CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

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SECTION A. General description of project activity

A.1 Title of the project activity:

Integrated Energy Ltd. Grid Connected Electricity Generation Plant using Natural Gas
Version 2
January 7, 2008

A.2. Description of the project activity:

A.2.1. Project Summary
Energy consumption is rapidly increasing in Israel due to its relatively high population growth and rising standard of living.

Energy consumption in Israel has grown rapidly over the past two decades due to population growth, which increased annually by an average of 2% between 1996 and 2005.[1] During this period of time the average annual increase in electricity consumption was 5%.[2] In fact, in recent years electricity demand in Israel has risen to such an extent that on some days demand nearly meets the entire production capacity of the grid. In late June 2007, electricity demand hit 10,040 MW when the total generating capacity in Israel is 10,500.[3] This places enormous pressure on the power stations because problems in one generator will lead to blackouts across the country. The Ministry of National Infrastructure anticipates that in 20 years, the demand for electricity in Israel will double.

Currently, the electricity generated in Israel is mostly produced by coal-fuelled power plants. Data available from the Israel Electric Company (IEC) specifies that in 2005, 75% of electricity in the country was generated by coal. There is a trend towards a decrease in HFO and diesel consumption and a slight increase in the use of natural gas.

The increased demand for electricity and the shrinking available electricity reserves in Israel prompted the government to liberalize the electricity market by opening it to private producers, with the intention of increasing electricity generating capacity in the country. The main electricity utility in Israel is the Israel Electric Company (IEC), a government company, with a maximum generating capacity of 10,500 MW. The Ministry of National Infrastructure and the government are seeking to increase electricity generation in Israel by providing private producers with licenses for large-scale electricity production. As well, the Electricity Authority (a government body that oversees the electricity sector) requires the IEC to purchase electricity from private producers at a fixed price (which varies depending on the hour of the day).

The project activity is the construction of a new grid-connected combined cycle co-generation natural gas power plant. The plant will contain one gas turbine (with a nominal power of 150 MW) for the

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[1] Central Bureau of Statistics. Statistical Abstract of Israel, 2006. Table 2.1, p.85-86. http://www1.cbs.gov.il/reader/. Accessed August. 19, 2007.

[2] Israel Electric Company, *Statistical Report, 2005.* http://www.iec.co.il/Static/WorkFolder/IRR/Statistic%20Report%202005.pdf. p.23.

[3] "Peak Electricity Demand", *NRG News Service.*. July 29, 2007. Translation provided to DOE.. http://www.nrg.co.il/online/16/ART1/614/920.html. Accessed August 28, 2007.

production of electricity; one Heat Recovery Steam Generator; one single entry steam turbine (with a nominal power of 70MW), which will generate electricity from the waste heat; waste heat (steam) from the steam turbine will be sold to the American Israel Paper Mills.

The power plant will be constructed by Integrated Energy Ltd., an affiliated company of the American Israel Paper Mill (AIPM) Company, the leading Israeli manufacturer and marketer of paper products and a recycling pioneer and the main recycling player in Israel. The power plant will supply steam and approximately 35MW electricity to the American Israel Paper Mills through a local connection, while the rest of the electricity will be sold to other private users or the Israel Electric Company via the national grid. When electricity is sold to private users, the power plant pays the Israel Electric Company a fee for the use of the national grid. Integrated Energy estimates that the power plant will have a net capacity of 205 MW.

The project will claim emission reductions from the electricity generation fuelled by natural gas instead of the baseline electricity generation from the coal-dominated national grid. The project's technology generates electricity more cleanly and efficiently than the majority of electricity generation in the Host Country. As mentioned above, the majority of electricity in the Host Country is generated by coal-fired power plants, which produce more greenhouse gas emissions than natural gas power plants. Furthermore, the project uses combined-cycle technology, which generates electricity at a very high efficiency, ensuring that tCO_2/kWh will be lower than a conventional power plant. Many of the power plants operating in the Host Country use single-cycle technology and must use a higher proportion of fuel for each kW generated than combined-cycle. Therefore, the Integrated Energy power plant will provide the Host Country with a new source of cleaner electricity with lower greenhouse gas emissions.

The emission reductions for the project activity will be calculated solely from the electricity generation component that will displace electricity generated by the coal-dominated Israeli grid. The steam produced in the power plant is produced from waste heat and no emission reductions will be claimed for the waste-heat generated steam. Emissions reductions will only be claimed for the electricity component of the power plant, ensuring that the emission reductions claimed for the project will be highly conservative.

A.2.2 Contribution to Sustainable Development

Israel's government is committed to the principles of sustainable development and to the implementation of a national sustainable development strategy. The project activity meets the sustainable development criteria established by Israel's Designated National Authority. The project activity contributes to the following sustainability objectives:

Environmental

- The project will address climate change by reducing the amount of greenhouse gases (GHG) emissions generated from electricity production.
- The project will produce fewer air pollutants, such as NOx, SOx and particulate matter than electricity generation from existing sources in the Host Country.

Social

- The new power plant is located outside of Israel's economic centre where the majority of employment is situated. The project will provide a number of job opportunities during its construction and operational lifetime.

Economic

- The power plant's construction will not only provide employment but also use goods and services in the Host Country, thus supplying further economic opportunities to local businesses, such as food providers and cleaning companies.
- The project activity is one part of the government's ongoing policy of economic liberalization and privatization.
- Electricity is necessary for development in the Host Country. The diminishing electricity reserve is worrisome and would force the government to approve the construction of an additional coal-fired power plant in order to meet the domestic and industrial demand for electricity. One such coal fired plant (Project D) has already been approved and another (Project E) is being planned. The successful construction of private natural gas plants has the potential to annul or at least delay these decisions.

A.3. Project participants:

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Name of Party involved (*). ((host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicates if the Party involved wishes to be considered as project participant (Yes/No)
Israel (Host)	Integrated Energy Ltd. Private entity. Project Developer.	No
	EcoTraders Ltd. Private entity. CDM project manager and consultant	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Israel

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

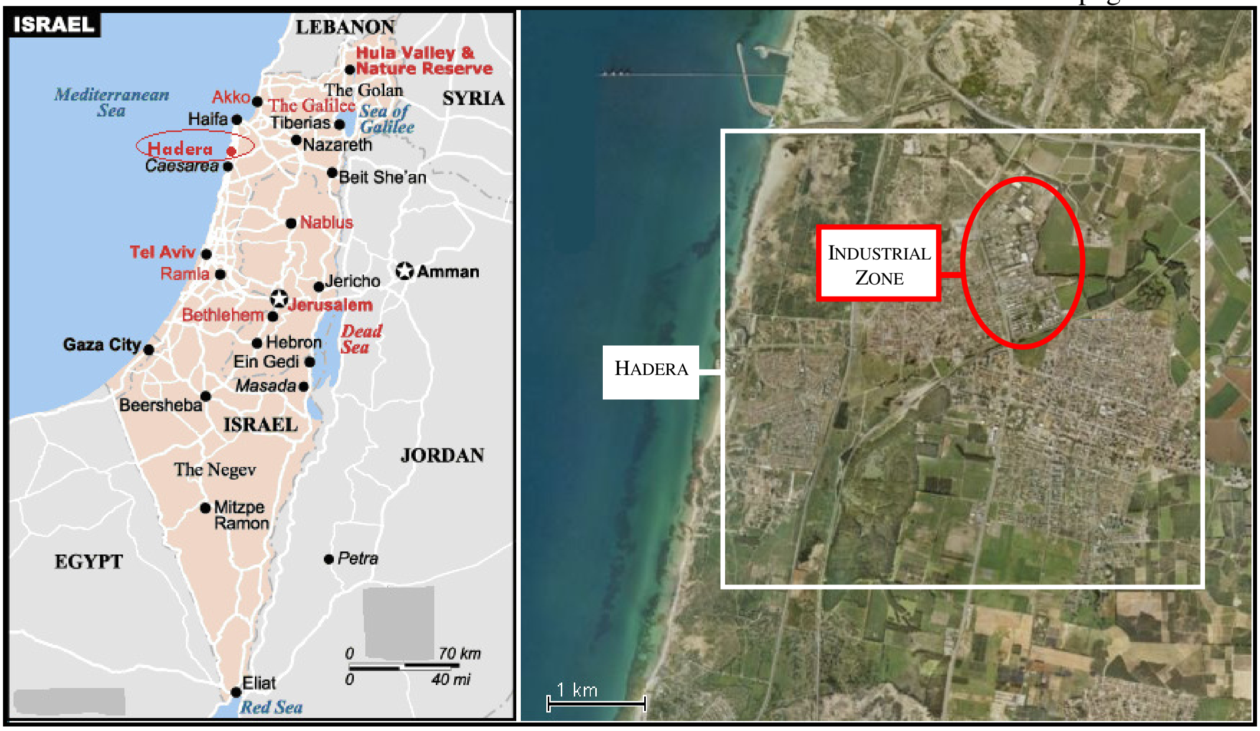
Haifa Region

A.4.1.3. City/Town/Community etc:

Hadera

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

The Integrated Energy power plant is located in the Hadera industrial zone.



The Integrated Energy office is located at Meizer St, the Hadera Industrial Zone, P.O. Box 142, 38101. The co-ordinates of the project are 32°27'10 N and 35°54'55 E.

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

The project activity is a large scale project, which falls into category 1: Energy industries (renewable/non-renewable), as contained in the list of Sectoral Scopes.

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

Technical Description

The power plant will be a dual-fuel combined cycle co-generation natural gas power plant with one gas turbine, with a nominal power of 150 MW; one Heat Recovery Steam Generator (HRSH) with three pressure levels, post firing system, fresh air system and integrated de-aerator; and one single entry, no reheat Steam Turbine (ST) with a nominal power of 70 MW with two steam extractions. The plant's thermal efficiency is expected to be 68%.

Environmental and Safety Standards

The equipment used in the project will meet international standards for environmental quality and safety.

Noise

ISO standards will be used to determine the noise levels inside and outside of the power station.

Water Quality

Effluents will be treated according to international standards to protect water quality.

Fire Safety

A fire fighting system will be designed and constructed in compliance with Israeli national codes and requirements of the local fire council

Technology Transfer
The power plant will be constructed and will operate in a non-Annex I country. Technical equipment will be procured from one or more Annex I country companies. An Annex I company will be required during the plant's construction and during its commissioning. The Annex I company will be involved in aspects of training and operation for the new power plant.

A.4.4 Estimated amount of emission reductions over the chosen crediting period:

Year	Annual estimation of emission reductions in tones of CO2e
2011	578,243
2012	578,243
2013	578,243
2014	578,243
2015	578,243
2016	578,243
2017	578,243
2018	578,243
2019	578,243
2020	578,243
Total estimated reductions	5,782,430
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tCO2e)	578,243

A.4.5. Public funding of the project activity:
There is no public funding from an Annex I Party to the UNFCCC available for the project activity.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:
The approved baseline and monitoring methodology used for the project activity is Approved baseline methodology AM0029 (Version 1.1), “Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas”.[4]

This methodology makes use of ACM0002 "Consolidated methodology for grid-connected electricity generation from renewable sources" (Version 6) to calculate the grid emissions factor. The methodology

[4] AM0029, Version 1.1 is valid for projects that request registration prior to July 1, 2008.

also requires the use of the most recent version of "The tool for the demonstration and assessment of additionality" (Version 04).

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

The methodology AM0029, version 01.1 states that the baseline methodology is applicable to the following projects:

Applicability Clause	Applicability of the clause to the small scale project activity
"The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. . (Natural gas should be the primary fuel. Small amounts of other startup or auxiliary fuels should be used, but can comprise no more than 1% of total fuel use.)"	✓ The power plant in the project scenario is a new power plant that will be connected to the national grid and can operate on natural gas or diesel (dual-fueled). The power plant's license does not permit the use of a fuel other than natural gas except when ordered to do so by the government in the case of national emergencies. All NG power plants of over a 100 MW capacity are required by the Israeli law to be duel fueled for emergency purposes. If such an emergency arises and a fuel other than natural gas is used, no emission reductions will be claimed. In the project only natural gas will be used and no other fuel will be used for auxiliary purposes.
"The geographical/ physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available."	✓ The geographical/ physical boundaries of the baseline grid can be clearly identified as the national public grid of Israel. The grid in Israel is not interconnected and there are no power imports (see Annex 3). Grid information for calculating baseline emissions is publicly available on demand from the Israel Electric Company (IEC).[5]
"Natural gas is sufficiently available in the region or countries, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity."	✓ Natural gas availability in the region is sufficient that the project activity will not limit the natural gas supply to other users. The project's consumption of natural gas does not displace natural gas from other consumers because there is sufficient natural gas supply in the region, which is defined as the Middle East.[6] In 2001, total natural gas reserves in the Middle East were estimated at 17,625 BCM. The estimated natural gas reserves

[5] http://www.israel-electric.co.il/bin/en.jsp?enDispWhat=Zone&enZone=Contact&enDispWho=Contact&enPage=WidePage&enDisplay=view&

[6] The Middle East region includes Iran, Saudi Arabia, Iraq, Egypt, Syria, Israel and the Palestinian Authority.

	available in Israel is 50 BCM and in Egypt, 1,204 BCM.[7] In the Middle East, Israel can purchase natural gas from Egypt and other countries can purchase natural gas from each other. Industry in Israel is operating under the assumption that the gas availability in Egypt is such that it will not limit the development of natural use in Israel or limit economic development in Egypt. According to the Israeli Energy Sector Master Plan, developed by the Ministry of Infrastructure and shown to the DOE, the projection is that by 2025 the expected demand in Israel for natural gas will be 19,032,000 metric tones, or 26,551,339,286 cubic meters (density of methane is 0.0007168 [Ton/m3]), which is 26.5 BCM. Israeli demand at a level of 26.5 BCM will consume 2.2% of the Egyptian natural gas reserves and 0.15% of the natural gas reserves in the Middle East region, thus proving that the natural gas reserves in the region are sufficient to supply the entire Israeli demand even 20 year from now, according to the governments forecast.[8] According to the Israeli Energy Sector Master Plan, the projection is that on average, demand for natural gas in Israel will increase at a rate of 33% per year between the years 2001 – 2025, thus showing an energy market that is not operating under any supply limitations. Therefore, there are no price-inelastic supply constraints.

B.3. Description of the sources and gases included in the project boundary

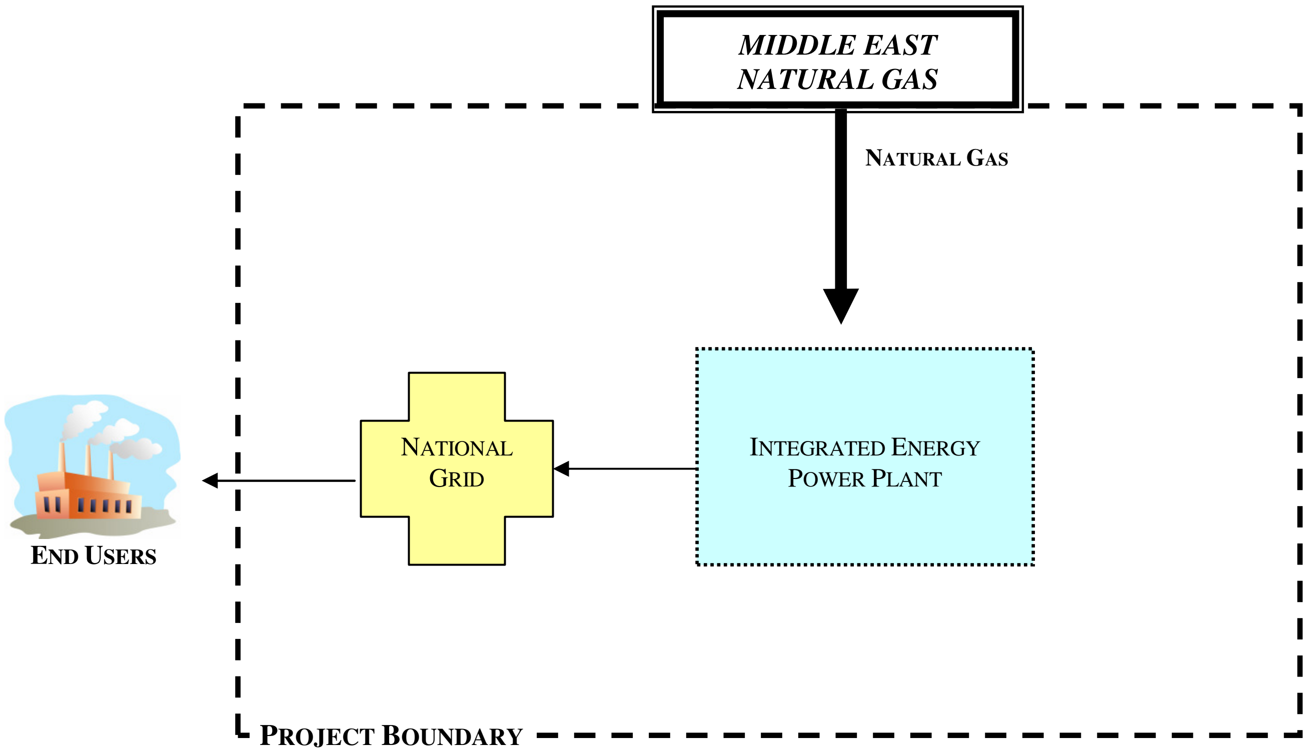
Below are the GHGs included in or excluded from the project boundary, as specified by Methodology AM0029:

	Source	Gas	Included?	Justification/Explanation
Baseline	Power generation in baseline	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification by AM0029. This is conservative.
		N_2O	No	Excluded for simplification by AM0029. This is conservative.
Project	On-site fuel	CO_2	Yes	Main emission source.

[7] National Ministry of Infrastructure. Gas Reserves in the Mediterranean, 2001. http://www.mni.gov.il/mni/he-il/Energy/NaturalGas/NGGeneralData/NGMiddleEastReserves.htm. Available only in Hebrew.

[8] "Energy Demand Projections, 2001-2025". National Ministry of Infrastructure, p.4. Accessed November 27, 2007. Translation provided to the DOE.

Activity	combustion due to the project activity	CH_4	No	Excluded for simplification by AM0029.
		N_2O	No	Excluded for simplification by AM0029.



AM0029 defines the project boundary as "the project site and all power plants connected physically to the baseline grid as defined in ACM0002 version 06." The baseline grid is the national grid of Israel. Therefore, the project includes the project activity power plant and the national grid of Israel.

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

The methodology AM0029 sets out the following steps to determine the baseline scenario.

1. Identify plausible baseline scenarios,
These should include scenarios which provide realistic and credible alternatives that provide outputs or services comparable to the proposed CDM project activity.

Sub-steps 1a. Alternatives to the project

<table>
<tr><th>Alternative Baseline Scenario</th><th>Delivers similar outputs and services to the project activity?</th><th>Consistent with mandatory applicable laws and regulations?</th><th>Plausible Baseline Scenario?</th></tr>
<tr><td colspan="4"><u>The project activity not implemented as a CDM project</u></td></tr>
<tr><td><u>a) Project activity without CDM</u>
Natural gas co-generation power plant of 205MW: Includes 1 gas turbine, 1 heat recovery steam generator and 1 steam turbine
Electrical Efficiency: 44%
Thermal Efficiency[9]: 65%
Technical lifetime: 20 years</td><td>Yes.</td><td>Yes.</td><td><u>Plausible baseline scenario.</u></td></tr>
<tr><td colspan="4">Power generation using natural gas, but technologies other than the project activity</td></tr>
<tr><td><u>b) Power generation using a natural gas turbine without waste heat recovery, 205MW</u> single cycle system, which includes gas turbines that produce electricity, but does not have a heat recovery steam generator and steam turbine.
Electrical Efficiency: 38.2%
Technical lifetime: 20 years</td><td>No.</td><td>Yes.</td><td>This is not a viable option, as it does not produce the same output or provide the same service as the project activity. First, it produces only electricity, while the project activity produces both electricity and steam. Second, this type of power plant would be used to generate peak-load electricity, while the project activity is a base-load power plant. In addition, a natural gas turbine without waste heat recovery is far less efficient than the project activity, making it less economical and more polluting.</td></tr>
<tr><td><u>c) Power generation using natural gas engines with co-generation. A 202.5MW</u> system that includes gas engines to produce electricity, and a heat recovery steam generator to produce steam from the waste heat.
Electrical Efficiency: 44%
Thermal Efficiency: 66%</td><td>Yes.</td><td>Yes.</td><td>Not a plausible scenario due to a common practice barrier. An individual gas engine has the capacity to generate only 5.5 MW. In order to have the capacity to generate as much electricity as the project activity, the power plant would have to include 37 gas engines, making it an extremely complicated system. It</td></tr>
</table>

[9] Thermal Efficiency is defined as the output of the plant (both electrical and thermal (steam)) divided by the input of the plant (fuel input in energy units).

Technical lifetime: 20 years			therefore is not common industry practice to generate electricity on this scale using gas engines.
d) Power generation using a natural gas fired boiler and a steam turbine, 212MW Electrical Efficiency: 33% Thermal Efficiency: 49% Technical lifetime: 20 years	No.	Yes.	Power generation using a natural gas fired boiler and a steam turbine is not a viable option, as it does not provide the same output. This technology generates far more steam relative to electricity, and therefore is best suited for co-generation where steam, not electricity, is the primary output. Should this technology be employed in a manner that meets the project's production needs, it would have the lowest efficiency of all natural gas co-generation alternatives, making it the least economical and the most polluting.
Power generation technologies with fuels other than natural gas			
e) Power generation technologies with fuels other than natural gas Conventional steam driven coal co-generation power plant, 350 MW Electrical Efficiency: 35%; [10] With the paper mill's consumption of steam, the thermal efficiency will reach 45.12% Technical lifetime: 20 years	Yes.	Yes.	Plausible baseline scenario. The IEC has planned a new coal-fired power plant in Ashkelon, which was approved by the government in 2003.[11] The Ministry of National Infrastructure sees the new coal-fired plant(s) as crucial to meet future energy demand in the Host Country.[12]
Power generation technologies using energy sources other than natural gas			
f) Power generation technologies with fuels other	Yes.	Yes.	Not plausible scenarios due to common practice barrier. The

[10] Department of Energy. Fact Sheet: Clean Coal Technology Ushers In New Era in Energy. http://www.state.gov/g/oes/rls/or/2006/77196.htm. Accessed July 15, 2007.

[11] "The Construction of a New Coal-Fired Power Plant in Ashkelon to be Accelerated". Ynet News Service. http://www.ynet.co.il/articles/0,7340,L-3340910,00.html. Accessed July 15, 2007. Available in Hebrew only.

[12] Speech given by Minister Ben Eliezer at the Energy Conference, May 2007. http://www.mni.gov.il/mni/he-il/Energy/Messages/SpokesmanEnergyConference.htm. Accessed July 15, 2007. Available in Hebrew only.

than natural gas Heavy fuel oil (HFO)-fired power plant, 205MW Electrical Efficiency: 35%[13] Technical lifetime: 20 years			most recently constructed power plant that operates primarily on HFO was constructed in 1977. Furthermore, between 1995 and 2005 the consumption of HFO for electricity generation in the Host Country fell 74%, from 32.7% of total fuel consumed to 8.5% of the total. (Please see page 19 of the PDD.)[14] HFO clearly is declining in use for electricity generation in the Host Country.
g) Power generation technologies with fuels other than natural gas Diesel-fired co-generation combined cycle power plant, 205MW Electrical Efficiency: 44% Thermal Efficiency: 65% Technical lifetime: 20 years	Yes.	Yes.	Plausible baseline scenario.
h) Power generation technologies with fuels other than natural gas Renewable energy: solar and wind, 205MW	Neither solar nor wind power can deliver the high quantities of electricity, nor can guarantee consistent delivery of services. Wind power is not a feasible source of energy at the location of the project activity. Solar energy would require a much larger area than the project's area to produce 205 MW and cannot provide energy at night. In addition, neither of these technologies can supply base-load electricity or provide waste heat.	Yes.	Not a plausible baseline scenario due to technological and common practice barriers in the Host Country. Renewable energy cannot provide similar services and output as the project activity because wind resources are not sufficient and there is a lack of available space in the Host Country for solar energy on a large scale. In 2007 it was reported in a study presented to the Israeli Government (Committee for Science and Technology), that of the 48,379 million kWh generated in the Host Country only 45.5 million kWh, or 0.09% of the total was generated using renewable energy. Wind power contributes 6.2MW to the grid and solar photovoltaic generates 1.5 million

[13] HFO simple cycle efficiency - http://www.projectsources.com/html/DG.htm - Please see description of "CTs (Combustion Turbines)".

[14] Israel Electric Company's Statistical Report, 2005. http://www.iec.co.il/Static/WorkFolder/IRR/Statistic%20Report%202005.pdf.

			kWh (0.003% of total electricity generation).[15] It is not common practice in the Host Country to generate electricity from renewable sources and there is no production of renewable electricity on the scale of 205 MW in the Host Country.
Import of electricity from connected grids, including the possibility of new interconnections			
i) Import of electricity from connected grids, including possibility of new interconnections Import of electricity	No. The Israeli grid is similar to that of an island. There are no connections with the electricity grids of neighbouring countries. For political and security reasons, no new interconnections are possible.	Not applicable. No connection to other electricity grids.	Not a plausible baseline scenario due to institutional barriers. The Israeli grid resembles that of an island and is not connected to any other grid for political and security reasons. Importing electricity is more sensitive strategically than importing natural gas, which is simply a fuel source. The country must be self-sufficient for electricity generation, but it can replace natural gas as a fuel in the case of a national emergency or buy NG from a different supplier.

The analysis provided in the chart above presents the following options as plausible alternatives for the baseline scenario:

a) The project activity not implemented as a CDM project (natural gas)
e) Coal-fired power plant
g) Diesel-fired power plant.

Step 2. Identify the economically most attractive baseline scenario alternative.
According to Methodology AM0029, the most attractive baseline scenario shall be identified using investment analysis. The most suitable financial indicator for comparison between different project options is project IRR and levelized costs. For this reason, the project's IRR and the levelized cost of electricity production in $/kWh will be used as financial indicators for investment analysis to determine the baseline scenario. These financial indicators for the possible baseline scenarios (a), (e) and (g) are shown below.

A sensitivity analysis will be performed and the most economically attractive alternative will be selected as the most plausible baseline scenario. All the parameters for each scenario are available in the models that have been submitted to and reviewed by the DOE.

[15] Yaniv Ronen "Electricity Generation from Alternative Fuels in Israel". Presented to the Israeli government, Committee for Science and Technology, January 15, 2007. www.knesset.gov.il/mmm/data/docs/m01650.doc. Available in Hebrew. Translation provided to DOE. Accessed on December 6, 2007.

Assumption used in models	Natural Gas Power Plant[16]	Coal-fired Power Plant[17]	Diesel Power Plant[18]
Project period	20 years	20 years	20 years
Heat Rate	7,742 Btu/kWh	9,500 Btu/kWh	7,742 Btu/kWh
Fuel price	(4.72 US$/MBTU including transportation costs and taxes)	2.13 US$/MBTU	1,110 US$/tonne
Net electricity available for sale	205 MW	333 MW	205 MW
Depreciation	3 years	3 years	3 years
Levilized cost	**US$ 41.36/MWh**	**US$ 34.06/MWh**	**US$ 133.32/MWh**
IRR	**6.4%**	**10.55%**	Cannot be calculated (large negative)

According to the natural gas contract, the price per MBTU remains constant for the first 8 years. In years 9 to 15 of the contract, the price per MBTU increases by 20% each year. The contract is for 15 years only, so an assumption was made that for years 16 to 20 the price per MBTU will increase by 30% from the base price (year 1).

The model assumes that price of coal increases by 2 percent each year. By the twentieth year of the plant's operation the price of coal will have increased by 49%.

The project activity is a dual-fuel power plant, which means that it can operate on natural gas or diesel. As explained above, the plant's business license does not permit the use of a fuel other than natural gas except in the case of a national emergency when the government will instruct it to use diesel. This means that the configuration of the diesel power plant is the same as the natural gas power plant and the financial model reflects this. Assuming the same technical parameters for diesel as for NG (ex. Heat rate) is extremely conservative as NG is more efficient than any liquid fuel.

The price of diesel in the model increases each year by 2 percent. The price of diesel is such that the model could not return an IRR for the diesel scenario, although it did provide a levelized cost that is much higher than for the natural gas and coal options.

The project activity without CDM (natural gas power plant) and a diesel power plant have higher levelized costs and lower IRRs than does the coal power plant. A sensitivity analysis was performed to confirm which scenario would be selected for the baseline scenario.

[16] Price proposal for the power plant.

[17] Environmental Protection Agency and U.S. Department of Energy. *Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*. Published July 2006.

[18] The power plant in the project is dual-fuel, meaning that it can be operated on either natural gas or diesel. The configuration for the diesel plant is the same, therefore, as for the natural gas plant. In addition, oil prices are regulated by the government of Israel (Ministry of National Infrastructure) http://www.mni.gov.il/mni/he-il/Energy/Fuel/FuelPrices/Default.htm

Sensitivity Analysis

A sensitivity analysis was conducted to confirm which of the baseline scenario alternatives would be selected as the baseline scenario. The sensitivity analysis addressed two parameters that are likely to be subject to variability:

- Fuel price (input) – may increase or decrease
- Electricity price (revenue) – may increase or decrease

These indicators were subjected to a 5% increase or decrease in each of the plausible baseline scenarios. A fluctuation of 5% is conservative in a sensitivity analysis where fuel and electricity prices are the variables tested. When the price of fuel, an input in electricity generation, increases, the price of electricity will rise as well. Therefore, it can be understood that if the fuel price increases by 5%, the price of electricity will increase, too, essentially minimising the impact of the fuel price increase as revenue from the sale of electricity increases. Likewise, if the price of fuel falls, the price of electricity may remain the same, or may fall. In either case, the impact of one variable will likely influence the other and minimise the variable's fluctuation. Showing a variation in one variable only is not very realistic, since the variables influence each other, but more clearly shows the impact of the increase or decrease on the model. Therefore, a fluctuation of +/- 5% is conservative. . It should also be noted that as the IEC has been for many years a monopoly in electricity production, electricity prices in Israel are regulated by the government (PUA – Public Utilities Authority) which take fuel prices in to consideration as an input to the price equation and are not decided by each producer. Further more, this sensitivity analysis is very conservative given that, as has been explained before, the financial models already have an increase in fuel prices built in.

To further prove this point, actual data from the Israeli Electric Company's website is shown in Annex 3 of the PDD. The data provided shows all segments which constitute the electricity tariff in Israel and it can be seen that fuel costs make up 51.3% of the electricity tariff.[19]

	Natural Gas Power Plant		Coal Power Plant		Diesel Power Plant	
	IRR (%)	Levelized Cost (US$/MWh)	IRR (%)	Levelized Cost (US$/MWh)	IRR (%)	Levelized Cost (US$/MWh)
Fuel Price +5%	5.14	42.27	9.86	34.55	Cannot be calculated (large negative)	138.88
Fuel Price -5%	7.63	40.44	11.23	33.57	Cannot be calculated (large negative	127.77
Electricity Price +5%	8.3	41.4	11.71	34.11	Cannot be calculated (large	133.37

[19] http://www.israel-electric.co.il/bin/ibp.jsp?ibpDispWhat=zone&ibpDisplay=view&ibpPage=IRRWPage&ibpDispWho=IRRTariff&ibpZone=IRRTariff&

					negative	
Electricity Price -5%	4.52	41.31	9.28	34.01	Cannot be calculated (large negative	133.28

The sensitivity analysis confirms that the project activity not implemented as a CDM project has lower financial indicators than the second plausible option, a coal-fired power plant, even in circumstances where costs and revenues vary. Even the highest IRR (8.3%) and lowest $/MWh ($40.44) scenario shown for the natural gas project is not as attractive as the lowest IRR (9.28%) and highest $/MWh ($34.55) scenario shown for the coal power plant. The diesel plant option is not a feasible financial option, with fuel costs that are so high that no IRR can be calculated and a levelized cost that is much higher than the other options. The conclusion is that option (c), the coal-fired power plant, is clearly the most financially attractive alternative. Therefore, the coal-fired power plant is selected as the baseline scenario, according the requirements laid out in AM0029 for selecting the baseline scenario.

B.5. 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 (assessment and demonstration of additionality):

The methodology AM0029, version 1.1 requires the following steps to determine the additionality of the CDM project activity. Each step refers to the requirements specified in the most recent version of the "Tool for demonstration and assessment of additionality". The most recent version of the Tool is Version 04 issued by the Executive Board at its 36th meeting.

Step 1: Benchmark investment analysis

Benchmark analysis requires demonstrating that the proposed CDM project activity is not likely to be financially attractive by applying sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the latest version, of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board (version 04).

Financial analysis

The project developer conducted a financial analysis to determine the project's equity IRR for the benchmark investment analysis. Equity IRR has been selected for the project's benchmark because it is the most accurate measure of how a financial decision is made when assessing the viability of a potential project. A project developer makes his decision about a project's profitability and viability based on the return he will receive on his investment. At its 36th meeting the EB decided that equity IRR can be used as a financial indicator to show the project developer's dilemma when investing in a new project. Therefore, equity IRR was chosen to provide an accurate benchmark for the project's financial analysis.

The following assumptions were made in calculating the CDM project's equity IRR:

- The plant's available electricity for sale is 205 MW during peak and shoulders time and 120 MW during off peak time;
- The debt to equity ratio is 65:35;
- The plant's maximum operational availability is 97.3%;

- During peak hours, the plant will operate at full capacity and during off-peak hours, it will operate at 60% capacity;
- The cost of natural gas is US$4.72/MBTU;
- There are different revenues from the sale of electricity, depending on whether the electricity is sold to private users or to the Israel Electric Company (IEC); Private customers purchase from Integrated Energy at a discount price from IEC's tariffs.
- There is a backup contract that allows Integrated Energy to sell to the IEC if it wishes and that the IEC must purchase a great part of the electricity.
- Electricity will be sold to private customers on average at a five percent discount on the price offered by the IEC:

	161 KV			
	winter	spring	summer	autumn
Peak tariff (cents)	11.87	9.84	11.96	9.84
Shoulder tariff (cents)	6.83	5.87	7.59	5.87
Off-peak tariff (cents)	1.91	2.00	2.08	2.00

According to industry statistics for electric utilities, power station development is considered viable with equity IRR of 11.7%.[20]The "Tool for demonstration and assessment of additionality" requests in sub-step 2b (Benchmark analysis) that the benchmark chosen "… represent standard returns in the market, considering the specific risk of the project type, not linked to the subjective profitability". For this reason, the benchmark chosen is the actual equity IRR of the top 75 electric utility companies in the United States as summarized in the industry browser provided. It is not a subjective estimate but rather a specific actual index which best represents the returns in this specific market.

In order to insure that this value is in fact conservative and represents the associated risk in the specific country, it is compared to the first option given in sub-step 2b of the additionality tool "government bond rates increased by a suitable risk premium." Financial data was taken from the official site of the Tel Aviv stock exchange. Two financial indices where examined:

1. Government bond indices[21] (60%) - General Index which includes all the government bonds traded on the exchange.
2. Tel Aviv 100 indices[22] (40%) - The TA-100 Index is one of the TASE's (Tel Aviv Stock Exchange) leading indices, published from 1992. The index consists of the 100 stocks with the highest market capitalization that are included in the TA-25 and TA-75 indices.

[20] Industry Statistics for Electric Utilities. Yahoo Finance, Industry Center. http://biz.yahoo.com/ic/911.html. Accessed December 6, 2007.

[21] http://www.tase.co.il/TASEEng/MarketData/Indices/Bond/Government/IndexMainDataBonds.htm?Action=1&IndexID=602

[22] http://www.tase.co.il/TASEEng/MarketData/Indices/MarketCap/IndexMainDataMarket.htm?Action=2&IndexID=137

A three year average of the returns from these two indices was calculated for the years 2004 - 2006. These years represent the years prior to the decision making stage of the project. To account for the medium risk project at hand the two indices where averaged on a 60/40 basis. The construction and operation of Integrated Energy PP is considered a medium risk project. The risk is lowered due to the backup power purchase agreement set by the regulator with IEC, yet the project is vulnerable to other risks such as those associated with the immature NG market at the time of initiation. The results of the calculations are:

Government Bonds:

Annual Yield 2004	Annual Yield 2005	Annual Yield 2006	Average
5.4%	5.9%	5.4%	5.6%

TA 100:

Annual Yield 2004	Annual Yield 2005	Annual Yield 2006	Average
19.0%	29.8%	13.2%	20.68%

Weighted Average
11.61%

This result which is very close the value of the benchmark chosen, proves that the benchmark chosen does represent the standard returns in the market as seen by the project developer. Additional information regarding the indices can be found in Annex 3.

The project activity without CDM revenues results in an equity IRR of 6.28%, which is lower than the benchmark. With CDM revenue from the sale of CERs throughout the project's crediting period, the project's equity IRR increases to 19.27%, which shows the importance of CDM revenue to the project's viability. The sensitivity analysis will also demonstrate that without the CDM the project is not financially attractive. All financial data used to arrive at the internal rate of return for the project activity will be provided to the DOE during the validation process.

Sensitivity Analysis

The equity IRR for the project (without CDM revenues) was checked using a sensitivity analysis for the following factors:

1. Change in the price of natural gas: +/- 5%
2. Change in the price of electricity: +/-5%

The prices of natural gas and electricity were chosen as possible fluctuating factors for the sensitivity analysis because these are factors that are most likely to vary over the course of time. The price of natural gas may change according to fluctuations in the global fuel market, while the price of electricity fluctuates according to the cost of fuel and supply and demand. Electricity prices are set by the Electricity Authority (PUA), a regulated public body, which sets the prices according to the cost of electricity generation. There is a strong correlation between the cost of fuel and electricity prices and when the price of fuel increases, electricity prices also rise.

These indicators were subjected to a 5% increase or decrease. A fluctuation of 5% is conservative in a sensitivity analysis where the natural gas and electricity prices are the variables tested. When the NG price, an input in electricity generation, increases, the price of electricity will rise as well. Therefore, it can be understood that if the NG increases by 5%, the price of electricity will increase, too, essentially minimising the impact of the NG increase as revenue from the sale of electricity increases. Likewise, if the price of NG drops, the price of electricity may remain the same, or may fall. In either case, the impact of one variable will likely influence the other and minimise the variable's fluctuation. Showing a variation in one variable only is not very realistic, since the variables influence each other, but more clearly shows the impact of the increase or decrease on the model. Therefore, a fluctuation of +/- 5% is conservative. It should also be noted that as the IEC has been for many years a monopoly in electricity production, electricity prices in Israel are regulated by the government (PUA – Public Utilities Authority) which take fuel prices in to consideration as an input to the price equation and are not decided by each producer. Further more, this sensitivity analysis is very conservative given that, as has been explained before, the financial model already has an increase in NG prices built in.

To further prove this point, actual data from the Israeli Electric Company's website is shown in Annex 3 of the PDD. The data provided shows all segments which constitute the electricity tariff in Israel and it can be seen that fuel costs make up 51.3% of the electricity tariff.[23]

Load factor was not chosen for the sensitivity analysis because it is not expected to vary; the IPP Delek Ashkelon power plant has a backup contract with the Israel Electric Company (IEC) that requires the IEC to purchase the majority of electricity produced at the plant.

When the values of these factors were changed to check the project's equity IRR under different possible scenarios that could develop, it was found that the project's financial attractiveness was still below the project benchmark identified above (equity IRR of 11.7%) without CDM revenue, but that the project exceeds the benchmark when CDM revenue is taken into account.

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[23] http://www.israel-electric.co.il/bin/ibp.jsp?ibpDispWhat=zone&ibpDisplay=view&ibpPage=IRRWPage&ibpDispWho=IRRTariff&ibpZone=IRRTariff&

Scenario	Parameter	Variation	Equity IRR
1	Natural Gas Price	+5%	2.01%
		-5%	9.63%
2	Electricity Price	+5%	11.15%
		-5%	-0.78%

The sensitivity analysis conducted above clearly indicates that the project activity without CDM revenues is not financial viable.

Step 2. Common Practice Analysis

The Common Practice Analysis procedure set forth in the "Tool for the demonstration and assessment of additionality" version 04 requires the identification and discussion of other activities implemented previously or currently underway that are similar to proposed CDM project activity.

Electricity in Israel is generated from coal, heavy fuel oil, diesel and natural gas.

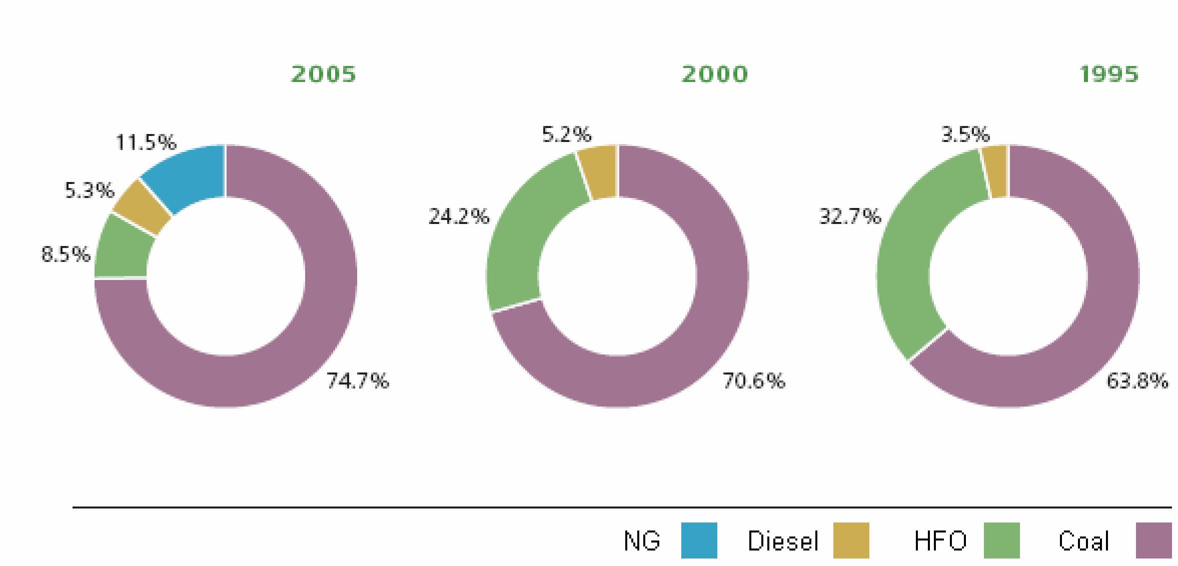

Figure 1: Fuels used for Electricity Generation in Israel (Israel Electric Company's Statistical Report, 2005)[24]

[24] Available in Hebrew at http://www.israel-electric.co.il/Static/WorkFolder/Investors/Statistic%20Report%202005.pdf.

Coal accounts for three-quarters of electricity generation in Israel. Natural gas forms a small percentage of total electricity generation. Coal is clearly the dominant fuel for electricity generation and its use increased by 17% between 1995 and 2005. It is clear that activities similar to the project activity, i.e. power generation using natural gas, is not common practice.

Since the mid-1980s, the Israeli government has wished to introduce natural gas to the industrial sector. In 1995, the government established the Natural Gas Authority to promote the development of natural gas infrastructure in Israel. The national plan for the installation of a natural gas pipeline (National Plan 37) was completed in 1999. The plan was to be implemented immediately upon its finalization, although actual implementation encountered unforeseen obstacles. The government published a tender with the intention that a single private body will construct, maintain and operate the pipeline. After the tender failed in 2003, the government realized that only a governmental body could undertake a project of this magnitude. Israel Natural Gas Lines Ltd (INGL) was established to construct the natural gas pipeline and received a license to do so in 2004.

Construction of the pipeline began in 2004.[25] The INGL project was delayed for a number of reasons. No natural gas transportation system had ever been constructed in Israel, which meant that there was a lack of skilled and properly trained personnel to implement the project. Construction was delayed as well because it was difficult for the INGL to acquire the necessary building permits to construct the pipeline because local authorities, such as the Fire Authority and municipalities, were sensitive to the risks posed by a natural gas pipeline and were not comfortable issuing building permits when they could not fully predict the risk the gas pipeline posed..

As of December 2007, over three years since the construction of the natural gas delivery system began, the natural gas delivery system in the Host Country is not completed and infrastructure is still lacking to make all of the completed sections operational. Only a minor part of the natural gas pipeline as planned has been installed, delaying further the arrival of natural gas to Israel. The lack of a natural gas infrastructure means that natural gas is not widely used for energy generation in the Host Country. It can be concluded that electricity generation using natural gas for the fuel source cannot be considered common practice in the Host Country because the lack of natural gas infrastructure to supply natural gas has impeded its introduction in the Host Country.

Step 3. Impact of CDM Registration
Version 04 of the "Tool for the demonstration and assessment of additionality" does not contain directions to determine the impact of CDM registration on the project. Therefore, for this step Version 02 of the Tool will be used.

The financial and common practice barriers elaborated above posed barriers to the actualization of the project. In the absence of the project activity, the electricity would have been generated by a new coal-fired power plant, which would have led to higher CO_2 emissions. However, revenue from the sale of certified emission reductions, which is only possible through the CDM process, raises the project's equity IRR to 19.27%. CDM revenue brings up the project's equity IRR to beyond that of the benchmark equity IRR of 11.7%, showing that CDM revenues increase the probability that the Integrated Energy natural gas power plant will accept the financial risk that the project activity poses.

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[25] Survey of the Natural Gas Sector in Israel. Conducted by Ma'a lot (the Israeli Company for Ranking Bonds). Accessed July 10, 2007. http://www.maalot.co.il/content.asp?PageId=229.

The project will improve environmental quality in the Host Country by bringing online a new source for electricity that will have lower GHG, NOx, SOx and particulate matter emissions than most of the other power plants that supply the national grid. However, because there are few private natural gas power plants existing or being planned to supply the grid in Israel, the project activity's success will be closely monitored by other companies that are considering entering the electricity sector using natural gas. Should more natural gas power plants be constructed, Israel will gain a cleaner electricity supply. The project's risk, due to the novelty of natural gas in the Host Country and its low financial returns, will be mitigated by the support from the CDM revenue.

The Integrated Energy Natural Gas Power Plant project is additional because it meets the criteria for additionality in each of the above steps, according to the requirements set out in the most recent version of the "Tool for the demonstration and assessment of additionality".

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Project Emissions:
Equations provided by methodology AM0029 are used to calculate project emissions, baseline emissions, leakage and emission reductions.

The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \qquad (1)$$

Where:

$FC_{f,y}$	The total volume of natural gas in year(s) ‘y’	m^3
$COEF_{f,y}$	The CO_2 emission coefficient in year(s) 'y' for natural gas	tCO_2/m^3

The CO_2 emissions coefficient is calculated by:

$$\mathbf{COEF_{f,y} = \Sigma NCV_y * EF_{CO2,f,y} * OXID_f} \qquad (2)$$

Where:

$NCV_{f,y}$	The net calorific value (energy content) per volume unit of natural gas in year ‘y’ as determined from the natural gas supplier, wherever possible, otherwise from local or national data.	TJ/m^3
$EF_{CO2,f,y}$	The CO2 emission factor per unit of energy of natural gas in year ‘y’ as determined from the natural gas supplier, wherever possible, otherwise from national or global data;	tCO_2/TJ
$OXID_f$	The oxidation factor of natural gas (IPCC)	--

Baseline emissions
Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \tag{3}$$

Where:

BE_y	Baseline emissions in year y	tCO_2
$EG_{PJ,y}$	Electricity generated in the project plant	MWh
$EF_{BL,CO2,y}$	Baseline CO_2 emission factor of the grid	tCO_2/MWh

The methodology requires that the procedure for calculating $EF_{BL,CO2,y}$ result in the lowest emission factor from these three options:

Option 1: The build margin, calculated according to ACM0002 version 06; and
Option 2: The combined margin, calculated according to ACM0002 version 06, using a 50/50 OM/BM weight.
Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated according to Equation (4) provided in AM0029 version 1.1.

According to methodology AM0029, if either option 1 (BM) or option 2 (CM) is selected, they will be estimated *ex post*, according to the methods described in ACM0002. For the purpose of the calculations for the PDD, the $EF_{BL,CO2}$ is determined *ex ante* using the most recently available data from the Israel Electric Company.

The option to determine $EF_{BL,CO2,y}$ was made at validation based on *ex ante* calculations. Option 2 (the combined margin, CM) was selected to determine of the $EF_{BL,CO2,y}$ because it had the lowest value of the three options provide by AM0029. The calculations for each of the three options are available in Annex 3. Therefore, the following steps were taken to determine baseline emissions for the calculation emission reductions:

The equations from ACM0002 version 06 to calculate the combined margin:

STEP 1. Calculate the Operating Margin emission factor(s) ($EF_{OM,y}$) based on one of the four following methods:

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch Data Analysis OM, or
(d) Average OM.

The Dispatch Data Analysis method should be the first choice and requires the following information:

a. "The grid system dispatch order of operation for each power plant of the system"; and
b. "The amount of power (MWh) that is dispatched from all plants in the system during each hour that the project activity is operating".

Dispatch Data Analysis was not chosen for the calculation of the OM because the required information is not publicly available. The only publicly available information pertaining to the Host Country's national grid is the total yearly amount of electricity produced and the fuels used by each of the grid connected plants (which is the information needed for the simple OM method). According to the Meth Panel's response to clarification request AM_CLA_0037, only if the required information for Dispatch Data Analysis is not available may the Dispatch Data Analysis method not be used. The Israel Electric Company publicly provides data of electricity generation by and fuel consumption of each power plant,

but does not provide the grid system dispatch order of operation for each plant or the amount of power dispatched from each plant. Therefore, the OM could not be calculated using Dispatch Data Analysis.

The Simple OM method (a) was chosen because low-operating cost and must run resources, which typically include hydro, geothermal, wind and nuclear power generation either are not used in the host country (nuclear and geothermal) or contribute negligibly to the grid. As described above in section B.4, 0.09% of the total electricity generation in the Host Country is from renewable sources. Total wind capacity is 6.2MW; total hydro capacity is 5.5 MW; and total solar photovoltaics generate 1.5 million kWh (0.003% of total electricity generation).[26]

For the purpose of the PDD calculations the Simple OM was calculated *ex-ante*, i.e. the full generation-weighted average for the most recent 3 years for which data are available at the time of PDD submission. According to the requirements of AM0029, the OM calculation will be made *ex post* during the project activity.

(a) *Simple OM*. The Simple OM emission factor ($EF_{OM,simple,y}$) is calculated as the generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost and must-run power plants:

$$EF_{OM,y} = \frac{\sum_{i,j} F_{i,j,y} . COEF_{i,j}}{\sum_{j} GEN_{j,y}} \qquad (3a)$$

Where:

$F_{i,j,y}$	the amount of fuel i (in a mass or volume unit) consumed by relevant power sources j in year(s) y,	Mass or volume unit
j	the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants, and including imports to the grid,	
$COEF_{i,j\,y}$	the CO_2 emission coefficient of fuel i, taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y	tCO_2/mass or volume unit of the fuel
$GEN_{j,y}$	the electricity delivered to the grid by source j	MWh/yr

The CO_2 emission coefficient $COEF_i$ is obtained as:

$$COEF_i = NCV_i * EF_{CO2,i} * OXID_i$$

Where:

NCV_i	The net calorific value (energy content) per mass or volume unit of fuel *i*	TJ/t
$OXID_i$	The oxidation factor of the fuel (see page 1.29 in the 1996 Revised IPCC Guidelines for default values	%

[26] Yaniv Ronen "Electricity Generation from Alternative Fuels in Israel". Presented to the Israeli government, Committee for Science and Technology, January 15, 2007. www.knesset.gov.il/mmm/data/docs/m01650.doc. Translation presented to the DOE. Accessed on December 6, 2007.

$EF_{co2,i}$	CO_2 emission factor per unit of energy of the fuel *i*	tCO_2/TJ

STEP 2. Calculate the Build Margin emission factor ($EF_{BM,y}$) as the generation-weighted average emission factor (tCO_2/MWh) of a sample of power plants *m*.

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} \cdot COEF_{i,m}}{\sum_{m} GEN_{m,y}} \qquad (3b)$$

Where:

$F_{i,m,y}$	The amount of fuel i consumed by relevant plant m in year(s) y,	Mass or volume unit
m	The power plant delivering electricity to the grid, not including low-operating cost and must-run power plants, and including imports to the grid,	
$COEF_{i,m\ y}$	The CO2 emission coefficient of fuel i, taking into account the carbon content of the fuels used by relevant plant m and the percent oxidation of the fuel in year(s) y	tCO_2/ unit of the fuel
$GEN_{m,y}$	The electricity delivered to the grid by plant m	MWh/yr

AM0029 requires that if project participants select the lowest emission factor of Options 1-3. If Option 1 (BM) or Option 2 (the CM) is selected the calculations will be made *ex post*. However, for the calculations in the PDD, the BM has been calculated *ex ante* based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. ACM0002 version 06 requests that for the BM calculation, the sample group *m* consists of either the five power plants that have been built most recently or the power plant capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. Project participants should use from these two options that sample group that comprises the larger annual generation. The *ex ante* calculation of the BM shows that 20% of the system generation that has been built most recently is larger than the generation of the five most recently built power plants. Therefore, the 20% of system generation value was used for the BM calculation.

Option 3. Emission factor of the technology and fuel identified as the baseline scenario

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \qquad (3c)$$

Where:

$COEF_{BL}$	The fuel emission coefficient based on national average fuel data if available, otherwise IPCC defaults can be used	tCO_2e/TJ
η_{BL}	Energy efficiency of the technology, as estimated in the baseline scenario analysis above.	

For full calculations of Options 1-3 please see Annex 3 to this document.

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{4}$$

Where:

LE_y	Leakage emissions during the year y	tCO_2e
$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH4 emissions in the year y	tCO_2e
$LE_{LNG,CO2,y}$	Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y	tCO_2e

As it is expected that no LNG will be used in the project activity, this parameter has not been included in the calculations.

<u>Fugitive methane emissions</u>

According to AM0029, for the purpose of estimating fugitive CH_4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH_4 emissions ($EF_{NG,\ upstream,CH4}$) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4} \tag{5}$$

Where:

$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y	tCO_2e
FCy	Quantity of natural gas combusted in the project plant during the year y	m³
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year y	TJ/m³
$EF_{NG,upstream,CH4}$	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system	tCH_4 per TJ fuel supplied to final consumers
$EG_{PJ,y}$	Electricity generation in the project plant during the year	MWh
$EF_{BL,upstream,CH4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity	tCH_4/MWh

GWP_{CH4}	Global warming potential of methane valid for the relevant commitment period	tCO_2e/tCH_4

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) should be calculated in a manner consistent with the baseline emission factor ($EF_{BL,CO2}$) used in equation (3) above. Option 2 was used to calculate $EF_{BL,CO2,y}$ above; therefore, Option 2 was used to calculate $EF_{BL,upstreamcH4}$. The equation for calculating $EF_{BL,upstream,CH4}$ is:

Option 2: Combined Margin:

$$EF_{BL,upstream,CH4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH4}}{\sum_i EG_i} \quad (6)$$

Where:

$EF_{BL,upstream,CH4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity	tCH_4 per MWh
j	Plants included in the build margin	
$FF_{j,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin	Mass or volume unit
$EF_{k,upstream,CH4}$	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type)	tCH_4 per MJ fuel produced
EG_j	Electricity generation in the plant j included in the build margin	MWh/y
i	Plants included in the operating margin	
$FF_{i,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin	Mass or volume unit
EG_i	Electricity generation in the plant i included in the operating margin	MWh/y

The methodology states that when reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is not available, project participants should use the default values provided in the methodology below. Where default values from this table are used, the natural gas emission factors for the location of the project activity should be used. The US/Canada values may be used in cases where it can be shown that the relevant system element (gas production and/or processing/transmission/distribution) is predominantly of recent vintage and built and operated to international standards. The natural gas production, processing and distribution systems in the region where the project activity is located are very new, since natural gas was only recently discovered and the entire infrastructure is new, as well. The system operates on the Dutch standard (NEN 3650 requirements for steel, "pipeline transportation systems" ("Dutch standard"). The DOE will be shown proof that the Israeli Natural Gas Lines operate according to this standard as regulated by the Israeli law. Therefore, the US/Canada values will be applied in the leakage calculations.

Since the fugitive upstream emissions for coal depends on the source (underground or surface mines), project participants are requested to use the emission factor that corresponds to the predominant source

(underground or surface) currently used by coal-based power plants in the region. Israel purchases coal from a variety of suppliers, which includes both surface- and underground-mined coal. Information is not available on the coal's origins and therefore, it is not known how much of the coal is mined in each manner. Calculations were made using the values provided of fugitive upstream emissions for both underground and surface coal mining and higher leakage resulted from using surface-mined coal. It is more conservative to calculate the leakage emissions from coal assuming that all the coal is surface-mined. Therefore, the calculation for $LE_{CH4,y}$ assumes that all coal used in Israel is from surface mines.

Table 1: Default emission factors for fugitive CH_4 upstream emissions

Activity	Unit	Default emission factor	Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines*
Coal			
Underground mining	t CH4 / kt coal	13.4	Equations 1 and 4, p. 1.105 and 1.110
Surface mining	t CH4 / kt coal	0.8	Equations 2 and 4, p.1.108 and 1.110
Oil			
Production	t CH4 / PJ	2.5	Tables 1-60 to 1-64, p. 1.129 - 1.131
Transport, refining and storage	t CH4 / PJ	1.6	Tables 1-60 to 1-64, p. 1.129 - 1.131
Total	t CH4 / PJ	4.1	
Natural gas			
USA and Canada			
Production	t CH4 / PJ	72	Table 1-60, p. 1.129
Processing, transport and distribution	t CH4 / PJ	88	Table 1-60, p. 1.129
Total	t CH4 / PJ	160	
Eastern Europe and former USSR			
Production	t CH4 / PJ	393	Table 1-61, p. 1.129
Processing, transport and distribution	t CH4 / PJ	528	Table 1-61, p. 1.129
Total	t CH4 / PJ	921	
Western Europe			
Production	t CH4 / PJ	21	Table 1-62, p. 1.130
Processing, transport and distribution	t CH4 / PJ	85	Table 1-62, p. 1.130
Total	t CH4 / PJ	105	
Other oil exporting countries / Rest of world			
Production	t CH4 / PJ	68	Table 1-63 and 1-64, p. 1.130 and 1.131
Processing, transport and distribution	t CH4 / PJ	228	Table 1-63 and 1-64, p. 1.130 and 1.131
Total	t CH4 / PJ	296	

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range.

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO2,y} = FC_y \cdot EF_{CO2,upstream,LNG} \quad (7)$$

Where:

$LE_{LNG,CO2,y}$	Leakage emissions due to fossil fuel combustion/electricity consumption	tCO_2e

	associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y.	
FC_y	Quantity of natural gas combusted in the project plant during the year y.	m³
$EF_{CO2,upstream,LNG}$	Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system.	tCO_2e/m^3

Where reliable and accurate data on upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 t CO_2/TJ as a rough approximation.

It is expected that no LNG will be used in the project activity; therefore, no calculation of leakage as a result of liquefying the natural gas was made.

According to AM0029, where total net leakage effects are negative (*LEy* < 0), project participants should assume LEy = 0.

Emission Reductions

To calculate the emission reductions the project participant shall apply the following equation:

$$ERy = BEy – PEy – LEy \quad (8)$$

ERy	Emissions reductions in year y	tCO_2e
BEy	Emissions in the baseline scenario in year y	tCO_2e
PEy	Emissions in the project scenario in year y	tCO_2e
LEy	Leakage in year y	tCO_2e

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	GWP_{CH4}
Data unit:	tCO_2/tCH_4
Description:	Global warming potential of methane
Source of data used:	UNFCCC
Value applied:	21
Justification of the choice of data or description of measurement methods and procedures actually applied :	
Any comment:	

B.6.3 Ex-ante calculation of emission reductions:

Baseline Emissions:

Baseline emissions were calculated using the following formula:

$BE_y = EG_{PJ,y} * EF_{BL,CO2,y}$

$EF_{BL,CO2}$ was calculated according to ACM0002 version 06, with a result of 0.937 tCO_2/MWh. Full calculations of this parameter are available in Annex 3. The $EG_{PJ,y}$ has been estimated as shown to the DOE in the plant's business model.

	$EG_{PJ,y}$ (MWh/yr)	$EF_{BL,CO2,y}$ (tCO_2/MWh)	BEy (tCO_2)
2011	1,503,128	0.937	1,408,015
2012	1,503,128		1,408,015
2013	1,503,128		1,408,015
2014	1,503,128		1,408,015
2015	1,503,128		1,408,015
2016	1,503,128		1,408,015
2017	1,503,128		1,408,015
2018	1,503,128		1,408,015
2019	1,503,128		1,408,015
2020	1,503,128		1,408,015

Project Emissions:

Project emissions will be calculated according to the formula $PE_y = \sum_f FC_{f,y} * COEF_{f,y}$, with fuel consumption in m^3 and the $COEF_{f,y}$ as tCO_2/m^3. For the *ex ante* calculation of project emissions, the only data available is for the amount of energy (in joules) that the power plant will require throughout the crediting period, not for the amount of natural gas in m^3. Therefore, we have calculated project emissions with $FC_{f,y}$ in TJ and $COEF_{f,y}$ in tCO_2/TJ.

	$FC_{f,y}$ (TJ)	$COEF_{f,y}$ (tCO_2/TJ)	PE_y (tCO_2)
2011	14,129	56.1	792,617
2012	14,129		792,617
2013	14,129		792,617
2014	14,129		792,617
2015	14,129		792,617
2016	14,129		792,617
2017	14,129		792,617
2018	14,129		792,617
2019	14,129		792,617
2020	14,129		792,617

The CO_2 emissions coefficient for natural gas will be calculated by: $COEF_{f,y} = \Sigma NCV_y * EF_{CO2,f,y} * OXID_f$. As explained in the monitoring section, the NCV of the gas will be monitored during the project years using a gas chromatograph. Since the project hasn't began yet and only for the ex-ante calculations, an IPCC 2006 emission factor will be used for the estimation of project emissions.

NCV_y (TJ/TJ)	$EF_{CO2,f,y}$ (tCO_2/TJ)	$OXID_f$	$COEF_{f,y}$
1	56.1	1	56.1

Leakage Calculations

Leakage from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$$

It is expected that no LNG will be used in the project activity and therefore, $LE_{LNG,CO2,y}$ is assumed to be 0.

<u>Fugitive methane emissions</u>

The methodology states that when reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is not available, project participants should use the default values provided in Table 2 of the methodology (and included in the body of the PDD as Table 1). Where default values from this table are used, the natural gas emission factors for the location of the project activity should be used. The methodology states that "US/Canada values may be used in cases where it can be shown that the relevant system element (gas production and/or processing/ transmission/distribution) is predominantly of recent vintage and built and operated to international standards." The natural gas production, processing and distribution systems in the region where the project is taking place are very new, since natural gas was only recently discovered and the entire infrastructure is new, as well. The system operates on the Dutch standard (NEN 3650 requirements for steel, "pipeline transportation systems" ("Dutch standard"). The DOE will be shown proof that the Israeli Natural Gas Lines operate according to this standard as regulated by the Israeli law. Therefore, the US/Canada values have been used.

For the purpose of estimating fugitive CH_4 emissions, the quantity of natural gas consumed by the project is multiplied with an emission factor for fugitive CH_4 emissions ($EF_{NG,\ upstream,CH4}$) from natural gas consumption. The $EF_{NG,\ upstream,CH4}$ used in the calculation is the default value for the US/Canada provided by AM0029 and subtracts the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4}$$

Where:

Year	FC_y (PJ)	NCV_{NG} (PJ/PJ)	$EF_{NG,upstream,CH4}$ (tCH_4/PJ)	$EF_{BL,upstream,CH4}$ (tCH_4/MWh)	$EG_{PJ,y}$ (MWh/yr)	GWP_{CH4} (tCO_2/tCH_4)	$LE_{CH4,y}$

2011	14.129				1,503,128		37,154
2012	14.129				1,503,128		37,154
2013	14.129				1,503,128		37,154
2014	14.129				1,503,128		37,154
2015	14.129	1	160	**0.00033**	1,503,128	21	37,154
2016	14.129				1,503,128		37,154
2017	14.129				1,503,128		37,154
2018	14.129				1,503,128		37,154
2019	14.129				1,503,128		37,154
2020	14.129				1,503,128		37,154

For the *ex post* calculation for leakage, FC_y will be given in m^3. However, for the *ex ante* calculation the estimation of the amount of energy needed, in Joules, is the only data available. Therefore, for the *ex ante* calculation of the project's leakage, FC_y is given in PJ, while NCV_{NG}, which will be given in PJ/ m^3 for the *ex post* calculation of project leakage, has a value of 1 because FC_y is already given in a unit that accounts for its energy content.

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) should be calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) used in the PDD to calculate baseline emissions. The Combined Margin was used for $EC_{BL,CO2}$ (please see above) and therefore, Option 2 was used, as follows:

Option 2: Combined Margin:
$$EF_{BL,upstream,CH4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH4}}{\sum_i EG_i}$$

Where:

$FF_{j,k}$	Coal (kt) j=Rutenberg power plant[27]	17,290 ktonne
	HFO (PJ) j=Rutenberg power plant	0.98 PJ
	Diesel (PJ) j=Askogen, Gezer, Atarot, Hagit, Alon Tavor and Rutenberg power plants	44.69 PJ
	NG (PJ) No power plants in the BM used natural gas in 2004-2006	0 PJ
NCV_k	HFO	(0.00004019 PJ/tonne)
	Diesel	(0.000043 PJ/tonne)
	NG	(0.000048 PJ/tonne)
EG_j (MWh/y)		54,771,679
EG_i (MWh/y)		145,721,911
$EF_{k,upstream,CH4}$	Surface coal mining	0.8

[27] All the data regarding electricity generation in Israel (including year of commission and amount of fuel used at each power plant) is available in Annex 3 to this document.

	(tCH_4/kt)	
	Oil (tCH_4/PJ)	4.1
	NG – US/Canada (tCH_4/PJ)	160
$FF_{i,k}$	Coal (kt) i=all power plants in the grid	38,036 kt
	HFO (PJ) i=all power plants in the grid	105.52 PJ
	Diesel (PJ) i=all power plants in the grid	68.89 PJ
	NG (PJ) i=all power plants in the grid	167.65 PJ

Since the fugitive upstream emissions for coal depends on its source (underground or surface mines), the emission factor that should be used should corresponds to the predominant source (underground or surface) currently used by coal-based power plants in the region. Israel purchases coal from a variety of suppliers, which includes both surface- and underground-mined coal. Information is not available on the sources of the coal and therefore, it is not known how much of the coal is mined in each manner. Calculations were made using the values provided of fugitive upstream emissions for both underground and surface coal mining and higher leakage resulted from using surface-mined coal. It is more conservative to calculate the leakage emissions from coal assuming that all the coal is surface-mined. Therefore, the calculation for $LE_{CH4,y}$ assumes that all coal used in Israel is from surface mines.

Using the values above, $EF_{BL,upstream,CH4}$ was calculated as being **0.00033 tCH_4/MWh**.

Using the values above, the leakage for the project, $LE_{CH4,y}$ was calculated to be:

	$LE_{CH4,y}$
2011	37,154
2012	37,154
2013	37,154
2014	37,154
2015	37,154
2016	37,154
2017	37,154
2018	37,154
2019	37,154
2020	37,154

B.6.4 Summary of the ex-ante estimation of emission reductions:

Year	Estimation of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of Leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)

2011	792,617	1,408,015	37,154	578,243
2012	792,617	1,408,015	37,154	578,243
2013	792,617	1,408,015	37,154	578,243
2014	792,617	1,408,015	37,154	578,243
2015	792,617	1,408,015	37,154	578,243
2016	792,617	1,408,015	37,154	578,243
2017	792,617	1,408,015	37,154	578,243
2018	792,617	1,408,015	37,154	578,243
2019	792,617	1,408,015	37,154	578,243
2020	792,617	1,408,015	37,154	578,243
Total (tCO_2e)				5,782,430

B.7 Application of the monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

Data / Parameter:	$FC_{f,y}$
Data unit:	m^3/hr
Description:	Annual quantity of natural gas consumed in the project activity
Source of data to be used:	Turbine and ultrasonic meter readings
Value of data applied for the purpose of calculating expected emission reductions in section B.5	For the purpose of ex ante emissions calculations, the amount of natural gas that would be consumed in the project was given in TJ. Cubic metres will be used in the actual ex post calculations. <table><tr><th></th><th>FC_{NG,y} (TJ)</th></tr><tr><td>2011</td><td>14,129</td></tr><tr><td>2012</td><td>14,129</td></tr><tr><td>2013</td><td>14,129</td></tr><tr><td>2014</td><td>14,129</td></tr><tr><td>2015</td><td>14,129</td></tr><tr><td>2016</td><td>14,129</td></tr><tr><td>2017</td><td>14,129</td></tr><tr><td>2018</td><td>14,129</td></tr><tr><td>2019</td><td>14,129</td></tr><tr><td>2020</td><td>14,129</td></tr></table>
Description of measurement methods and procedures to be applied:	The PLC system, which continuously monitors total natural gas consumption, is capable of converting the reading into m^3 per period of time. The period of time can be set as required. The natural gas lines have a system of two pipelines running to the PRMS in order to insure availability in case of a problem with one of the pipes. A Turbine meter and an Ultrasonic meter will be installed on each pipeline in order to verify and cross-check their readings.
QA/QC procedures to be applied:	The natural gas consumed will be measured by flow meter(s) that will measure the gas flow. All flow meters will be subject to calibrations and on going maintenance operations as dictated by law in the Natural Gas purchase agreement moderated by the Ministry of Infrastructure. Appendix 3 of the natural

	gas purchase agreement discussing the measurement procedures can be found in Appendix 4 of this document. The full agreement will be presented to the DOE. The natural gas lines have a system of two pipelines running to the PRMS, in order to insure availability in case of a problem with one of the pipes. A Turbine meter and an Ultrasonic meter are installed on each pipeline in order to verify and cross-check their readings. Natural gas consumption will be measured and monitored by both the supplier and the project for the purpose of cross-verification.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$NCV_{f,y}$
Data unit:	TJ/m^3
Description:	Average net calorific value per volume unit of natural gas
Source of data to be used:	Monitored using a gas chromatograph.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This value was not available for the *ex ante* calculations. Therefore, the IPCC value of 0.04522 TJ/t was used for the PDD.
Description of measurement methods and procedures to be applied:	The NCV is measured in British Thermal Units (BTU). The value in BTU will be converted to joules using the value 1,055.0559 J/BTU, as given by http://www.onlineconversion.com. The reading of the gas chromatograph will be continuous and readings will be recorded at least fortnightly.
QA/QC procedures to be applied:	No additional QA/QC procedures are required.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$COEF_y$
Data unit:	tCO_2/m^3
Description:	CO_2 emission coefficient
Source of data to be used:	Calculated as per equation 2 in the PDD
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This value was not available for the *ex ante* calculations. Therefore, the IPCC value of 56.1 tCO_2/TJ was used for the PDD.
Description of measurement methods and procedures to be applied:	Will be calculated annually during the crediting period as per equation 2.
QA/QC procedures to	No additional QA/QC procedures are required.

be applied:	
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh/yr
Description:	Net electricity supplied by the project to the end user per period y.
Source of data to be used:	Data measured continuously and recorded from the energy meters that will be installed at the power plant
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2011: 1,503,128 2012: 1,503,128 2013: 1,503,128 2014: 1,503,128 2015: 1,503,128 2016: 1,503,128 2017: 1,503,128 2018: 1,503,128 2019: 1,503,128 2020: 1,503,128
Description of measurement methods and procedures to be applied:	Electricity gauges will be used to measure the amount of electricity generated. Billing to clients will be based on the reading of the electricity gauges. IPPs are required by law in Israel to continuously read meters and store metering information at the 30-minute level. The IEC is held accountable as the ESP (essential services provider) to read the metering data stored at the IPP's meter. The ESP is also authorized to read the competitive producer's meter remotely whenever necessary to fulfil its obligations as stipulated in its license.[28]
QA/QC procedures to be applied:	The electricity gauge will be calibrated once per year.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$EF_{CO2,f,y}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor for natural gas
Source of data to be used:	Local/regional/global data. If this variable is not available from the fuel supplier or a regional body, the value provided by the IPCC will be used
Value of data applied for the purpose of calculating expected emission reductions in section B.5	56.1 tCO_2/TJ. Currently, no $EF_{CO2,f,y}$ provided by the natural gas supplier or by the Host Country. There are no local or national estimates available for this value in Israel. Therefore, until such a value is provided for $EF_{CO2,f,y}$ the IPCC value will be used.
Description of measurement methods	Will be estimated as specified in AM0029.

[28] http://www.pua.gov.il/frame.html

Translated version of the "Amot Mida and Tariffs DOCUMENT for IPPs" was provided to the DOE

and procedures to be applied:	
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$OXID_{f,}$
Data unit:	%
Description:	Oxidation factor of natural gas
Source of data to be used:	IPCC 2006
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1.0
Description of measurement methods and procedures to be applied:	The methodology states that IPCC default oxidation factors may be used.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$F_{i,j,y}$
Data unit:	tonnes or m^3 (depending on fuel type)
Description:	The amount of fuel i (in a mass or volume unit) consumed by relevant power sources j (in the operating margin) in year(s) y
Source of data to be used:	Israel Electric Company
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Coal [ton]: 38,035,530; HFO [ton]: 2,625,616; Diesel [ton]: 1,602,153; NG [ton]: 3,492,637
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Coal [ton]	HFO [ton]	Diesel [ton]	NG [ton]
38,035,530	2,625,616	1,602,153	3,492,637

Data / Parameter:	$COEF_{i,j\ y}$

Data unit:	tCO_2/mass or volume unit of the fuel
Description:	The CO_2 emission coefficient of fuel i, taking into account the carbon content of the fuels used by relevant power sources j (in the operating margin) and the percent oxidation of the fuel in year(s) y
Source of data to be used:	Calculated using IPCC 2006 values when plant or country specific values are not available.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Please see Annex 3.
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$GEN_{j,y}$
Data unit:	MWh/y
Description:	The electricity delivered to the grid by source j (PP in the operating margin).
Source of data to be used:	Israel Electric Company
Value of data applied for the purpose of calculating expected emission reductions in section B.5	145,721,911 MWh
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$F_{i,m,y}$
Data unit:	tonnes or m^3 (depending on fuel type)
Description:	The amount of fuel i (in a mass or volume unit) consumed by relevant plant m (in the build margin) in year(s) y,
Source of data to be used:	Israel Electric Company
Value of data applied for the purpose of calculating expected	Coal [ton] | HFO [ton] | Diesel [ton] | NG [ton]

emission reductions in section B.5	17,290,326 | 24,324 | 1,039,245 | 0
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$COEF_{i,m\ y}$
Data unit:	tCO_2/mass or volume unit of the fuel
Description:	the CO_2 emission coefficient of fuel i, taking into account the carbon content of the fuels used by relevant plant m (in the build margin) and the percent oxidation of the fuel in year(s) y
Source of data to be used:	Calculated using IPCC 2006 values when plant or country specific values are not available.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Please see Annex 3.
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$GEN_{m,y}$
Data unit:	MWh/y
Description:	The electricity delivered to the grid by plant m (in the build margin).
Source of data to be used:	Israel Electric Company
Value of data applied for the purpose of calculating expected emission reductions in section B.5	54,771,679 MWh
Description of measurement methods and procedures to be applied:	Three years of data is acquired from the IEC. Calculations made according to ACM0002, version 6.

QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

Data / Parameter:	$EF_{BL,CO2,y}$
Data unit:	tCO_2/MWh
Description:	The carbon emission factor of the electricity generated. This is the combined margin (CM) of the build (BM) and operating margins (OM) calculated according to ACM0002 version 06.
Source of data to be used:	Calculations of the BM and OM according to ACM0002 version 06 and AM0029. Data for these calculations is acquired from the IEC.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.937
Description of measurement methods and procedures to be applied:	Data will be acquired from the IEC for ex post calculations. Calculations made according to ACM0002 version 06 and AM0029 version 1.1.
QA/QC procedures to be applied:	There are no QA/QC procedures required for this variable.
Any comment:	All data will be stored electronically for the duration of the crediting period plus two additional years.

B.7.2 Description of the monitoring plan:

The project is only expected to be operational by 2011. Operation and maintenance procedures for the power plant will be developed, according to current best practices, to meet the power plant's scheduled date of operations.

Monitoring of parameters required to determine emission reductions (parameters listed above in section B.7.1) will be undertaken by the designated engineer(s) on-site and/or other authorised individuals. The project will be committed, by its various licenses to build and operate, to perform additional detailed and independently audited monitoring, of performance and emissions, to satisfy regulatory and permitting requirements as well as its commercial contracts as to NG supply and electricity and steam delivery. The project's monitoring plan will follow international standards and will include (but is not limited to) data monitoring, regular equipment maintenance and calibrations, data verification and troubleshooting measures.

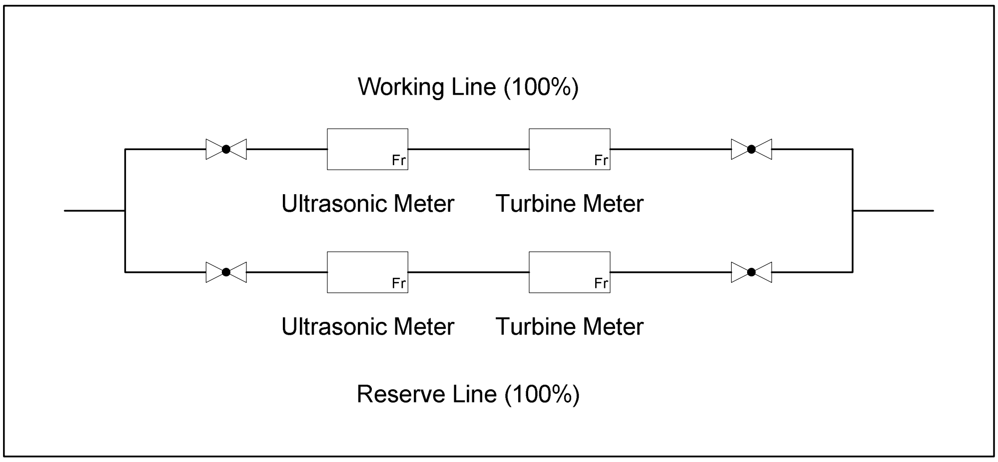
The monitoring procedures for the project activity set the credibility by which the project's performance and GHG-reductions are measured. The monitoring procedures include developing data collection methods and means of data analysis to determine GHG reductions. Equally important are the operating procedures developed to ensure the proper operation of the project activity.

The protocol provides requirements for data measurement, collection and calculation to ensure that project managers and operational staff collect credible and quality data needed for the project activity. The latest state-of-the-art monitoring equipment will be used to measure, record, report, monitor and control various key parameters. The parameters to be monitored are quantity and quality of natural gas, the total amount of electricity generated and the amount of electricity exported to each consumer. Measurement gauges for natural gas and electricity will be calibrated regularly to ensure accurate data collection.

Data: Natural Gas

The natural gas supply will be measured by an ultrasonic meter and a turbine meter, which are installed on two parallel pipes at the entrance to the power station. All components of the gas monitoring system (gas meters, gas chromatograph, etc) will be subject to calibrations and ongoing maintenance operations as dictated by law in the Natural Gas Purchase Agreement determined by the Ministry of Infrastructure. Appendix 3 of the Natural Gas Purchase Agreement discussing the measurement procedures can be found in Appendix 4 of this document.

All maintenance procedures for the gas system are dictated by law in the Natural Gas Purchase Agreement and will be undertaken by Israeli Natural Gas Lines (INGL). INGL must report its operation and maintenance procedures, including calibration, to Integrated Energy, who ensures that all procedures are carried out according to the agreement. The full Natural Gas Purchase Agreement will be presented to the DOE.



Gas will flow through one pipe. Natural gas consumption is sent to and stored in the Distribution Control System and consumption data is received monthly by the power plant in an invoice from INGL. Once a month, this data will be aggregated with the other CDM parameters into a CDM report by the CDM project manager, who will review the data and apply Q&A procedures to ensure data integrity. This data will be stored electronically and in hard copy at the power plant for the duration of the project activity, plus two years.

Data: Electricity

The power plant's revenue is based on the amount of electricity it exports (net electricity). Therefore, the quality of the electricity meters is very important. Electricity meters will measure the amount of electricity exported to each client. The electricity meters will be calibrated annually. As this is a grid

connected plant, the process of monitoring the electricity output of the plant will be supervised by the Israeli Electric Company. IPPs are required by law in Israel to continuously read meters and store metering information at the 30-minute level. The IEC is held accountable as the ESP (essential services provider) to read the metering data stored at the IPP's meter. The ESP is also authorized to read the competitive producer's meter remotely whenever necessary to fulfil its obligations as stipulated in its license.[29]

Training

Training procedures for the proper operation of the power plant and its monitoring equipment will be developed to meet the needs of Integrated Energy and the CDM process.

Clarification

As explained in section B.2 of the PDD, the power plant's license does not permit the use of a fuel other than natural gas except when ordered to do so by the government in the case of a national emergency. All NG power plants of over a 100 MW capacity are required by the Israeli law to be duel fueled for emergency purposes. In the unlikely event that such an emergency arises and a fuel other than natural gas is used, no emission reductions will be claimed for the electricity generated. In the project only natural gas will be used and no other fuel will be used for auxiliary purposes.

B.8 Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies)

The application of the baseline and monitoring methodology was completed by EcoTraders on July 2007. Contact information of the responsible entity, a project participant, is available in Annex 1.

All relevant data and information presented in the PDD pertains to the period in which the baseline study was conducted.

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:

Estimated 01/01/2009

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

20 years, 0 months.

[29] http://www.pua.gov.il/frame.html

Translated version of the "Amot Mida and Tariffs DOCUMENT for IPPs" was provided to the DOE

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:

>>

C.2.1.2. Length of the first crediting period:

>>

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/01/2011 or the date that the power plant begins regular operations (after the commissioning period).

C.2.2.2. Length:

10 years, 0 months.

SECTION D. Environmental impacts

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

The Integrated Energy power plant will be constructed with the confines of the Hadera industrial zone on land already designated for industrial purposes, and not in or near a current or potentially future residential area.

The power plant will be located in an industrial area where there are many businesses that combust fossil fuels, such as propane, low-sulphur HFO and coal. The largest consumer of fossil fuel in the area is the Orot Rabin IEC power plant, which is primarily coal-fired and has a capacity of 2,590 MW (the largest power plant in Israel).[30] In Section D.2 the results of the EIA are discussed and it is shown that the environmental impacts from the project activity are not considered to be significant.

The power plant is located on the Mediterranean coast and therefore, no transboundary impacts are expected.

D.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:

There are no significant environmental impacts expected from the project, as demonstrated in the table below that summarises the environmental impact assessment conducted for the power plant.

[30] Israel Electric Company's Statistical Report, 2005, p.4. Available in Hebrew at http://www.israel-electric.co.il/Static/WorkFolder/Investors/Statistic%20Report%202005.pdf

As explained in the "Regulations for Planning and Construction (Environmental Impact Assessments), 2003", an environmental impact assessment (EIA) is mandatory for new power plants. Accordingly, an EIA was carried out for the Integrated Energy power plant by the firm Y Goldschmid, Environmental Engineering and Design Ltd[31]. The statement was completed and submitted to the client on December 13, 2005.

The determinations of the EIA are as follows:

Environmental Issue	Power Plant	Significant Impact?
Air pollution	Hadera suffers from air pollution, particularly SO_x emissions. The main contributor to this air pollution is the Orot Rabin power plant. The Integrated Energy power plant will not contribute significantly to air pollution in the area. The Integrated Energy power plant should not cause excessive emissions of NO_x or particulate matter.	No significant impact on air quality.
Waste water	Wastewater that is contaminated by oil will be treated and the oil separated from the water. The purified water will be delivered to the nearby stream and the oil will be recycled.	No significant impact on water quality or water availability.
Scarce water resources	The power plant will use the treated waste water from the American Israel Paper Mill water purifying facility. The brine from the cooling towers will be delivered to the sea.	No significant impact on water quality or water availability.
Scare land resources	The power plant will be constructed on land designated for industrial purposes.	No. The power plant will not impact the Host Country's scarce land resources.
Noise pollution	The power plant will adhere to noise regulations.	No. The power plant will not cause noise pollution.

The EIA determined that the Integrated Energy power plant will not have significant, negative impacts on the environment in the Host Country.

SECTION E. Stakeholders' comments

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

An information brochure about the Integrated Energy power plant and the Kyoto Protocol was sent by post in early January 2007 to the following list of stakeholders:

1. Mr. Haim Avitan – Mayor of Hadera.
2. Mr. Etay Enbaar – CEO of the Hadera Municipality.
3. Mr. Beni Mamka – Head Engineer of Hadera.
4. Mr. Roman Gisher – Vice Mayor of Hadera.
5. Dr. Pessah – Member of the Hadera City Council.
6. Mr. Giora Shahar - Member of the Hadera City Council.

[31] Company website: http://www.y-goldshmid.com/en-default.htm.

7. Mr. Yeruham Lakritz – CEO of the City Union of Environmental Protection.
8. Mrs. Gloria Efrati – Head of Industries and Business Licenses (City Union of Environmental Protection).
9. Mr. Arie Yogev – Head of Radiation and Noise (City Union of Environmental Protection).
10. Mrs. Ofra Livne – Planner (City Union of Environmental Protection).
11. Mr. Roman Shumayev – Representative of the neighbourhood committee.
12. Mr. Rotery – President of the Hadera Bureau.
13. Mr. Rami Zilbershtein – CEO of the Sharon Region New Workers Union. Adjacent region.
14. Mr. Yossi Anglister – CEO Alliance- Adjacent factory
15. Mr. Israel Osobitzki – CEO Comba- Adjacent factory
16. Mr. Ilan Sade – CEO Menashe Regional Counsel. Adjacent region.
17. Mr. Arie Leybowitz – CEO AIPM Workers Union.
18. Local Representatives of the surrounding neighbourhoods.

The list includes high officials from the local municipality, environment unions, NGOs, CEOs of large businesses from the surrounding area and local residents, thus representing in the best manner all relevant stakeholders.
The brochure, which was presented to the DOE during validation, explains the problem of global warming and the international solutions presented by the Kyoto protocol and the CDM mechanism. The information sheet describes the power plant project in Hadera, its environmental benefits and contribution to sustainable development in Israel.

The stakeholders were invited to submit comments over the internet regarding the project via the e-mail address provided in the brochure. The web site was open from January 10, 2007 for a period of 30 days for stakeholders to send comments or questions. Any questions and comments that would have been sent would have receive responses from the CDM advisor.

E.2. Summary of the comments received:

No comments were received.

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

No comments or questions were received.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	EcoTraders Ltd.
Street/P.O.Box:	Saadia Gaon 24, 9th Floor
Building:	
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Street/P.O.Box:	142
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City:	Hadera
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Postfix/ZIP:	38101
Country:	Israel
Telephone:	972-4-634-9358
FAX:	972-4-634-9254
E-Mail:	Gideon@aipm.co.il
URL:	
Represented by:	Gideon Liberman
Title:	Operation Vice President
Salutation:	
Last Name:	Liberman
Middle Name:	
First Name:	Gideon

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There is no public funding from an Annex I Party to the UNFCCC provided for this project.

Annex 3

BASELINE INFORMATION

Baseline emissions are calculated using the energy generation in the project activity ($EG_{PJ,y}$) and the grid emission factor of the baseline scenario ($EF_{Bl,CO2,y}$).

The grid emission factor of the baseline scenario ($EF_{Bl,CO2,y}$) is determined according to ACM0002 version 06. The data was obtained from the Israel Electric Company. The methodology requires that the estimation of the baseline emission factor be the lowest of the following three options:

Option 1. The Build Margin, calculated using ACM0002 version 06
Option 2: The Combined Margin, calculated using ACM0002 version 06 and a 50/50 ratio of BM/OM
Option 3: The emission factor of the technology and fuel identified as the most likely baseline scenario under "Identification of the baseline scenario"

Option 1: Build Margin (BM) and **Option 2: Combined Margin (CM)**

Step 1: Calculation of the OM ($EF_{OM,y}$) based on one of the four following methods:
(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch Data Analysis OM, or
(d) Average OM.

The Dispatch Data Analysis method should be the first choice and requires the following information:

c. "The grid system dispatch order of operation for each power plant of the system"; and
d. "The amount of power (MWh) that is dispatched from all plants in the system during each hour that the project activity is operating".

Dispatch Data Analysis was not chosen for the calculation of the OM because the required information is not publicly available. The only publicly available information pertaining to the Host Country's national grid is the total yearly amount of electricity produced and the fuels used by each of the grid connected plants (which is the information needed for the simple OM method). According to the Meth Panel's response to clarification request AM_CLA_0037, only if the required information for Dispatch Data Analysis is not available may the Dispatch Data Analysis method not be used. The Israel Electric Company publicly provides data of electricity generation by and fuel consumption of each power plant, but does not provide the grid system dispatch order of operation for each plant or the amount of power dispatched from each plant. Therefore, the OM could not be calculated using Dispatch Data Analysis.

The Simple OM method (a) was chosen because low-operating cost and must run resources, which typically include hydro, geothermal, wind and nuclear power generation either are not used in the host country (nuclear and geothermal) or contribute negligibly to the grid. As described above in section B.4, 0.09% of the total electricity generation in the Host Country is from renewable sources. Total wind capacity is 6.2MW; total hydro capacity is 5.5 MW; and total solar photovoltaics generate 1.5 million kWh (0.003% of total electricity generation).[32]

[32] Yaniv Ronen "Electricity Generation from Alternative Fuels in Israel". Presented to the Israeli government, Committee for Science and Technology, January 15, 2007. www.knesset.gov.il/mmm/data/docs/m01650.doc. Translation presented to the DOE. Accessed on December 6, 2007.

The OM is calculated as follows:

$$EF_{OM,y} = \frac{\sum_{i,j} F_{i,j,y} . COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

Where:

$F_{i,j,y}$	Amount of fuel i consumed by relevant power sources j in years y	t
$COEF_{i,j,y}$	CO_2 emission coefficient of fuel i, taking into account the carbon content of the the fuel and the percent oxidation of the fuel	tCO_2/t
$GEN_{j,y}$	Electricity delivered to the grid by source j	MWh

Power Stations (Power source *j*)	Fuel[33] (Fuel i)	Fuel consumption (t/year) (Amount of fuel *i* consumed in year *y*)			Electricity generation (MWh/year) ($GEN_{j,y}$ – Electricity delivered to grid)		
		2004	2005	2006	2004	2005	2006
Etgal (Askogen)	Diesel	21,828	23,975	23,006	101,508	111,767	112,162
Gezer	Diesel	41,826	109,174	120,752	147,170	396,267	443,678
Atarot	Diesel	959	4,486	4,552	2,760	13,700	13,730
Hagit	Diesel	144,867	200,377	221,789	748,798	1,041,372	1,100,033
Alon Tavor	Diesel	21,762	50,346	42,325	67,777	164,471	141,121
Ruthenberg	Coal	5,901,796	5,804,143	5,584,387	17,197,184	16,941,628	16,026,553
	HFO	--	19,717	4,607			
	Diesel	--	3,337	3,884			
Tzafit	Diesel	7,446	47,826	34,618	22,663	153,747	111,696
Ramat Hovav	Diesel	98,062	155,554	173,494	485,795	748,460	880,617
Orot Rabin	Coal	6,814,862	6,847,955	7,082,387	19,256,078	19,185,765	19,708,689
	HFO	6,778	10,585	--			
	Diesel	--	2,397	2,827			
Eilat	Diesel	6,689	11,573	10,695	16,360	27,976	28,268
Eshkol	HFO	309,000	115,627	118,169	5,598,000	6,446,086	8,287,476
	NG	823,000	1,126,863	1,299,220			
	Diesel	--	98	153			
Kinarot	Diesel	1,990	3,551	1,670	5,067	8,699	4,208

[33] HFO refers to heavy (residual) fuel oil.

Reading*)	HFO	407,297	391,486	112,019	1,760,622		
	Diesel	--	705	256		1,702,721	1,765,508
	NG	--	--	243,554			
Haifa	HFO	369,397	343,485	417,449	1,576,328	1,430,464	1,738,940
	Diesel	--	2,487	818			

	$COEF_{i,j,y}$ (tCO_2/t) (includes oxidation factor)	Source
Coal	2.8797	IPCC 1996
HFO	3.0811	
Diesel	3.1801	
Natural Gas	2.5265	

Total electricity generation for 2004-2006	145,723,917	MWh
Total emissions for 2004-2006	131,539,501	tCO_2
Operation Margin (OM)	0.903	tCO_2/MWh

Step 2: Calculation of the BM ($EF_{BM,y}$) using one of the two following options:

(The choice of Option 1 or Option 2 must be specified in the PDD and cannot be changed during the crediting period.)

Option 1:
Calculate the Build Margin emission factor $EF_{BM,y}$ ex-ante based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. The sample group *m* consists of either:

a) the five power plants that have been built most recently, or
b) the power plant capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. If 20% falls on part capacity of a plant, that plant is fully included in the calculation.

Project participants should use from these two options that sample group that comprises the larger annual generation.

Option 2:
For the first crediting period, the Build Margin emission factor $EF_{BM,y}$ must be updated annually ex-post for the year in which actual project generation and associated emissions reductions occur. For subsequent crediting periods, $EF_{BM,y}$ should be calculated ex-ante, as described in option 1 above. The sample group *m* consists of either:

a) the five power plants that have been built most recently, or
b) the power plant capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. If 20% falls on part capacity of a plant, that plant is fully included in the calculation.

Project participants should use from these two options that sample group that comprises the larger annual generation.

For the PDD and the validation, the calculation of the BM for the Integrated Energy project was made ex ante with the most recent information available at the time of the PDD submission. For the project itself, Option 2 will be used to calculate the BM as required by methodology AM0029, which requires the calculation of the build margin emission factor ex post.

Total grid electricity generation:

Power Stations (Power source *j*)	Owner	Year of Commission (by date)	Electricity generation (MWh/year)		
			2004	2005	2006
Etgal (Askogen)	Private	1998	101,508	111,767	112,162
Gezer	State	1997	147,170	396,267	443,678
Atarot	State	1997	2,760	13,700	13,730
Hagit	State	1994	748,798	1,041,372	1,100,033
Alon Tavor	State	1991	67,777	164,471	141,121
Ruthenberg	State	1990	17,197,184	16,941,628	16,026,553
Tzafit	State	1990	22,663	153,747	111,696
Ramat Hovav	State	1989	485,795	748,460	880,617
Orot Rabin	State	1981	19,256,078	19,185,765	19,708,689
Eilat	State	1980	16,360	27,976	28,268
Eshkol	State	1977	5,598,000	6,446,086	8,287,476
Kinarot	State	1975	5,067	8,699	4,208
Reading*)	State	1970	1,760,622	1,702,721	1,765,508
Haifa	State	1961	1,576,328	1,430,464	1,738,940
Total (per year)			**46,986,110**	**48,373,122**	**50,364,685**

20% of Total Electricity Generated in 2006[34]	10,072,937

The five most recently commissioned power plants in Israel:

Power Stations (Power source *j*)	Owner	Year of Commission (by date)	Fuel ($F_{i,j,y}$)	Electricity generation (MWh/year)		
				2004	2005	2006
Etgal (Askogen)	Private	1998	Diesel	101,508	111,767	112,162
Gezer	State	1997	Diesel	147,170	396,267	443,678
Atarot	State	1997	Diesel	2,760	13,700	13,730
Hagit	State	1994	Diesel	748,798	1,041,372	1,100,033
Alon Tavor	State	1991	Diesel	67,777	164,471	141,121
Total generation capacity in 2006				1,810,724		

The total generating capacity of these five plants is below the 20% generating capacity of the entire grid from 2006. Therefore, other power plants must be included in the calculation for the BM:

Power Stations (Power source *j*)	Owner	Year of Commission (by date)	Fuel ($F_{i,j,y}$)	Electricity generation (MWh/year)		
				2004	2005	2006
Etgal (Askogen)	Private	1998	Diesel	101,508	111,767	112,162
Gezer	State	1997	Diesel	147,170	396,267	443,678
Atarot	State	1997	Diesel	2,760	13,700	13,730
Hagit	State	1994	Diesel	748,798	1,041,372	1,100,033
Alon Tavor	State	1991	Diesel	67,777	164,471	141,121
Ruthenberg	State	1990	Coal HFO Diesel	17,197,184	16,941,628	16,026,553
Total generation capacity in 2006				**17,837,277**		

Therefore, the sample group *m* for the calculation of the BM includes six power plants because their total generation capacity in 2006 is greater than the 20% of electricity generated by the entire grid in 2006..

Sample group *m* determined as follows:

20% of electricity generated in 2006	10,072,937	MWh

[34] ACM0002 does not specify from which year the 20% of generating capacity must be. Therefore, we chose to calculate 20% generating capacity from the most recent year, 2006, because it was the year with the highest electricity generation.

Quantity of electricity generated in 5 plants built most recently	1,810,724	MWh
Quantity of electricity generated in 6 plants built most recently	17,837,277	MWh
Therefore, the last 6 plants constructed are included in the BM calculation as plant #6 falls in part of 20% of electricity generated. This is according to the directions provided in ACM002.		

The BM is calculated as follows:

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} \cdot COEF_{i,m}}{\sum_{m} GEN_{m,y}}$$

Where:

$F_{i,m,y}$	Amount of fuel i consumed by relevant power sources *m* in years y	t
$COEF_{i,m,y}$	CO_2 emission coefficient of fuel i, taking into account the carbon content of the fuel and the percent oxidation of the fuel	tCO_2/t
$GEN_{m,y}$	Electricity delivered to the grid by source *m*	MWh

Power Stations (Power source*m*)	**Fuel[35] (Fuel *i*)**	**Fuel consumption (t/year) (Amount of fuel *i* consumed in year *y*)**			**Electricity generation (MWh/year) ($GEN_{j,y}$ – Electricity delivered to grid)**		
		2004	**2005**	**2006**	**2004**	**2005**	**2006**
Etgal (Askogen)	Diesel	21,828	23,975	23,006	101,508	111,767	112,162
Gezer	Diesel	41,826	109,174	120,752	147,170	396,267	443,678
Atarot	Diesel	959	4,486	4,552	2,760	13,700	13,730
Hagit	Diesel	144,867	200,377	221,789	748,798	1,041,372	1,100,033
Alon Tavor	Diesel	21,762	50,346	42,325	67,777	164,471	141,121
Ruthenberg	Coal	5,901,796	5,804,143	5,584,387	17,197,184	16,941,628	16,026,553
	HFO	--	19,717	4,607			
	Diesel	--	3,337	3,884			

	$COEF_{i,j,y}$ (tCO_2/t) (includes oxidation factor)	**Source**
Coal	2.8797	IPCC 1996
HFO	3.0811	
Diesel	3.1801	

Total electricity generation for 2004-2006 in 6 plants constructed most recently	54,771,679	MWh
Total emissions for 2004-2006 from 6	53,170,750	tCO_2/yr

[35] HFO refers to heavy (residual) fuel oil.

plants constructed most recently		
BM	0.971	tCO_2/ MWh

STEP 3. Calculate the baseline emission factor EFy as the weighted average of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$):

$$EF_y = w_{OM} \cdot EF_{OM,y} + w_{BM} \cdot EF_{BM,y}$$

AM0029 requires that the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$).

Combined Margin

BM	0.971*0.5	tCO_2/ MWh
OM	0.903*0.5	tCO_2/ MWh
CM	**0.937**	tCO_2/ MWh

Option 3: Emission Factor of the Technology Identified in the Baseline
The emission factor of the technology and fuel identified as the most likely baseline scenario under "Identification of the baseline scenario" is calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

$COEF_{BL}$	0.0946	tCO_2/ GJ	IPCC 2006 for coal
η_{BL}	35	%	Efficiency of coal plant (see section B.4)
--	3.6	GJ/MWh	
$EF_{BL,CO2}$	0.973	**tCO2/MWh**	

Summary of the emission factors calculated:

Option 1	Build Margin (BM)	0.971	tCO2/MWh
Option 2	***Combined Margin (CM)***	***0.937***	***tCO2/MWh***
Option 3	Technology identified as the baseline scenario	0.973	tCO2/MWh

According to the procedure for calculating the grid emission factor ($EF_{BL,CO2,y}$), the lowest emission factor of the BM, the CM and the technology identified in the baseline scenario should be used to determine the project's baseline emissions. The CM is the lowest value, at 0.937 tCO_2/ MWh.

Table 2: Data for Calculation of OM and BM

Power Stations (Power source *j*)	Owner	Year of Commission (by date)	Fuel[36] ($F_{i,j,y}$)	Fuel consumption (t/year)			Electricity generation (MWh/year)			CO2 emissions (tCO2e/year)		
				2004	2005	2006	2004	2005	2006	2004	2005	2006
Etgal (Askogen)	Private	1998	Diesel	21,828	23,975	23,006	101,508	111,767	112,162	69,415	76,243	73,161
Gezer	State	1997	Diesel	41,826	109,174	120,752	147,170	396,267	443,678	133,011	347,185	384,004
Atarot	State	1997	Diesel	959	4,486	4,552	2,760	13,700	13,730	3,050	14,267	14,476
Hagit	State	1994	Diesel	144,867	200,377	221,789	748,798	1,041,372	1,100,033	460,692	637,220	705,312
Alon Tavor	State	1991	Diesel	21,762	50,346	42,325	67,777	164,471	141,121	69,205	160,104	134,598
Ruthenberg	State	1990	Coal	5,901,796	5,804,143	5,584,387	17,197,184	16,941,628	16,026,553	16,995,384	16,785,534	16,107,888
			HFO	--	19,717	4,607						
			Diesel	--	3,337	3,884						
Tzafit	State	1990	Diesel	7,446	47,826	34,618	22,663	153,747	111,696	23,679	152,091	110,089
Ramat Hovav	State	1989	Diesel	98,062	155,554	173,494	485,795	748,460	880,617	311,847	494,677	551,729
Orot Rabin	State	1981	Coal	6,814,862	6,847,955	7,082,387	19,256,078	19,185,765	19,708,689	19,624,737	19,748,541	20,436,731
			HFO	6,778	10,585	--						
			Diesel	--	2,397	2,827						
Eilat	State	1980	Diesel	6,689	11,573	10,695	16,360	27,976	28,268	21,272	36,803	34,011
Eshkol	State	1977	HFO	309,000	115,627	118,169	5,598,000	6,446,086	8,287,476	3,031,321	3,203,532	3,646,991
			NG	823,000	1,126,863	1,299,220						
			Diesel	--	98	153						
Kinarot	State	1975	Diesel	1,990	3,551	1,670	5,067	8,699	4,208	6,329	11,291	5,311
Reading*)	State	1970	HFO	407,297	391,486	112,019	1,760,622	1,702,721	1,765,508	1,254,911	1,208,437	961,280
			Diesel	--	705	256						

[36] HFO refers to heavy (residual) fuel oil.

			NG	--	--	243,554						
Haifa	State	1961	HFO	369,397	343,485	417,449	1,576,328	1,430,464	1,738,940	1,138,138	1,066,211	1,288,791
			Diesel	--	2,487	818						
Totals							**46,986,110**	**48,373,122**	**50,364,685**	**43,142,992**	**43,942,136**	**44,454,373**
Total for the 3-year period, 2004-2006							**145,723,917**			**131,539,501**		

Baseline Selection and Additionality:

Sensitivity Analysis:

It can be seen from data provided by the Israeli Electric company[37] that the electricity tariff in Israel is set by the Public Utilities Authority taking into account following components:

Components of The tariff

1. Fuels.
2. Operation and maintenance services including consumer cost.
3. Capital services:
   - Depreciation.
   - Interest on debt in NIS linked to the CPI.
   - Interest on debt in foreign currencies linked to the Bank of Israel Basket currencies.
   - Working Capital Financing.
   - Fair rate of return on equity.
   - Foreign currency risk exposure.
4. Compensation for the delays in updating the tariff.
5. Purchases from the IPP's (Generation only).
6. Sectorial efficiency factor.
7. Pension surcharge.
8. Exogenous cost due to the past.

Actual data provide shows that fuel costs make up 51.3% of the electricity tariff:

[37] http://www.israel-electric.co.il/bin/ibp.jsp?ibpDispWhat=zone&ibpDisplay=view&ibpPage=IRRWPage&ibpDispWho=IRRTariff&ibpZone=IRRTariff&

THE TARIFF PER KWH SOLD

03/05/2007

AVERAGE TARIFF BREAKDOWN	TARIFF AS OF 03/05/2007 AVERAGE TARIFF (AGOROT/KWH)	WEIGHT %	PRICE/ INDEX
TOTAL OPERATION & MAINTENANCE	7.687	21.2%	109.4
CAPITAL SERVICES			
DEPRECIATION	6.531	18.0%	109.4
INTEREST ON DEBT IN NIS	1.806	5.0%	109.4
INTEREST ON DEBT IN FOREIGN CURRENCY	2.742	7.6%	4.812
RATE OF RETURN ON EQUITY	2.451	6.8%	109.4
FOREIGN CURRENCY EXPOSURE	(0.150)	-0.4%	
COMPENSATION FROM PREVIOUS TARIFF	0.000	0.0%	109.4
TOTAL CAPITAL SERVICES COSTS	13.381	36.9%	
COMPENSATION FOR DELAY OF UPDATING TARIFF	0.014	0.0%	
TOTAL OPERATION & CAPITAL COST	21.082	58.2%	
PERMANENT EFFICIENCY REDUCTION	(3.363)	-9.3%	
CONSUMER COSTS	(0.967)	-2.7%	109.4
TOTAL COSTS LESS EFFICIENCY	16.752	46.2%	
WORKING CAPITAL FINANCING & CONSUMER COSTS & FREE OF CHARGE ELECTRICITY REDUCTION	0.880	2.4%	
TOTAL OPERATION & CAPITAL COSTS LESS EFFICIENCY	17.632	48.7%	
FUELS			
COAL FOR RABIN POWER STATION	4.176	11.5%	12.09
COAL FOR RUTENBERG POWER STATION	3.483	9.6%	11.54
VERY LOW SULPHUR	0.997	2.8%	39.98
GAS OIL	7.347	20.3%	100.15
GAS	2.729	7.5%	-
TOTAL FUELS COST	18.732	51.7%	
WORKING CAPITAL FINANCING & COMPENSATION FOR CONTRACTION & CONSUMER COSTS	(0.134)	-0.4%	
TOTAL FUELS COST	18.598	51.3%	
TOTAL COSTS INCLUDING FUELS	36.230	100.0%	
PENSION SURCHARGE	0.000		
PURCHASES FROM IPP	0.176		109.4
TOTAL TARIFF	36.406		

Additionality: Tel Aviv Stock Exchange Information.

Data was taken from the official site of the Tel Aviv Stock Exchange[38]

Government Bonds Indices:

Date	Index Base Price	Closing Index Value	Overall Market Cap (NIS thousands)
31/12/2006	207.5	207.75	265390667
30/11/2006	206.55	206.62	267401968
31/10/2006	205.65	205.72	263809655
28/09/2006	203.34	203.4	258300676
31/08/2006	202.32	202.46	255337430
31/07/2006	201.6	201.74	255562959
29/06/2006	200.3	200.36	253865929
31/05/2006	200.71	200.68	254677237
30/04/2006	200.07	200.37	255232086
30/03/2006	198.26	198.35	254020131
28/02/2006	197.8	197.96	264376242
31/01/2006	198.58	198.55	264221355
29/12/2005	196.9	197.21	261541552
30/11/2005	197.59	197.26	260660048
31/10/2005	198.36	198.49	261039065
29/09/2005	198.76	199.03	267173948
31/08/2005	197.5	197.61	264177339
31/07/2005	195.41	195.35	261618774
30/06/2005	193.11	193.46	258721587
31/05/2005	193.85	193.81	256594406
28/04/2005	191.59	191.68	258878362
31/03/2005	190.07	190.37	257223358
28/02/2005	189.77	189.93	258680408
31/01/2005	188.34	188.41	255028083
30/12/2004	185.94	186.16	253026979
30/11/2004	184.33	184.3	249028673

[38] http://www.tase.co.il/TASEEng/

31/10/2004	182.94	183.29	246464101
28/09/2004	182.9	182.78	244781849
31/08/2004	181.4	181.43	241572283
29/07/2004	179.83	179.94	238428668
30/06/2004	179.3	179.55	238501174
31/05/2004	178.53	178.77	239786835
29/04/2004	176.88	177.09	237704341
31/03/2004	177.24	177.41	235091987
29/02/2004	175.33	175.51	233643070
29/01/2004	176.63	176.54	231880806
31/12/2003	176.41	176.62	229712315

Tel Aviv 100 Indices:

Date	Index Base Price	Index Opening Price	Closing Index Value High	High	Low Low	Overall Market Cap (NIS thousands)
31/12/2006	925.6	920.18	921.69	925.81	914.57	497245648
30/11/2006	936.82	940.09	936.13	941.98	933.5	498029485
31/10/2006	910.89	915.02	914.13	919.71	912.97	477934757
28/09/2006	837.23	847.14	846.09	847.68	844.84	450784613
31/08/2006	819.03	823.31	820	824.26	819.58	444155841
31/07/2006	802.48	813.23	815.47	816.99	811.16	439729050
29/06/2006	797.81	795.8	793.57	800.2	791.01	429016408
31/05/2006	875.99	865.39	868.87	872.75	863.74	474642876
30/04/2006	879.92	881.48	884.28	885.65	881.43	489546665
30/03/2006	844.9	844.16	835.78	848.68	833.08	475711374
28/02/2006	822.93	829.29	823.21	832.11	821.48	473980893
31/01/2006	851.32	856.3	844.41	861.76	841.65	483120060
29/12/2005	817.61	819.8	822.99	823.49	817.98	447805158
30/11/2005	791.06	789.21	790.55	793.1	787.89	425701826
31/10/2005	757.63	758.44	765.37	767.22	758.44	405407720
29/09/2005	749.2	760.16	753.59	760.16	751.42	392144349
31/08/2005	716.64	717.09	715.07	718.27	713.5	371683167
31/07/2005	696.16	691.72	688.39	692.8	687.67	358675554
30/06/2005	659.59	661.32	656.48	661.72	652.71	344391314

31/05/2005	699.47	699.83	699.3	702.02	696.84	365171217
28/04/2005	670.23	673.38	676.7	677.3	671.69	350107057
31/03/2005	660.72	665.26	664.64	667.08	663.58	346420853
28/02/2005	661.94	663.64	672.37	673.38	663.62	343649049
31/01/2005	657.69	658.73	658.39	660.49	656.57	334879035
30/12/2004	629.9	632.38	635.95	636.92	630.12	326603732
30/11/2004	591.37	589.6	589.41	590.54	584.65	302469781
31/10/2004	545.8	548.4	552.27	552.79	548.02	285162020
28/09/2004	562.18	560.53	558.97	561.29	557.2	287710264
31/08/2004	558.12	556.53	551.09	556.53	549.09	289502597
29/07/2004	571.36	568.88	570.87	571.21	568.86	297946634
30/06/2004	593.05	594.96	596.24	596.78	594.84	320086416
31/05/2004	567.67	568.47	569.87	570.62	567.63	307491533
29/04/2004	579.35	571.5	571.18	572.25	566.23	306396403
31/03/2004	562.3	565.52	566.07	567.81	563.88	298404138
29/02/2004	559.36	563.59	564.81	566	563.23	296703146
29/01/2004	561.15	551.99	554.31	555.78	550.07	288576071
31/12/2003	529.17	529.86	534.39	535.44	529.86	267792814

Annex 4

MONITORING INFORMATION

The project activity is only expected to be operational by 2011. Operation and maintenance procedures for the power plant will be developed to meet the power plant's scheduled date of operations.

The methodology specifies that the parameters that must be monitored for the calculation of project emissions are:

- Annual fuel(s) consumption in project activity;
- Net calorific value(s) of the fuel(s) used in the project activity;
- Fuel emission factor for each fuel used in the project activity.

Another important parameter that will be monitored is the electricity generated by the plant.
Baseline emissions will be monitored per the requirements in ACM0002 version 06.

The information below comes from Appendix 3 to the Natural Gas Purchase Agreement, which is dictated by regulations in the Host Country for natural gas. The agreement includes details on how natural gas consumption will be monitored.

Measurement Procedure – Natural Gas Purchase Agreement

INTRODUCTION
This specification covers the measurement of gas by turbine meters and multi-path ultrasonic flow meters as related to the installation, operation and calibration practices for determining volume.
More detailed information regarding these issues is given in document EEN-ESP-SPC-031 ”Specification Turbine Meter Runs” and EEN-ESP-SPC-035 “Specification Ultrasonic Gas Meter Run”.

This specification does not cover the equipment used in the determination of pressures, temperatures, densities and other variables that must be known for the accurate determination of measured gas quantities. These items are covered by following documents:

- EEN-ESJ-SPC-008 ”Functional Specification for Gas Analysis System”
- EEN-ESJ-SPC-015 ”Functional Specification for Volume Corrector”
- EEN-ESJ-SPC-001 ”Functional Specification for Field Instruments” and
- EEN-ESP-RQU-001 ”General Design Criteria”

APPLICABLE CODES AND STANDARDS
The following standards and publications form an integral part of this specification:

- AGA report no. 7 Measurement of Gas by Turbine Meters
- AGA report no. 8 Compressibility Factor of Natural Gas and Related Hydrocarbon Gases
- AGA report no. 9 Measurement of Gas by Multi-path Ultrasonic Meters
- ANSI B16.5 Pipe Line Flanges and Flanged Fittings;
- API Chapter 21.1 MPMS Flow Measurement Using Electronic Metering Systems
- EN 50014 Electrical apparatus for potential explosive atmosphere;
- EN 50020 Electrical apparatus for potentially explosive atmosphere "intrinsically safe";
- ISO 5208 Industrial Valves / Pressure Testing of Valves
- ISO 9951 Measurement of gas flow conduits-Turbine meters *)
- DIN EN 12261 Gas Meters – Turbine gas Meters *)
- OIML R32 Rotary Piston Gas Meters and Turbine Gas Meters*)
- OIML R6 General Provisions for Gas Volume Meters *)
- [DVGW G685]

[* Upon availability of specific standards for Ultrasonic Turbine Meters these guidelines shall be used analogously]

PRINCIPLES OF MEASUREMENT
Depending on the gas flow rate the fiscal metering shall be divided into three basic measuring principles:

Single line meter run with check device using turbine meters	-	For gas flow rates up to 15,000 Sm^3/h

Single line meter run using ultrasonic meter and turbine meter in series	-	For gas flow rates over 20,000 Sm^3/h
Either of above principles, as agreed by the Parties	-	For gas flow rates from 15,000 Sm^3/h to 20.000 Sm^3/h

Every meter run consists of the following components, depending on measuring principle:

- Measuring device for definition of flow rate (gas meter like turbine meter, ultrasonic meter)
- [Measuring device for definition of gas quality (Gas Chromatograph)]
- Switch device between working and reserve line
- Shut-off devices upstream and downstream (Ball valves)
- Check device for gas meter
- Control device
- Communication device
- Applicable number of metering runs
- Pulsation / Vibration absorber (flow straightening vanes)
- Electro technical devices
- Additional equipment

SINGLE LINE METER RUN WITH CHECK DEVICE
This measuring principle is applicable for gas flow rates up to 15.000 Sm^3/h.

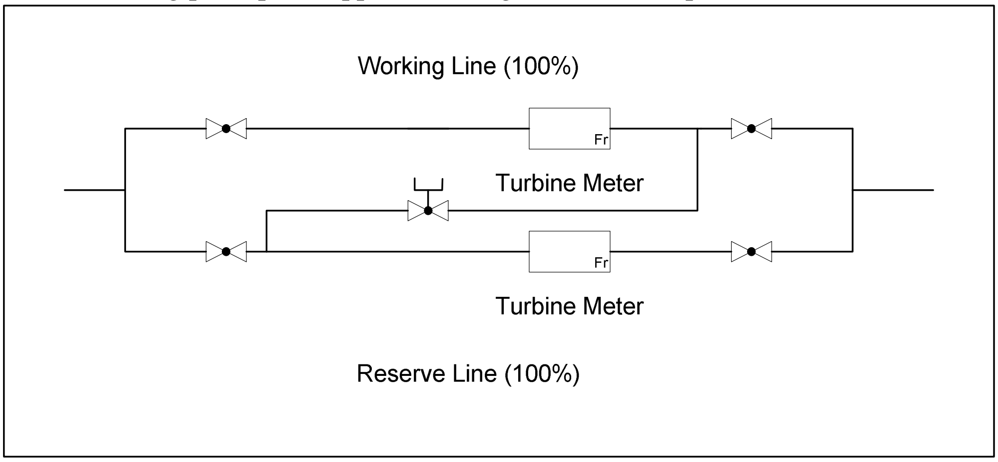

Figure 1: Single Line Meter Run with Check Device

SINGLE LINE METER RUN USING ULTRASONIC METER AND TURBINE METER IN SERIES
This measuring principle is applicable for gas flow rates over 20.000 Sm^3/h.

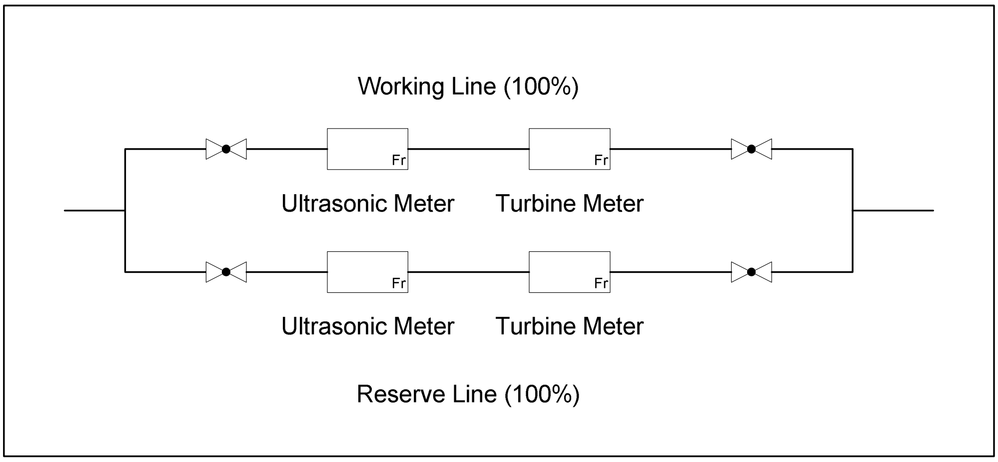

Figure 2: Single line meter run using ultrasonic meter and turbine meter in series

GENERAL REQUIREMENTS
The meters should be operated within the specific flow range and operating conditions to achieve the desired accuracy and normal life time.

The requirements of accuracy, safety, economy, efficiency, traceability and reliability shall be considered while designing the measurement system.
The metering runs shall be designed such that a single failure does not shut down the whole measurement.

ENGINEERING UNITS

Parameter	Units
density	kg / m^3
energy	MMBTU
mass	kg
pipe diameter	mm
pressure	bar or Pa
temperature	°C
velocity	m/s
viscosity, absolute dynamic	cP or Pa ·s
volume	Sm^3
volume flow rate	Sm^3 / h

Table 3: Engineering Units

CALIBRATION
An individual calibration of each meter shall be made prior to operation. The results of this calibration shall be available on request, together with a statement of conditions under which the calibration took place.

Meter Proving On Site
In the case of a single line meter run with check device, the meters shall be proven by serial operation at least annually. In case of a single line meter run using ultrasonic meter and turbine meter in series, the differential between the two meters shall be monitored continuously.

Calibration Intervals
The calibration intervals shall be as follows:

Component	Interval in years
Turbine Meter [G 4000 and G 6000] with oil pump	16
Turbine Meter for custody transfer with 1. $Q_{max} \geq 3000$ Sm^3/h 2. with installation of a reference meter 3. possibility to connect both meters in series 4. reference measurement during start-up and annual repetition of reference measurement	Unlimited (Note: all four conditions have to be fulfilled)
Calorific value measuring device	1
Flow computer	5
Additional devices except indicators and switch devices	5
Additional switch devices and switch over devices	unlimited

Table 4: Calibration Intervals

As far as the calibration approval defines a shorter period for calibration than given in Table 4: Calibration Intervals then the shorter interval has to be considered.

Maximum Permissible Error
The limit of maximum permissible error has to be defined as well for the single gas meter as for the complete measuring device.

Within the measuring device the systematic error of one gas meter should not be compensated by the contrarily systematic error of another gas meter.

Regarding measurement uncertainty analysis Technical Report ISO/TR 5168 has to be taken into consideration.

Especially the INGL-requirements listed below have to be followed:

Flow rate [m^3/h]	Maximum permission errors on initial verification	in service
$Q \leq 0.2 \times Q_{max}$	± 1%	± 2%
$Q > 0.2 \times Q_{max}$	± 0.5%	± 1%

Gas Quality Measurement – Natural Gas Purchase Agreement

1. GENERAL

INGL is operating the Transmission System in order to transport gas for the Shipper and Other Shippers from the Delivery Points to the Redelivery Points, without being the owner of the gas transported. In order to protect the Transmission System, the Shipper, and Other Shippers, INGL has established a gas quality specification, which is set out as Appendix 2 of this Agreement. This specification determines the maximum and minimum values of certain components and parameters of the gas. In order to maintain this quality, INGL shall carrying out quality measurements at certain points of the network

- At the Delivery Points (which may be carried out by the Upstream Operator on INGL's behalf)
- At the Redelivery Points

2. QUALITY MEASUREMENT AT THE DELIVERY POINTS

At the Delivery Points, two principle types of measurement will be carried out:

- Online measurement
- Offline measurement

2.1. __Online Measurement__

The Following properties will be measured online:

- Gas Composition (Calorific value) - measured with a Gas Chromatograph.
- Water Dew Point - measured by a moisture analyser
- Hydrocarbon Dewpoint - measured by a Hydrocarbon dewpoint analyser
- Hydrogen Sulphide - measured by a Sulphur analyser

2.2. __Offline Measurement__

The above online measurements shall be checked and verified by analytic investigation of the gas in a laboratory, initially at monthly intervals. The gas shall be taken by probes from dedicated points at each Delivery Points. Further, this quality measurement procedure will also be used to determine other components mentioned in Appendix 2, such as sulphur and sulphur compounds.

Upon conclusion by INGL, acting as a Reasonable and Prudent Operator, that the gas quality is stable, the interval may be extended to maximum one year.

3. QUALITY GAS MEASUREMENT AT THE REDELIVERY POINTS

Since the Natural Gas transported in the Transmission System may be from several sources, the gas composition (Calorific value) shall be measured at each Redelivery Point (unless agreed otherwise by the Parties). This measurement will be carried out by a gas chromatograph.

4. CALIBRATION AND VERIFICATION

Verification of the accuracy the above online measurement facilities will carried out by means of laboratory analysis of probes at annual intevals (or more frequently, as determined by INGL, acting as a Reasonable and Prudent Operator). In the event of discrepency between the online facilities and the laboratory analysis, the measurement equipment shall be recalibrated. The maximum interval between calibrations shall be determined in accordance with Statutory Requirements, or, if not applicable, in accordance with the recommendation of the manufacturer of the equipment.