased in 2001 and demand actually fell during 2002. Higher rainfall in 2001 and 2002 meant that thermal generation fell sharply in 2001 and 2002.

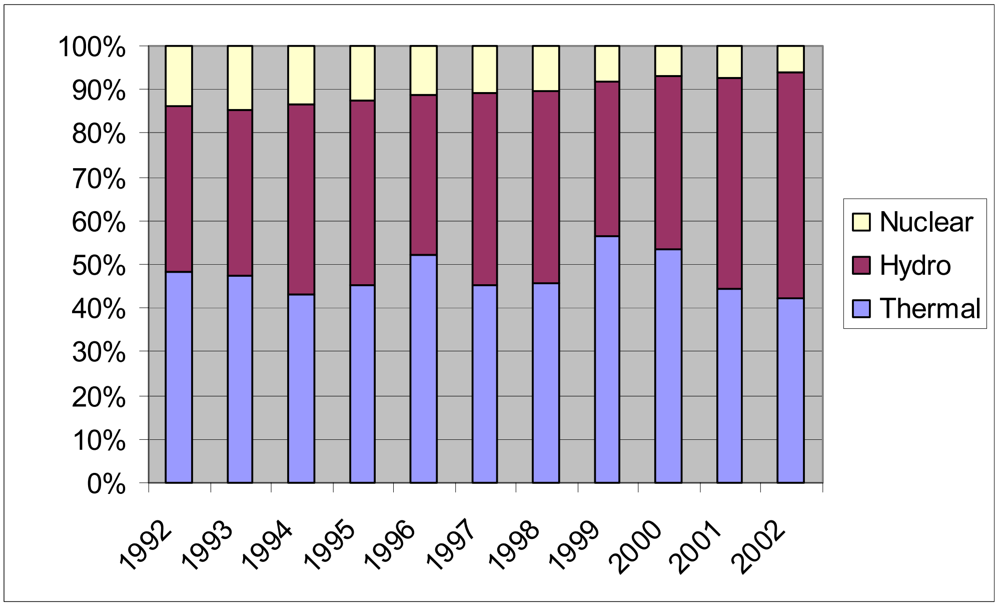


Figure 3.2. Relative contribution of thermal (grey, bottom), hydro (purple, medium) and nuclear (cream, upper) electricity generation in Argentina, from 1992 to 2002. On average, about half of total generation is from thermal power plants using fossil fuels. Somewhat under half of hydro may be considered low-cost /must-run (LCMR), so that this component, together with nuclear electricity make up less than half of total generation in any of these years.

Excluding LCMR power generation (as defined above), we determine that total generation of 49,243,599 MWh resulted in total emissions of 17,544,968 t CO_2 equivalent, so that the emissions factor corresponding to the operating margin is 0.356 tCO_2/MWh.

Alternatively, we may consider the LCMR power plants to be strictly the nuclear power plants and the run-of-the-river hydro. In this case, total generation of 59,394,985 MWh resulted in total emissions of 21,507,240 t CO_2 equivalent, so that the emissions factor corresponding to the operating margin would be 0.362 tCO_2/MWh.

This value is not substantially different from the operating margin calculated using the previous assumption. In order to be conservative we choose the previous estimate of **0.356 tCO_2/MWh** as the operating margin for power generation in this grid.

Simple Adjusted Operating Margin

This is a variation of the Simple Operating Margin, where the power sources (including imports) are separated in low-cost/must-run power sources and other power sources. We are required to determine what fraction of time, the low-cost/must-run power plants are on the margin. See Figure 3.3.

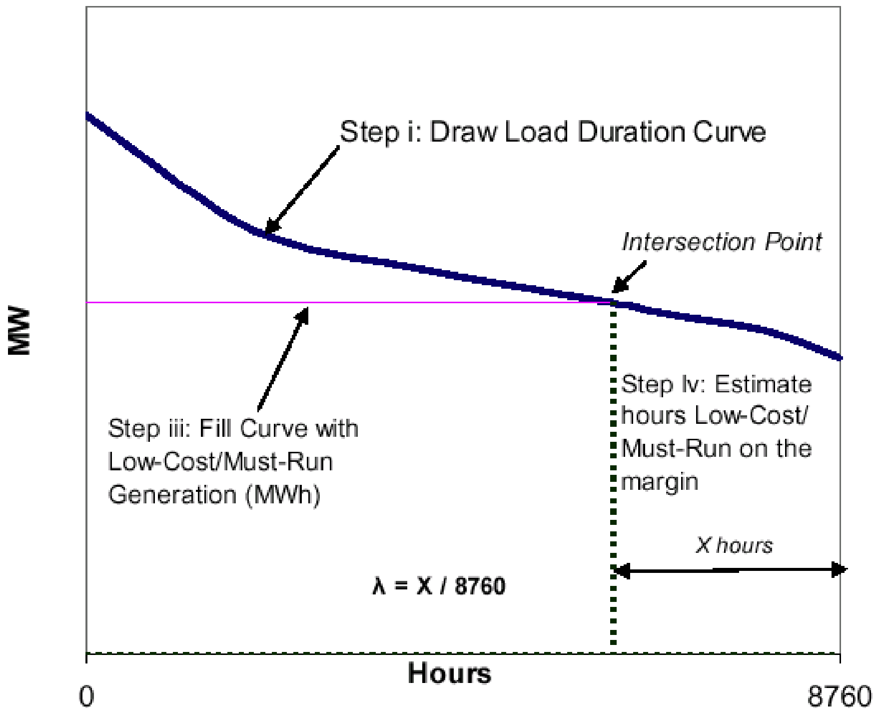
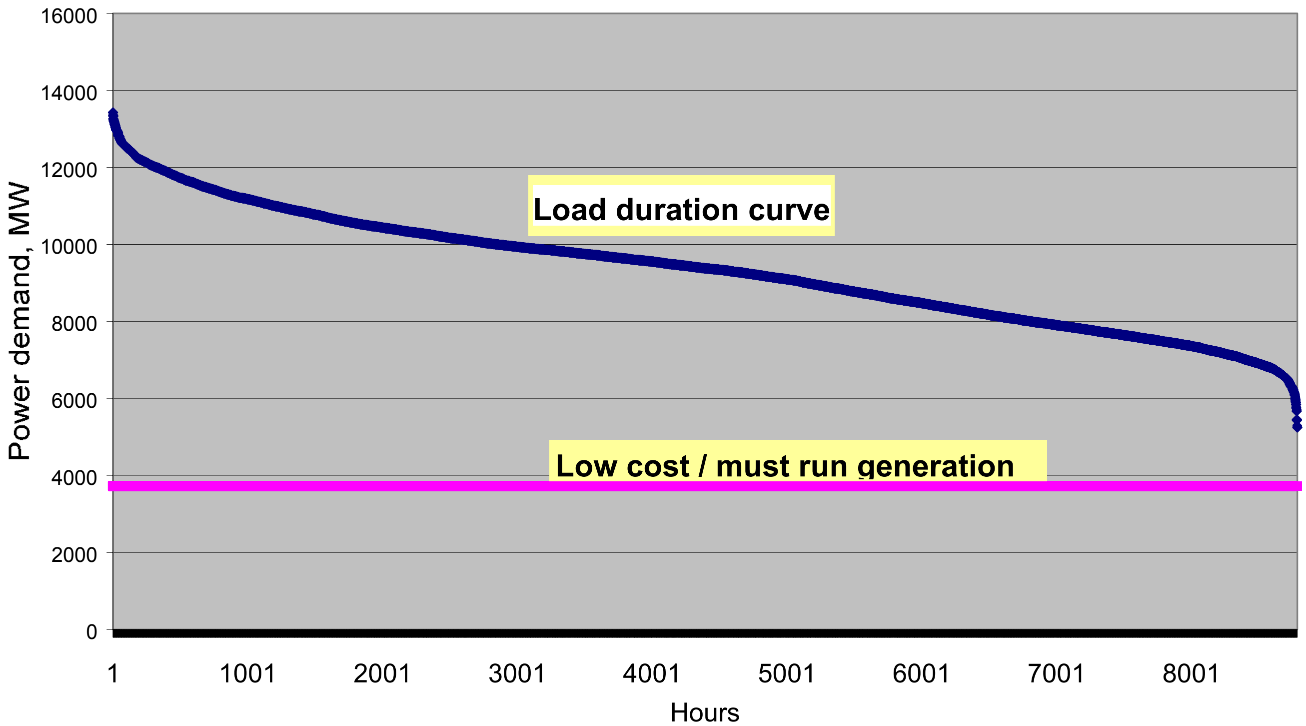


Figure 3.3. Determination of lambda (λ) as fraction of total hours in a year that low-cost / must-run (LCMR) generation sources are at the margin. The value of λ is given by the intersection of the load duration curve and the supply from LCMR power plants (horizontal line, magenta). (Source: Fig. 1 of ACM0002.)

This figure for the national power grid of Argentina is shown in Figure YY, where we can see that the intersection takes place on the right vertical axis. In other words, LCMR power plants never operate at the margin, and λ = 0. In this case, there is no difference between the Simple Operating Margin and the Adjusted Operating Margin.



Step 2. Calculate the build margin

According to ACM0002, the build margin is determined by the average emissions factor of a sample of recently built power plants. The sample may be the most recent five power plants built if they add up to more than 20% of the total generation in the grid. If not, the sample must include enough of the most recently built power plants in order that together they represent at least 20% of the total generation.

While this procedure appears straightforward, its application raises a number of problems, at least for the Argentina national grid. As we have mentioned in Section B.3, both the macroeconomic situation in Argentina and the rules for the operation of the wholesale power market have inhibited the construction of new power plants. Most recent power plants have in fact been adding components to power plants already started. Typically these are natural gas-fired combined cycle power plants which comprise two gas turbine power plants and a steam turbine power plant. The installation of each component is listed as a "new construction" with its output power reported. However, the wholesale market sees all components as a single power plant and only reports the total energy output from the system, independent of the number of components that may be installed and operating at any given time.

Moreover, the emissions factor of individual components is not relevant since waste heat from the gas turbines is recovered and used in steam turbines. Thus the specific fuel consumption of the entire system is lower than that of any of its component parts. For this reason, we have considered, as a conservative assumption, that all portions of combined-cycle power plants recently installed would have the emissions factor as if the power plant was operating in combined cycle. Characteristics of principal power plants added in recent years are shown in Table 3.2 below.

Table 3.2. Recent power plant constructions in the MEM power grid, Argentina

Entry date Year Mon.	Power plant	Type	Power MW	Specific cons. kcal/kWh	Generation GWh	Generation Acum	Generation Acum %	Fuel consumption TJ	Fuel consumption Acum TJ	Cum. Spec. Cons. TJ/GWh	Cum. Emis. Factor kg/MWh
2004apr	San Nicolás	GT	24.0	3176	0.0	0.0	0%	0	0		
2003	AES Caracoles (Q Ullum)	Hydro	45.0		192.0	192.0	0%	0	0	0.00	0.0
2003	Consorcio Potrerillos (A. Condarco)	Hydro	74.0		253.0	445.0	1%	0	0	0.00	0.0
2003jun	Pluspetrol Norte	GT	116.4	2613	117.6	562.6	1%	1287	1287	2.29	128.3
2002dec	Consorcio Potrerillos (Cacheuta N.+El Carrizal)	Hydro	96.0		156.9	719.5	1%	0	1287	1.79	100.3
2002nov	Petrolera Chevron San Jorge	GT	18.5	3500	146.0	865.5	1%	2140	3426	3.96	222.1
2002aug	San Miguel de Tucuman	CC	250.0	1725	1645.1	2510.6	3%	11881	15307	6.10	342.0
2002aug	Consorcio Potrerillos (El Carrizal)	Hydro	17.0		70.8	2581.3	3%	0	15307	5.93	332.7
2002jun	Pluspetrol Norte	GT	116.4	2613	117.2	2698.5	3%	1282	16589	6.15	344.9
2002mar	San Miguel de Tucuman	GT	124.0	1725	815.9	3514.4	4%	8927	25516	7.26	407.3
2001nov	AES Paraná	CC	830.0	1508	3944.0	7458.4	9%	24901	50417	6.76	379.2
2001oct	San Miguel de Tucumán	CC	382.0	1725	2294.0	9752.4	12%	16568	66985	6.87	385.3
2001jun	Dock Sud	CC	773.0	1528	4208.0	13960.4	17%	26920	93905	6.73	377.4
2000may	Puerto Nuevo	CC	798.0	1487	4839.0	18799.4	23%	30127	124031	6.60	370.1
2000sep	Autogenerador Entre Lomas	GT	15.0	3252	23.0	18822.4	23%	313	124344	6.61	370.6
1999sep	Costanera	CC	851.0	1486	4838.0	23660.4	29%	30100	154444	6.53	366.2
1999oct	Agua del Cajón	CC	662.0	1808	4477.0	28137.4	34%	33890	188334	6.69	375.5

Notes: GT: open-cycle gas turbine; CC: combined cycle plant.

Some power plants can operate on more than one fuel. Indeed, in the winter, the demand for natural gas peaks because of space heating demand, and gas pipelines become saturated. In these periods, some power plants (and industrial consumers with interruptible gas supply) of natural gas switch to liquid fuels, especially fuel oil or diesel, depending on the power plant equipment involved. Thus, power plants that make up the build margin do not have a single emissions factor, rather, the factor depends on the fuels actually used. However, in order to be further conservative, we have assumed that natural gas is used in all cases.

Actual generation is shown for each power plant for the period Sept. 2003 to Aug. 2004. The total generation for this period was 81,648 GWh. The % contribution of each of the power plants listed to this total are also shown in the table above. The power plants are listed in reverse chronological order of coming on line adding up to 34% of total generation.

The power plants Dock Sud (17%) and Puerto Nuevo (23%) bracket the methodology requirement to include 20% of the total generation.

The last column in the table shows the cumulative average emissions factor of power plants in reverse chronological order. The values corresponding to power plant including Dock Sud and Puerto Nuevo are 377.4 and 370.1 kg CO_2 per MWh. The average of these values is 373.7 kg CO_2/MWh.

Thus the build margin emissions factor for baseline power generation is **0.374 t CO_2/MWh**.

Step 3. Calculate the baseline emissions factor.

The consolidated methodology ACM0002 indicates that the emissions factor is a weighted average of the operating margin and the build margin, suggesting a 50/50 weighting.

One could argue that for generation, cogeneration or electricity end use efficiency at power levels small compared to installed capacity, a higher weighting should be given to the operating margin and a corresponding lower weighting to the build margin. In this case, however, there is hardly any difference between the operating margin (0.356 t CO_2/MWh) and the build margin (0.374 t CO_2/MWh). Thus we consider a 50/50 weighting rounding towards the operating margin, and we estimate the combined margin to be **0.365 tCO_2/MWh.**

Annex 4

MONITORING PLAN

Monitoring is required for the following purposes:

- To determine the emissions factor for power generation in order to determine the emissions offset by power generation in the project activity and sold through the power grid offsetting generation elsewhere.
- To determine project emissions, from fuel consumption at the project site, including that used for generating electricity sold through the power grid.
- To determine baseline emissions in a dynamic manner

The monitoring plan for each of these items is described below.

Emissions factor for grid-connected power generation

The monitoring requirements correspond to the Approved consolidated monitoring methodology ACM0002 "Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources."

ACM0002 refers to grid-connected renewable energy projects and requires the monitoring of:

- Electricity generation from the proposed project activity;
- Data needed to recalculate the operating margin emission factor, if needed, based on the choice of the method to determine the operating margin (OM), consistent with "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" (ACM0002);
- Data needed to recalculate the build margin emission factor, if needed, consistent with "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" (ACM0002);

This specific project involves cogeneration at a refinery, where a part of the electricity generated would meet local power requirements. Moreover, when the cogeneration equipment is under maintenance the refinery would need to purchase electricity from the power grid. Both power sales to the grid and power purchases from the grid would affect emissions elsewhere in the grid. Thus, both sales and purchases need to be monitored and net electricity sales (sale minus purchase) needs to be recorded.

Determining the operating margin emissions factor requires data on the generation of each power plant supplying the project power grid. These are divided into four categories: "zero price", forced "S + T", other forced, and dispatched (see Table 4.1 below). For each category, we obtain electricity generation and fuel consumption data from the national dispatch centre, CAMMESA. Emissions can be determined directly, based on the CO_2 emissions factors for the fuels involved, here coal, fuel oil, diesel, and natural gas. The Table YY needs to be completed for each year of data for the monitoring period.

All except "dispatched" comprise low cost / must run power plants. Using the simple OM approach, the operating margin emissions factor for the year in question is given by the ratio of the total emissions from the "dispatched" power plants and the electricity generated by these power plants during the year.

Table 4.1 Data table for determining operating margin emissions factor.

Type of generation	Energy source	For each year of data		
		Generation (MWh)	Total fuel consumption	Emissions tCO_2
Zero price	nuclear			0
	base hydro			0
	self/cogeneration natural gas			
Forced S+T	hydro			0
	fuel oil			
	natural gas			
	diesel			
Other forced	hydro			0
	coal			
	fuel oil			
	natural gas			
	diesel			
Dispatch	hydro			0
	coal			
	fuel oil			
	natural gas			
	diesel			
	TOTAL			

"S + T" refers to forced generation required for system and voltage stability.
"Other forced" refers to the following:

1. Equipment startup
2. Operating costs for start and stop, when it is cheaper to keep a generator operating
3. For downstream water requirements
4. For generator trials

Determining the build margin emissions factor requires similar data as above, except, in this case we also need the date each new power plant comes on line. We need to obtain date on the total generation of each of the new power plants until we reach 20% of the total generation for the year in question. The procedure described in the previous Annex will need to be repeated for each year of crediting period.

Once operating margin and build margin emissions factors have been determined, the combined margin emissions factor may be readily determined as the arithmetic mean of the two values, as was shown in Annex 3, for *ex-ante* determination of this emissions factor.

Project emissions

Project emissions correspond to CO_2 emissions from fuel consumption within the project boundary. These emissions depend on the type and quantity of fuels used. The emissions factor for each fuel type (e.g. t CO_2/GJ) depends the carbon content of the fuel. These factors are determined from national data.

Fuel combustion also produces very small amounts of methane and nitrous oxide. Again emissions depend on type and quantity of fuels used, as well as the type of equipment involved. In this case, the emissions factors are based on IPCC reference values for equipment similar to those involved, since there are no national values available, and the overall emissions of these gases, in equivalent CO_2 terms is very small compared to the CO_2 emissions.

Monitoring thus involves recording the consumption of each fuel on a monthly basis, with periodic calibrations of measuring equipment involved. These are part of existing procedures at the Shell refinery for fuels used in the baseline and which would continue to be used following project implementation. The fuels are asphalt, fuel gas and fuel oil.

The project activity also requires natural gas to be purchased from the gas pipeline. In this case, the natural gas supplied to the project activity needs to be measured monthly using a calibrated flow meter following protocol and standards applicable to natural gas sale in the Argentina natural gas market, as specified by the National Regulatory Agency (ENARGAS).

For the determination of CO_2 emissions, the total consumption of each fuel on a monthly basis is sufficient. However, CH_4 and N_2O emissions can be equipment specific. Although these emissions are very small, if equipment specific fuel consumption data are available, also on a monthly basis, this would be preferable.

The baseline methodology provides two alternatives for determining baseline emissions: fixed emissions if past fuel consumption patterns demonstrate that consumption has been constant in recent years. This is indeed the case for the project in question. See the page "refinery demand" of the Excel workbook "Shell_MGM_BSL_ER.xls", which shows that fuel consumption, as well as steam demand and electricity consumption have been constant over the three years prior to project implementation. This is not surprising since the industry in question is a refinery which is optimised to operate at its maximum capacity. Therefore we may use a fixed baseline emissions based on the average for these three years.

As far as electricity is concerned, the baseline assumes that the same amount of electricity would be purchased from the grid as prior to project implementation. This can be converted to emissions using the grid emissions factor as determined above.

Emissions reductions

Once the emissions factor for grid-connected electricity generation has been determined, and project and baseline emissions have been calculated, emissions reductions can be readily determined.

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