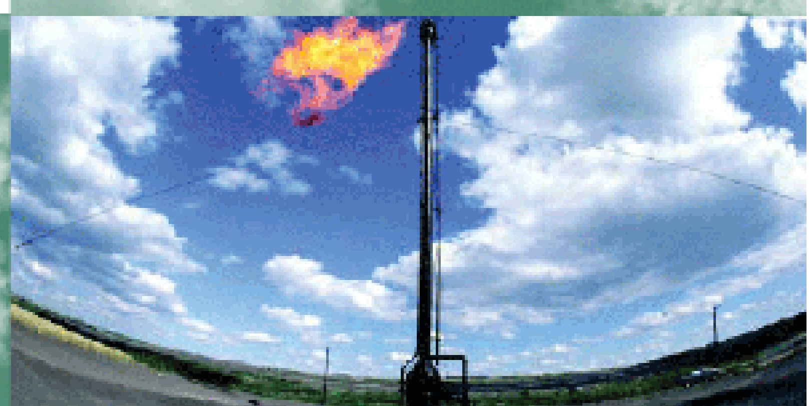
GLOBAL GAS FLARING REDUCTION

A PUBLIC-PRIVATE PARTNERSHIP

FLARED GAS UTILIZATION STRATEGY

Opportunities for Small-Scale Uses of Gas



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Opportunities for Small-Scale Uses of Gas

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This report is one of the outputs of the Global Initiative on Natural Gas Flaring Reduction, which aims to support national governments and the petroleum industry in their efforts to reduce flaring and venting of gas associated with the extraction of crude oil. The Initiative was transformed into the Global Gas Flaring Reduction Public-Private Partnership (GGFR) at the World Summit on Sustainable Development held in Johannesburg in August 2002. The aim of this report is to develop options for small-scale gas utilization and the impact that may provide toward poverty reduction. The first Steering Committee Meeting of the Partnership was held in December 2002, which agreed to a three-year work program and budget for the GGFR, which included the present work.

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Abbreviations and Acronyms

ADO	Automotive diesel oil
AEDE	Agence pour l'Énergie Domestique et l'Environnement
API	American Petroleum Institute
CEE	Central and Eastern Europe
CHP	Combined heat and power
CO_2	Carbon Dioxide
CONFENIAE	Confederación de Nacionalidades Indígenas de la Amazonía Ecuatoriana
DNH	National Directorate for Hydrocarbons
DOE	Department of Energy (USA)
EDC	Energy Development Corporation
EES	Empresa Eléctrica Sucumbios S.A.
EIA	Energy Information Administration (USA)
EIRR	Economic internal rate of return
ENH	Empresa Nacional de Hidrocarbonetos de Mocambique
ESMAP	Energy Sector Management Assistance Program
EU	European Union
FIRR	Financial internal rate of return
FSU	Former Soviet Union
GDP	Gross domestic product
GDP	Gross domestic product
GGFR	Global Gas Flaring Reduction Public-Private Partnership
GNI	Gross national income
GNI	Gross national income
GNP	Gross national product
HDPE	High density polyethylene
HFO	Heavy fuel oil
IEA	International Energy Agency
IMF	International Monetary Fund
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
Mogas	Motor gasoline
NPER	Net primary enrolment rates
NPV	Net present value
O&M	Operation and maintenance
OCP	Oleoducto de Crudo Pesado (Heavy crude oil pipeline)
OECD	Organization of Economic Cooperation and Development
PNG	Programme Nationale du Gaz (National Gas Program)
RFO	Residual heavy fuel oil
SEERAT	Société d'Étude et d'Exploitation de la Raffinerie du Tchad
SNI	Sistema Nacional Interconectado
SNT	Ecuador's national transmission system
SOTE	Trans-Ecuadorian Pipeline

STEE	Société Tchadienne d'Eau et d'Électricité
TFE	Total Fina Elf
TPES	Total Primary Energy Supply
UN	United Nations
US	United States
US$	U.S. Dollar
WBG	World Bank Group
WNSD	Wärtsilä NSD Power Development, Inc.

Units of Measure

B,b,G	Billion, giga (10^9)
BBBL	Billion barrels
BBOE	Billion barrels oil equivalent
BCF	Billion cubic feet
BL, bbl	Barrel, Barrels
bcm	Billion cubic meters
BOE	Barrels oil equivalent
BPD	Barrels of oil per day
CF, CFD	Cubic feet, cubic feet per day
GJ	Gigajoule
GW, GWh	Gigawatt, Gigawatt-hours
k	Thousand, kilo (10^3)
kcal	kilocalorie
km	kilometer
kV	kilovolt
kW, kWh	Kilowatt, kilowatt-hours
Mcal	Mega calorie
MM, M	Million, mega (10^6)
MMB	Million barrels
MMBOE	Million barrels oil equivalent
MMbtu	Million British thermal units
MMCFD	Million cubic feet per day
MMTOE	Million tons of oil equivalent
MW, MWh	Megawatt, Megawatt-hour
SCFD	Standard cubic feet per day
T,T	Trillion, tera (10^12)
t/d	tons per day
TCF	Trillion cubic feet
TJ	Terajoule
TOE	Tons oil equivalent

Conversions and Equivalences

Weight:

ton	1000 kg (also referred to as metric ton)

Volume:

American convention standard cubic meters and cubic feet are used throughout the report and are referred to as m^3 or Sm^3 and CF or SCF.

1 m^3	35.315 CF
1 CF	0.2832 m^3
1 BL	159 liters; 0.159 m^3
1 m^3	6.29 BBL

Energy Content (LHV)

	kcal/kg	**btu/kg**
Oil equivalent	10,000	39,690
Heavy Fuel Oil	9,750	38,690
Gas Oil, diesel oil	10,000	39,690
Jet Fuel	10,470	41,520
Kerosene	10,390	41,520
LPG	11,000	43,600
Fuelwood	3,000	11,940
Charcoal	7,000	27,860
Natural gas (per m^3)	8,500	33,740

Energy Equivalences

1 kWh = 0.86 Mcal = 3.6 MJ
1 MMbtu = 252 Mcal = 293 kWh = 1,055 MJ
1,000 m^3 natural gas = 0.85 TOE
1,000 kWh electricity = 0.11 TOE (final consumption)
1 ton wood = 0.3 TOE
1 ton charcoal = 0.7 TOE

Executive Summary

Background and Study Objectives

The World Bank Group (WBG) has launched a partnership on Natural Gas Flaring Reduction. Within this framework the World Bank has finalized a Report on Consultations with Stakeholders[1] which among suggested other uses also states that associated gas could be used in various small-scale applications.

The background for the present study on small-scale utilization of flared gas is the goal to achieve poverty alleviation by making more gas (and gas-fired power) available for use by the rural and urban poor and reducing the environmental and health impact of gas flaring in poor and often remote areas.

The main objective of this study is to assess the technical feasibility and economic viability of using flared gas in various applications ranging from rural electrification to commercial and industrial usage. Furthermore, two case studies, one in Chad and one in Ecuador, have been analyzed with the purpose of identifying viable pilot projects which can progress to a detailed feasibility and implementation phase subsequent to this study, which was concluded in 2002. In addition, the Vilankulu gas distribution project in Mozambique, which uses nonassociated gas, was examined 10 years into its existence for possible lessons learned.

Technology Options

The following four options have been identified and considered for using associated gas:

1. Power production at the oil field for transmission to existing power grid (medium-scale).
2. Power production at the oil field for electrification of nonelectrified rural area (small-scale).
3. Supply of piped gas to larger consumers, such as heat and power plants and industries (medium-scale).[2]
4. Liquefied petroleum gas production (LPG), alone or in combination with other means of use (small-scale).

Options 1 and 2 are most relevant for the subtropical and tropical climates which dominate most oil-producing developing countries. They can both be combined with option 4. These options will be used as the basis for the financial modeling in this report.

Findings

The study has identified a number of realistic options for the small-scale use of flare gas. The opportunities have been evaluated based on two cases studies examined in Chad and Ecuador,

[1] See Report on Consultations with Stakeholders, The World Bank, 2002.

[2] This solution will be the most suitable for cold places such as Siberia, Kazakhstan, and Northern China, where the associated gas might substitute oil in district heating plants.

the lessons learned from a nonassociated gas distribution project in Mozambique, and financial and economical modeling. This has led to the following main findings:

In general, the Chad and the Ecuador case studies both illustrate that small-scale/medium-scale use of flare gas can add important environmental, social, and wider developmental aspects to a developing country oil project without jeopardizing economics or financial viability. The feasible end-use options include power supply from generators established at the oil field and gas supply via pipeline to a load center for fuel substitution in power production and local industries.

The Vilankulo Gas Pilot Project in Mozambique (even though based on supply of nonassociated gas) illustrates clearly the potential for small-scale local uses of natural gas wherever a gas supply source is available. Overall, therefore, it should be possible to replicate this kind of project elsewhere, even though this is likely to require some involvement by the local government, as well as the focused delivery of appropriate technology and practical know how.

Economic and financial model analyses for initial screening purposes appear to indicate that flaring reduction is a win-win option in many cases. Subsidies are in general not needed—companies, governments, consumers, and the environment all stand to gain. The exceptions are:

- Where markets are far away (for a medium-size oil field it will be feasible to move the gas or power roughly 500 km in order to get to a market)
- Where gas deposits are small (model calculations indicate that gas utilization from oil fields with gas yields over 2,500–5,000 m^3 per day can be viable)
- Where prices are distorted by domestic fuel subsidies

The analysis also indicates that there is little economic difference between (a) transporting gas in pipelines to an industrial gas customer or an existing power plant and (b) power generation at the site and then transmission of power, by way of power lines to the load center.

Finally, the model suggests that LPG utilization becomes economically advantageous at LPG prices (world market) over US$300 per ton provided that the raw flare gas yields over 15 percent LPG or when the gas yield from the field is higher than 60,000 m^3 per day.

Since dry flare gas can be offered to industrial consumers at a price equivalent to or lower than the cheapest alternative, it opens up interesting perspectives. Experience from all over the world shows that once a cheap and stable fuel source like natural gas is available a number of industries will be attracted and the ensuing import substitution will give higher value added in the country.

Key Constraints for Small-Scale Gas Use

The following key constraints for small-scale gas utilization have been identified in the two case studies:

- State-owned oil and gas monopolies lack financial incentives to reduce flaring and to invest in alternative utilization options.
- National power markets are monopolized and poor buy-back conditions for electricity from independent power producers tend to prevent take-up of small-scale flare gas uses for power production.

Recommendations

To counter these constraints, the following measures are recommended:

- Among the regulatory and institutional barriers for small-scale flared gas use that would need to be addressed, one of the most important is the opening up of opportunities for private entities to take part in the production and distribution of gas and electricity.
- This work has highlighted the need to deal with LPG distribution at a strategic level. Since LPG production will be an integral part of many small-scale flare gas usage projects in developing countries, it will be necessary to investigate the framework for LPG distribution as part of a decision to produce LPG. Future LPG demand (local and regional) is a critical factor and the interrelation between government subsidy policy and LPG demand has to be scrutinized.
- Governments should be advised to focus on the following key requirements for the successful development of viable small-scale gas transport projects:
  - Availability of a wholesale-priced natural gas supply, that is, the gas should already be developed for the benefit of an anchor customer.
  - Access to gas transportation in major pipelines at the same prices as large users, that is, clearly regulated third-party access to major pipelines at official and published rates or at least with a possibility of negotiating a standard contract for gas transport.
  - Access to pipeline right of way for distribution pipelines at low cost, that is, clearly regulated third-party access to gas distribution networks.
  - Entrepeneurs' access to technology and expertise: Appropriate technology for the local situation and the local skills at reasonable costs—for instance by making state oil company knowledge available for this purpose.
  - Availability of financing for new small-scale projects including financing for investments in customer fuel conversion equipment.
  - Tax or other incentives to motivate small-scale customers to convert to gas.
- Capacity building in relation to the possibilities for small-scale gas utilization should be introduced in the countries targeted by the Global Gas Flaring Reduction Public-Private Partnership (GGFR) to facilitate partnerships between state-owned national oil companies and the private sector, taking as starting points the needs of local/regional entrepreneurs and the resources which state oil companies can make available to them; training in using software tools for market development could be provided at a relatively low cost.
- For the surveyed small-scale projects in Chad and Ecuador it is recommended that the next steps be taken toward their implementation. The first steps include followup studies to determine how the projects might best be structured institutionally and commercially, preparation of a detailed gas utilization strategy,

additional socioeconomic surveys to deal with pricing, subsidies, and the opportunities to achieve poverty alleviation as well as detailed project design.

1 Introduction

Despite efforts to curb gas flaring and venting, the issue remains a major problem, particularly in developing and transitional countries with significant oil production. Flaring and venting often constitute a waste of economically valuable resources and contribute significantly to global warming.

The main objective of this study is to assess the technical feasibility and economic viability of using associated gas in various applications ranging from rural electrification to commercial and industrial usage. A major deliverable of this study is the selection of two pilot projects which can progress to detailed feasibility studies and, if the projects are viable, implementation. One main selection factor for the pilot projects will be their poverty reduction potential.

This report gives an overview of the market opportunities for flared gas use and the corresponding impact on the environment and opportunities for sustainable development and poverty reduction. The report contains an initial set of project unit costs and a model for financial and economic analyses. In addition, the case study reports include the draft conceptual designs for the associated gas recovery systems.

As already mentioned, two countries were selected for case studies in order to identify two pilot projects for further analysis. The first case study selected is located in Chad where associated gas is to be transported to the capital, N'Djamena, for power production, LPG production, and industrial use. The second case study was identified in Ecuador where electrical power is to be produced on site and then transmitted to the local grid to replace diesel generated electrical power.

The report consists of a diagnostic part regarding markets for small-scale use, usage possibilities, and environmental impact. It also contains a toolbox which can be used for identification, evaluation, and design of flaring reduction projects. The toolbox consists of sections on basic characteristics of oil fields, requirements for gas treatment, the production of LPG, gas transmission and distribution, power generation and distribution, costing, and a model for economic/financial viability assessment. It is available on the Partnership's website at: http://www.worldbank.org/ogmc/ggfrsmallscale.htm.

2 Options for Small-Scale Use of Flared Gas

2.1 Potential Markets for Associated Gas

The Report on Consultations with Stakeholders concludes that international markets are the most important potential outlets for associated gas as local markets will be insufficient to absorb the quantities of gas flared, particularly in Africa and the Middle East.

This report also deals with the domestic market for associated gas stressing first the need for regulatory clarity and stability and, second, the benefits of preparing gas master plans. The report also indicates that associated gas could be used in various small-scale applications

The following sections will look into such small-scale applications and their technical and financial viability bearing in mind that the market for and viability of small-scale gas use is complicated in that often future large-scale use of associated gas (anchor customers) will often be one of the defining parameters for the economic and financial viability of small-scale projects.

2.2 Small-Scale Use Options

A number of associated gas usage possibilities exist with different requirements in terms of gas treatment and technical facilities. These usage options primarily relate to "real" small-scale use where the purpose is directly related to providing new energy options for households and small-scale industry. Such projects are local and will be located within a reasonable distance from the oil fields. Another type of relevant project could also be termed “medium-scale use” because the quantities involved tend to be bigger than in the projects mentioned above. In these small to medium-scale projects, gas is substituted for alternative fuels in power plants, district heating plants, or industries and may be used as a source of LPG (if the gas contains LPG in commercially viable quantities). These projects often have a regional nature and can involve crossborder cooperation. Both types of projects can fit into the overall objectives of this study, that is, to target the poorer segments of the population in countries where gas flaring is taking place.

An example of such a project is that LPG delivered to the urban middle-classes will do little to help alleviate poverty, while electricity is consumed by a far broader segment of the population than LPG. Unstable power supply (and in some countries high cost) is a major problem, leading to all kinds of inefficiencies. If cheap gas could make it possible to expand power distribution to previously unconnected households it would have a major poverty impact. Hence, using gas to make power supply cheaper for urban households can be a sustainable and poverty-oriented “small-scale” gas usage.

The following four options are identified and considered for associated gas use:

1. Electrical power production at the oil field for transmission to an existing grid (medium-scale).
2. Power production at the oil field for electrification of nonelectrified rural area (small-scale).

3. Piped gas supply of to larger consumers, such as district heating, power plants, and medium-scale industries.[3]

4. Liquefied petroleum gas (LPG) extraction from associated gas, alone or in combination with other means of usage (small-scale).

Options 1 and 2 are most relevant for the subtropical and tropical climates which predominate in most oil-producing developing countries. They can both be combined with option 4. These options will be used as the basis for the financial modeling later in this report.

[3] This solution will be the most suitable for cold places such as Siberia, Kazakhstan and Northern China, where the associated gas might replace oil in district heating plants.

3 Environmental Impact of Gas Flaring

3.1 Local Environmental and Health Impacts

Gas flaring is associated with the release of a large number of pollutants. Improper combustion, as indicated by smoke from the flare stack, contributes to increasing the hazardous chemicals released into the environment including volatile organic compounds. The substances include:

- More than 250 identified toxins, including carcinogens such as benzopyrene, benzene, carbon disulphide (CS_2), carbonyl sulphide (COS), and toluene
- Metals such as mercury, arsenic, and chromium
- Nitrogen oxides
- Sour gas with H_2S and SO_2

Most gas flaring reduction is in essence a question of changing the purpose of the combustion at the oil field from gas elimination (flaring) to gas use, (for example, power production), or of moving the combustion away from the field—normally to a load center where it will be combusted for industrial or power production purposes. The local environmental effects of flaring therefore depend on the efficiency and location of the combustion process and which type of fuel is replaced by gas use. In conclusion, the local effects are project specific and must be analyzed on a case-by-case basis.

3.2 Global Environmental Impacts

Beside constituting a waste of economically valuable resources, flaring and venting are also significant contributors to global warming. Reduced flaring implies reduced carbon dioxide (CO_2) emissions, the amount of which depends on whether the gas is reinjected or replaces other fossil fuels such as diesel or coal. This reduction in CO_2 not only benefits the country that achieves the emission reductions, but constitutes a contribution to global efforts to limit CO_2 emissions with the objective of preventing climate change. CO_2 emission reductions constitute a service to the global community by reducing the risk of damage to human health, water systems, agriculture, and fishing resulting from climate change. At the same time, Emissions Trading, Joint Implementation, and the Clean Development Mechanism under the Kyoto Protocol represent opportunities for the countries which restrict gas flaring to capture part of the global public benefits of emission reductions.

3.2.1 CO2 Emission from Gas Flaring

Based on the estimated annual amount of gas flared, the CO_2 emission from gas flaring has been calculated.

Table 3.1 Estimated Annual CO_2 Emissions from Flared Gas (2002 & 2001 figures)

Region	Gas Flared or Vented (Bm³)	Gas Flared or Vented (10^9 MJ)	CO_2 Emission from Flaring (million tons)
Africa	37	1221	72
Asia-Oceania	7-20	231-660	14-39
Europe	3	99	6
Former Soviet Union	17-32	561-1056	33-62
Central and South America	17	561	33
Middle East	16	528	31
North America	5-10	165-330	10-19
World total	102-135	3366-4455	199-262

Source: Report on Consultations with Stakeholders plus COWI calculations (1 m^3 = 33.0 MJ and 0.059 kg of CO_2 per MJ).

As can be seen from Table 3.1, the impact of gas flaring on global warming is considerable.[4]

3.2.2 Economic Assessment of Environmental Costs

In this section, the opportunity cost of flaring is estimated. To set the opportunity cost of CO_2 emissions' contribution to global warming, an estimate of the cost of the environmental damage caused by gas flaring is required. Alternatively, the point of departure can be the abatement costs of Annex-1 countries[5] that have emission reduction commitments and will consequently be looking for emission reduction options under the flexible mechanisms of the Kyoto Protocol. In either case, the valuation of opportunity costs requires knowledge of the emissions associated with the fuels that the gas will replace (unless the gas is reinjected).

Based on the CO_2 emission figures above, the economic cost of gas flaring with respect to CO_2 can be calculated. Other externalities than CO_2, such as reduction of SO_2 and NO_x emissions or local socioeconomic effects will normally not be quantified.

The benefits from flaring reduction are different from the flaring costs. They can be larger, the same, or smaller, but are likely smaller than the flaring costs. The flaring reduction benefits depend on which fuels flare gas replace (if any). If flare gas replaces imported gas, the benefits of flare reduction are equal to the costs of flaring. If flare gas replaces a renewable (hydro, sometimes wood) there is zero CO_2 reduction and hence zero benefit. If flare gas replaces oil, the benefit is the sum of the abated emissions from previous flaring plus the benefits of lower emissions from gas relative to oil.

If gas use leads to higher energy consumption (electric power to people who otherwise had nothing), there is zero environmental benefit (but there may be social and economic benefits).

[4] The Consultant's own estimate of total, global CO_2 emissions is about 7.5 billion tons. This means that gas flaring accounts for some 3 percent.

[5] Annex-1 countries are those that are committed to restrict CO_2 emissions.

3.2.3 CO_2 Emission Reduction

Economic costs

The economic cost of CO_2 emissions is either the cost of reducing or eliminating CO_2 emissions or the economic cost of the damage to the physical and biological environment caused by the CO_2 emission. In principle the lower of the two estimates should be used.

CO_2 abatement costs differ considerably depending on specific conditions in the relevant country and sector. In the ESMAP report: Increasing the Efficiency of Heating Systems in Central Europe and the Former Soviet Union, World Bank, August 2000, rough estimates for CO_2 reduction costs in Central and Eastern Europe (CEE), the Former Soviet Union (FSU), and the European Union (EU) are given:

Table 3.2 Cost of CO_2 emission in the CEE / FSU and the EU, US$ per ton

	Average Cost of CO_2 Emission Abatement (US$/ton)
CEE and FSU countries	10
EU countries	20–50

The EU countries will be obliged to carry out part of the reductions at "home," whereas other reductions can freely be acquired abroad, through the flexible Kyoto Mechanisms. The more CO_2 emission is reduced within the EU, the more expensive the overall reduction policy would be, and visa versa: The more that can be done in developing countries, where the reduction cost is lower than in the EU, the cheaper the reduction goal will be.

The European Commission has assumed that if emissions trading were introduced as a means to achieve the overall requirement of an 8 percent CO_2 reduction by 2010, the average reduction cost per ton of CO_2 would be € 33 (in 1999 €).[6] This is in line with the estimates made in the ESMAP study.

A low reduction cost of US$5–10 per ton CO_2 in line with above estimates for CEE/FSU and presumably corresponding to the level of some developing countries is estimated. However, when considering that reduction costs can be as high as US$100–200 per ton CO_2 in developed countries; such a low cost may be misleading. It is therefore suggested that a range of costs be used with an upper limit of US$20 per ton CO_2, as it could be argued that many of the investors in flaring reduction projects would be faced with much higher reduction costs if they were to make the same emission reduction in a developed country.

Tentatively valuing the avoided CO_2 emissions using economic costs of US$7–20 per ton, the total value of avoided CO_2 emissions from not flaring would be in the range of US$1,400 million to US$5,200 million as demonstrated in the table below, where values are calculated on a regional basis. The simplified approach of valuing avoided flaring on a 1:1 ton basis would represent the scenario of 100 percent reinjection in an oil reservoir. In reality, the gas used will

[6] The Economic Effects of EU-wide Industry-Level Emission Trading to Reduce Greenhouse Gases—Results from the PRIMES Energy Systems Model, May 2000, European Commission.

often replace a more carbon intensive fuel in which case it would be necessary to add the difference between the "baseline" emission using the original fuel and the emission from using gas.

It should be noted that the table is prepared based on sometimes incomplete and inconsistent data on flared gas quantities and flaring efficiency[7] as already mentioned in Chapter 3. As flaring efficiency improvement can greatly reduce methane emissions this should be the subject for more study.

Table 3.3 Estimated Economic Cost of CO_2 Emission from Flared Gas

Region	**CO_2 Emission from Flaring (million t)**	**Economic Cost at US$7/ton (US$ million)**	**Economic Cost at US$20/ton (US$ million)**
Africa	72	504	1,440
Asia-Oceania	14–39	98–73	280–780
Europe	6	42	120
Former Soviet Union	33–2	231–34	660–1,240
Central and South America	33	231	660
Middle East	31	217	620
North America	10–9	70–33	200–380
World Total	199–62	1,393–1,834	3,980–5,240

Source: Report on Consultations with Stakeholders plus COWI calculations (1 m³ = 33.0 MJ and 0.059 kg of CO_2 per MJ).

Financial costs

Current market prices (financial) for CO_2 emissions reductions are in the range of US$3–7 per ton of CO_2.[8] However, this market is still not very developed. For calculations it is suggested that a financial value in the range of US$0–5 per ton of CO_2 be used.

This carbon credit market would potentially be very attractive to some of the gas flaring nations in Africa, the FSU and Latin America. At a value of US$3 per ton of CO_2, the present flaring in these three regions represents potential annual revenues of US$216 million, US$99–186 million and US$99 million, respectively.

[7] The efficiency of the gas flaring, that is, the completeness of the gas combustion, is important because noncombusted methane released into the atmosphere is more than 20 times as potent a greenhouse gas than CO_2.

[8] Prototype Carbon Fund

4 Technical Aspects and Costs

In the following, a number of technical aspects and cost curves for gas treatment, LPG production, gas transport, and power generation are briefly presented. All cost curves presented below represent total costs including installation. However, operation and maintenance costs and fuel requirements are not included.

4.1 Gas Treatment

Associated gas will generally require treatment if it is to be utilized for different applications related to small-scale uses of associated gas. The table below lists the requirements for treatment of associated gas for power production at the oil field, transport of gas to consumers, and LPG production.

Table 4.1 Requirements for Treatment of Associated Gas

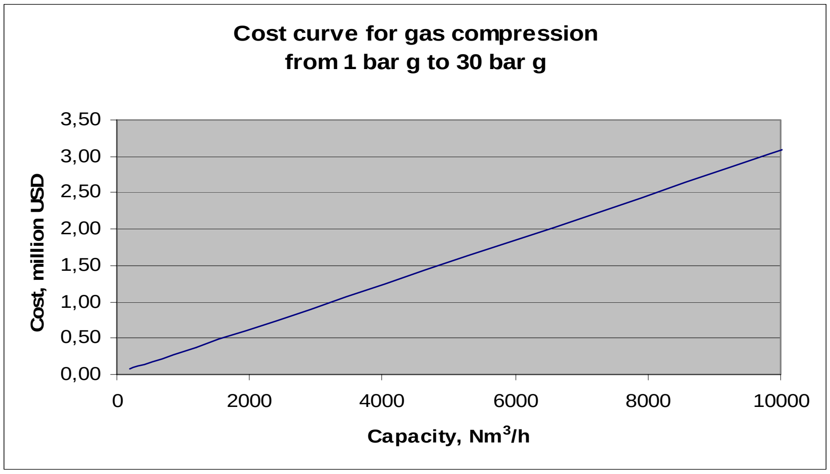
	Application of associated gas		
Gas treatment process/step	Power production at oil field	Transport of gas to consumers	Production of LPG
Compression	Required	Required	Required
Dehydration	Not required	Most likely required	Required
Chilling	Not required	Maybe required	Required
Sweetening	Not required	Maybe required	Maybe required

The different gas treatment processes are briefly described below.

4.1.1 Compression

After the mixture of oil and associated gas is brought to the surface, oil and associated gas are separated in one or more flash drums. In the flash drums, associated gas evaporates at atmospheric pressure. Gas compression is required when gas is to be used for power production or when transported in gas pipelines to consumers, or when it is to be processed in an LPG plant. For power production, gas would normally be compressed to 25–30 bar, while transmission in pipelines would normally require compression to a higher pressure. Liquids generated during gas compression are separated from the gas and recycled to the oil production.

Figure 4.1 Cost Curve for Gas Compression Used for Local Gas Supply in Power Production at Oil Field

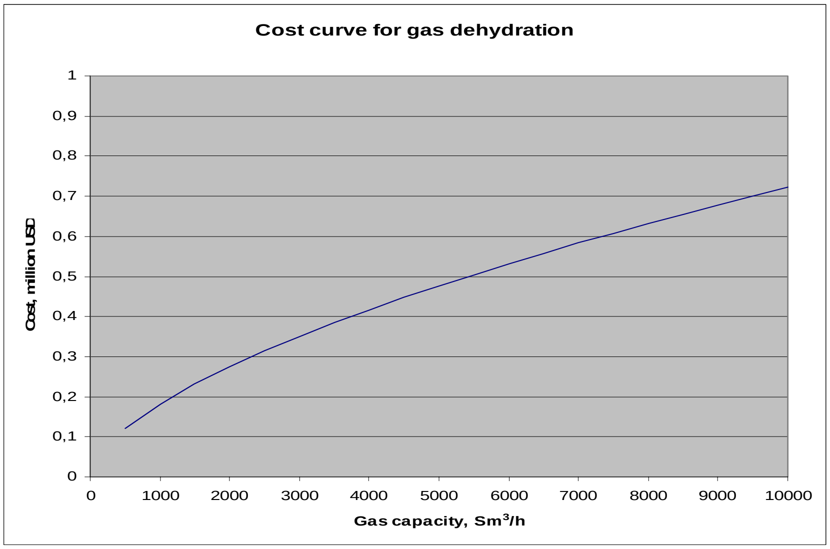


4.1.2 Dehydration

For LPG production dehydration is essential and, in most cases, associated gas must be dehydrated if it is to be transported in a pipeline. Dehydration is conducted in order to prevent hydrate formation which otherwise may build up at cold spots or where the pressure is high and block the gas flow in gas pipelines. In special cases, such as transportation of gas at low pressure in tropical regions, hydrates do not form. In such cases the gas does not necessarily have to be dehydrated prior to transportation in gas pipelines.

The formation of gas hydrates can be avoided by removing water vapor from the gas. At high flow rates, dehydration is almost always carried out by absorption of water in the hygroscopic liquid triethylene glycol (TEG). At lower flow rates, it is more cost efficient to use fixed bed, desiccant driers. The process only functions properly at high pressure, and it is thus placed after compression. The cost curve for dehydration at low flow rates is shown in the Figure 4.20.

Figure 4.2 Cost Curve for Gas Dehydration Used in Connection with Long Distance Transmission, Large Consumption, or Low Ambient Temperature

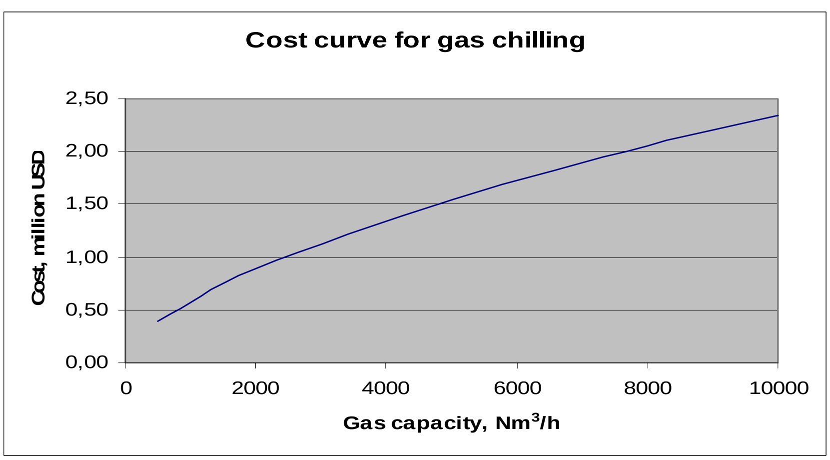


4.1.3 Chilling

Rich gas contains heavy hydrocarbons which will condense at elevated pressures as the gas cools. Gas condensates gathering in the pipeline lower the capacity of the pipeline. The liquids also compromise the safety in gas burners for the consumer. Heavy hydrocarbons are thus usually knocked-out before sending the gas to the transmission pipeline. Chilling will also be required for gas which is to be processed in an LPG plant.

Chilling of the associated gas to between -10^{o} and -20^{o} C, to remove the heavy hydrocarbons, is normally accomplished by means of a compression cooling system.

Figure 4.3 Cost Curve for Gas Chilling

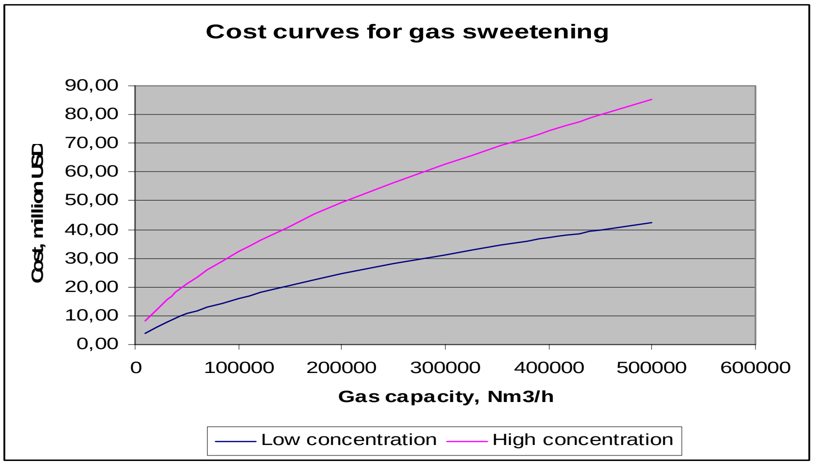


4.1.4 Sweetening

If the gas is sour, that is, containing hydrogen sulfide, H_2S, it cannot be sold to households and other small-scale users, partly because of the toxicity of the gas and partly because of the corrosive nature of the sulfur oxides that result from burning. If the gas is sour it can also cause corrosion in steel transmission pipelines and hydrogen sulfide itself may cause sulfide stress cracking.

The most common processes applied for gas sweetening are the amine absorption process, the molecular sieve process, and the iron-sponge process.

Figure 4.4 Cost Curves for Sour Gas Sweetening Before Use in Transmission Lines



4.2 LPG Production

Liquefied petroleum gas (LPG) is a very attractive way of using associated gas for the benefit of households and other users with a limited demand for energy. LPG is a mixture of hydrocarbons containing 3 to 4 carbon atoms (C_3 and C_4), for example, propane, butane, and isobutane.

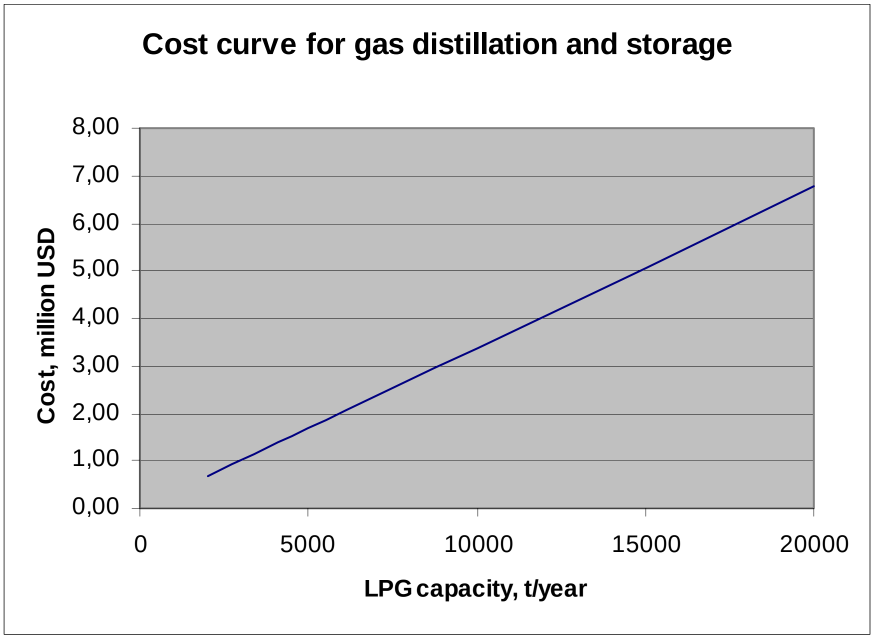
In order to recover LPG from associated gas, the latter has to be treated as necessary by the processes discussed in the preceding sections. Initially the associated gas must be compressed. If the gas is sour, it must in addition be sweetened, and finally, it is dehydrated and chilled.

LPG is produced from the liquid part of the associated gas which condenses during gas chilling. After gas chilling, liquids are separated from the gas in a separator vessel and then pumped to a distillation column. In the distillation column LPG is separated from the other fractions in the liquids and then transferred to pressurized buffer tanks from where it can be bottled and distributed.

The quantities of C_3 and C_4 present in associated gas vary considerably from one oil field to another, but it has been assumed that an average of 20 percent by weight of the associated gas can be used for LPG production. The cost of LPG production depends mostly on the quantity of LPG produced.

The cost curve in Figure 4.5 is based on the best estimate for the equipment needed. The costs include the total plant expenses including civil works, buildings, and structures needed, but the costs may vary from plant to plant depending on the external facilities needed and the local requirements. The curve does not contain the cost of bulk transport nor of bottling and distribution. However, for reference it can be mentioned that a 20 m^3 truck is estimated to cost around US$150,000.

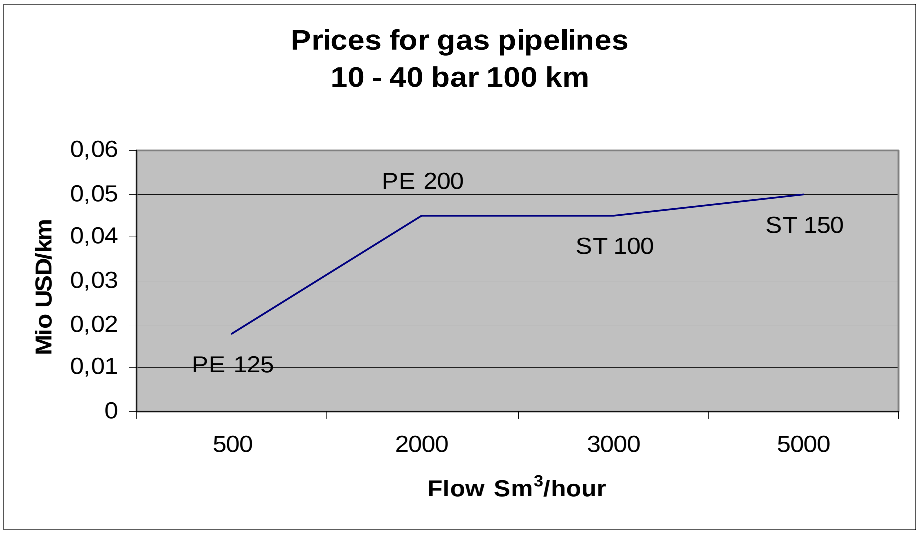
Figure 4.5 Cost Curve for Gas Distillation and Storage



4.3 Gas Transport

The transportation of relatively small quantities of dry, sweet associated gas from the oil field to the place of consumption requires that the gas is compressed to a pressure of 10–84 bar at the oil field and then fed into the gas pipeline. For pressures in excess of 10 bar, steel pipe with plastic lining and cathodic protection is usually used. For systems with pressures below 10 bar, high density polyethylene (HDPE) pipe is an attractive alternative to steel pipe.

Figure 4.6 Cost Curve for Gas Pipelines



The cost curve only relates to investment costs for pipes buried in the ground. The lower flows relate to PE pipes and the higher flows to steel pipes as noted in the graph, including diameters in mm. The costs are based on experience from a number of gas projects in Europe and Africa and do not include a compressor unit delivering the necessary inlet pressure. It should be noted that there are important economies of scale in gas transport. As the volume transported goes up, the cost per unit of energy transported decreases logarithmically.

4.4 Power Generation

Associated gas can be used for the production of power. If, in addition to a demand for power, there is also a demand for heat, combined heat and power technologies (CHP) can be used to produce both power and heat.

Electricity can be produced by generators driven by piston engines, gas turbines, or steam turbines. Small power producing units (250–5,000 kW) normally have overall efficiencies of 25–35 percent while larger power plants may have overall efficiencies in excess of 50 percent. For a combined production of heat and power at a larger plant, total energy efficiencies approaching 90 percent can be reached.

Figure 4.7 Cost Curve for Engine Installations

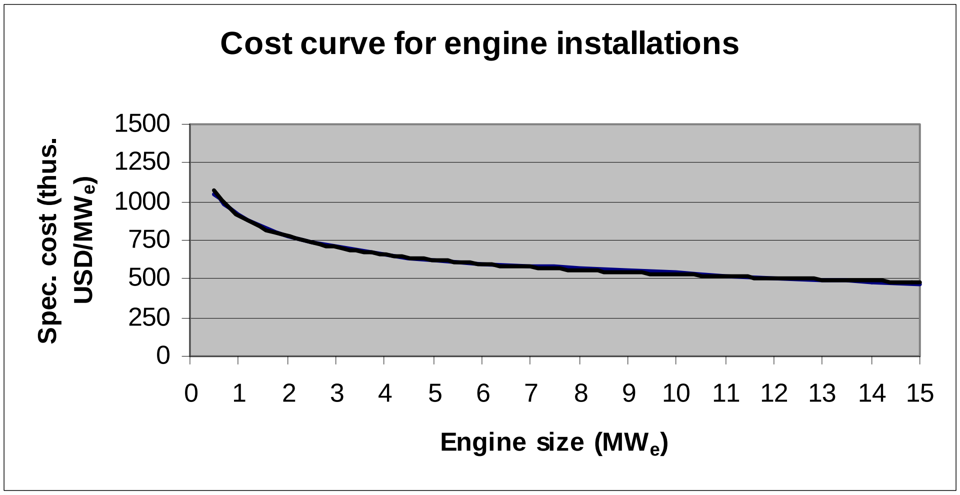
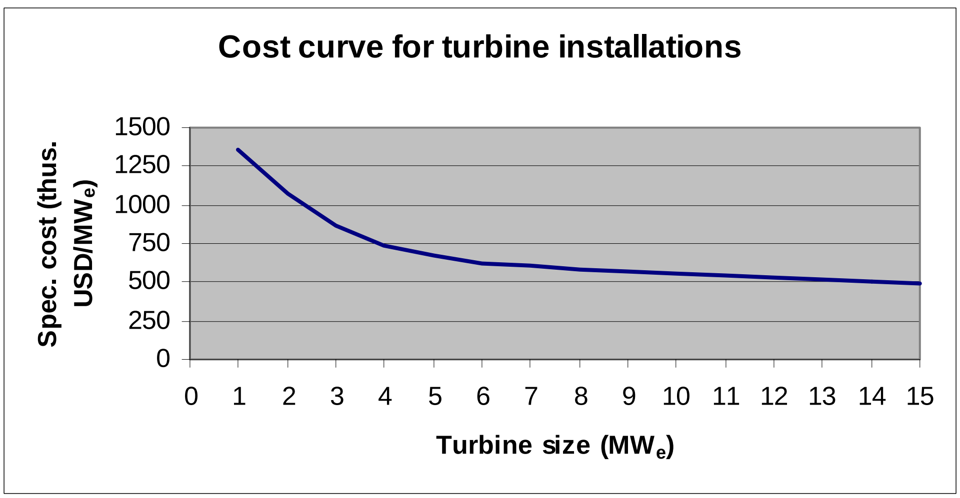


Figure 4.8 Cost Curve for Turbine Installations



5 Economic and Financial Modeling

The analysis of economic and financial benefits of flared gas usage brings the results of all other analyses into a surrounding framework and indicates the risk-rewarding profile and therefore the attractiveness of a specific project. The economic and financial modeling serves the intention of developing a "generic" model to be included in a workbook which is meant as a tool for project development of new small-scale gas flaring usage projects.

Each specific use of small-scale associated gas usage has specific costs and benefits caused by differences in technology and the number of the energy products replaced or involved. It is therefore not simple to develop a model/format for analysis of all project types. However, a generic model has been constructed to evaluate four different options for associated gas use. In Annex A and B, the results of using the methodology, structure, and assumptions regarding the economic and financial model development on the case studies in Chad and Ecuador are presented.[9]

From the outset the model presents a typical "model" oilfield with gas flaring—the data are adapted from the case studies in Chad and Ecuador presented in the following chapters. A user of the model will be able to substitute the data and assumptions from the "model" field to suit the specific circumstances of a real oilfield. However, the model can also be used for a parameter analysis that can give indications regarding the significance of parameters like field size, distance to load centers, fuel prices, and so forth on the financial and economic viability of gas use.

5.1 Parameter Analysis

The "model" oil field is assumed to have the following main characteristics:

Table 5.1 Model Oil Field

Field size	40,000	m^3 gas/day
Distance from load center	20	km
Maximum grid absorption	30,000	MWh/year
Power cost	75	US$/MWh
LPG cost	325	US$/ton
LPG share of gas	5	percent

With the data presented above, gas use can be calculated to be both economically and financially viable (that is, with economic internal rate of return higher than 12 percent and financial internal rate of return higher than 15 percent). Table 5.2 represents an example of the parameter analysis. The table presents part of the Economic Scenario Summary where the field's gas yield is varied from 2,500 m^3 per day to 60,000 m^3 per day. With the increasing economy of scale the results improve as the gas yield increases. It can be noted that in the analyzed constellation gas use from the field is viable all the way down to sizes in the range of 2,500 to 5,000 m^3 per day.

[9] A working model of the workbook is available on the GGFR webpage: www.worldbank.org/ggfr

Table 5.2 Example of Parameter Analysis Using the Economic Model

Economic Scenario Summary	**Field 1**	**Field 2**	**Field 3**	**Field 4**	**Field 5**
Changing Cells:					
Field size m^3 per day	2,500	5,000	20,000	40,000	60,000
Distance km	20	20	20	20	20
Grid absorption MWh	30,000	30,000	30,000	30,000	30,000
Power cost US$ per MWh	75	75	75	75	75
LPG cost US$ per ton	325	325	325	325	325
LPG share percent	5	5	5	5	5
Result Cells (Net Present Value in US$ million)					
Alt. 1 Power production at field	0.4	1.4	8.3	15.1	18.8
Alt. 2 Power production + LPG	-0.2	0.6	6.5	14.4	18.5
Alt. 3 Gas transport	1.1	2.6	12.1	18.3	20.5
Alt. 4 Gas transport + LPG	0.4	1.5	9.5	17.7	20.3

The other results of the parameter analysis are:

- There is little economic difference between transporting gas in pipelines to an industrial gas customer or an existing power plant on the one hand and power generation at the site and then transmission by way of power lines to the load center on the other. The choice of technical solution will then depend on whether or not there will be other applications for the gas than power production at the load center, for example, industrial end-use.
- The distance over which gas or power can be transported without offsetting the economic viability can be as high as 500 km if the cost of the fuel substituted is high, for example, imported diesel oil transported over a considerable distance; and if the gas yield is not too low, for example, more than 10,000 m^3 gas per day.
- Gas use is viable even when the only market for gas-based power is a grid with an absorption capacity as low as 2,500 MWh per year provided that the cost of the fuel substituted is high, for example, imported diesel oil transported over a considerable distance; and the transport distance for the gas is low, for example, less than 50 km.
- Gas use remains economically viable at a value of the produced power as low as US$25 per mWh (that is, 2.5 U.S. cents per kWh) given the gas yield is reasonably high (20,000–30,000 m^3 per day) and the transport distance is low (for example, less than 50 km).
- LPG use becomes economically advantageous at LPG world market prices over US$300 per ton provided that the content of LPG in the raw flare gas is over 15 percent and when the gas yield from the field is higher than 60,000 m^3 per day.

These results are purely indicative, and in each case all other parameters will need to be kept constant for the above conclusions to be valid.

6 Case Study I: Chad

6.1 Introduction

Despite efforts to curb gas flaring and venting, it remains a major problem, particularly in developing and transition countries with significant oil production. Flaring and venting often constitute a waste of economically valuable resources, and are also significant contributors to global warming. By supporting this work, the Bank would be responding to requests that it focus on the provision of global public goods. Gas flaring and venting, which is undertaken locally but whose main impact is global, has substantial crossborder externalities, which are not presently being taken into account. It can be reduced substantially and rapidly only through cooperation and collective action by developed and developing countries. The Bank would also be meeting its poverty alleviation goals by making more gas and gas-fired power available for use by the rural and urban poor and reducing the local environmental and health impact of gas flaring in poor and often remote areas.

This case study's main objective is to assess the technical and economic feasibility of using flared gas in various applications ranging from rural electrification to commercial and industrial usage. Market opportunities for flared gas use to support sustainable development and poverty reduction are emphasized. The definition of viable pilot projects, which could proceed to a detailed feasibility and implementation study, is inherent to this task. A main selection criterion of the pilot projects is their poverty reduction potential.

6.1.1 General

Chad covers 1,284,000 km^2, and is the fifth largest African country.[10] Being entirely landlocked in Central Africa makes access to the country very difficult. From north to south the distance is 1,800 km and from east to west approximately 1,000 km. The large size of the country gives it an asymmetrical climate; in the northern part, situated in the Sahelian zone it generally rains less than 10 days a year; and in the southern part, the climate is more tropical and it rains more than 100 days a year, which leads to frequent flooding.

Chad had approximately 8.1 million inhabitants in 2002 and the increase in population per year is approximately 2.7 percent, with average population density at 5.9 inhabitants/km^2. The average density conceals a very uneven distribution as only 3 percent of the population live in the northern part of the country and nearly half of the population is concentrated in the Sudanese-Guinean zone, which covers the southern part of the territory and only represents 10 percent of the national surface. This situation is caused by a massive migration attributable to successive droughts and civil wars that occurred mainly in the northern and central provinces of the country. Even though more than 70 percent of the population of Chad lives in a rural environment, the population increases rapidly in the urban areas: since 1984 N'Djamena has experienced a demographic increase of 7 percent per year.

Chad is one of the poorest countries in the world. Its per capita GNP (gross national product) was about US$251 in 2002. Agriculture generates about 40 percent of the gross domestic product and

[10] Number 20 in the world.

provides a meager livelihood for more than 80 percent of the population. Livestock in the Sahel and cotton in the Sudanese area are the main agricultural activities and Chad's main exports. Food production varies widely with seasonal conditions. Chad is also endowed with important natural resources. The industrial sector accounts for nearly 14 percent of GDP and is dominated by Coton-Tchad, the country's largest public sector company, which processes and exports cotton.

The economy suffers from some obvious disadvantages of landlocked countries: the nearest port is in Cameroon about 1,000 km away to the south and, with a vast and seasonally flooded territory, transport costs can be extremely high.[11] Nevertheless, economic performance has sharply improved since 1995, when Chad embarked on a structural adjustment program. Growth was 3.5 percent in 1996 and reached 10.0 percent in 2003, driven by a surge in agricultural production, a result of favorable weather and a bumper cotton crop encouraged by a substantial increase in farmers' prices.[12] Inflation, at 10 percent in 1995 and 1996, slowed to an estimated -1 percent in 2003. On the fiscal side, improved government revenue collection, while still weak, has allowed the resumption of critical spending, the elimination of all external arrears, and a reduction in the current account deficit to -44.8 percent of GNP in 2003. Spending on priority sectors (education, health, social affairs, and transport) have increased sharply, though, still constrained by Chad's current fiscal resources, they fall far short of needs. The economy remains vulnerable to such exogenous factors as changing weather patterns and fluctuations in commodity prices and exchange rates, but private investment is increasing, in part due to the development and exploitation of the country's oil resources.

Table 6.1 Main Macroeconomic and Development Indicators[13]

GNI, 2000 (US$, billions)	1.5
GNI per capita, 2000 (US$)	200
GDP, avg. annual growth rate, 1999–2000 (%)	0.6
GDP per capita, avg. annual growth rate, 1999–2000 (%)	-2.1
Population, 2002 (millions)	8.1
Population growth rate, 1980–2002 (%)	2.8
Infant mortality rate, 2002 (per 1,000 live births)	117
Under-five mortality rate, 2000 (per 1,000 live births)	188
Maternal mortality ratio, 1990-1998 (per 100,000 live births)	830
Life expectancy at birth, 2002 (years)	48
Male	47
Female	50
Access to improved water source, 2000 (% of population)	27
Energy use per capita, commercial, 1999 (kg of oil equivalent)	1,688

[11] *Source*: The World Bank home page for the Chad-Cameroon Petroleum Development and Pipeline Project, 2002, http://www.worldbank.org/afr/ccproj/.

[12] Growth is projected to increase by 37.9 percent in 2004 with the coming onstream of the Chad-Cameroon Pipeline.

[13] *Source*: 2002 and 2003, *World Development Indicators.*

Social indicators in Chad are among the lowest in sub-Saharan Africa. Life expectancy at birth is 48 years, compared to the regional average of 51. Vaccination coverage rates for, for example, measles, and diptheria, pertussis, and tetanus (DPT) were 28 and 19 percent in 1996, respectively. Net primary enrollment rates (NPER), though sharply increasing over the last three years, are still very low: the NPER for males and females were respectively 58 and 33 percent in 1997. The literacy rate is among the lowest in the world. Access to safe water is limited to about one fourth of the population, but it is as low as 7 percent in one of Chad's 14 administrative regions.

6.1.2 Forecast for Refined Petroleum Products

From the Doba oil field, production of oil for export through the Chad-Cameroon pipeline started in 2003. However, charcoal and wood still represent more than 80 percent of the national energy consumption; while oil represents less than 15 percent and electricity less than 2 percent.

Petroleum products will be imported from Cameroon and Nigeria until they can be substituted by refined petroleum products from the Sedigi oil field. Below the present consumption of petroleum products in Chad is estimated and a consumption forecast has been elaborated.

With the quality and the relatively small quantity of crude from Sedigi, asphalt and lube oils are not relevant to produce at the refinery, and statistics for imports hereof are therefore not of interest to this study. Apparently, heavy fuel oil has not been imported to Chad in the past—at least not in significant quantities, and consumption figures of HFO are thus not recorded.

6.1.2.1 Historical Data

The figures in Table 6.2 are based both on consumption figures and import statistics from customs.[14] The 1990, 1993, and 2000 columns are from statistics based on consumption, and the rest of the columns are based on import statistics.

Table 6.2 Market Statistics for Petroleum Products in Chad, m³ per year

	1990, consump.	**1993, consump.**	**1996, import**	**1997, import**	**1998, import**	**1999, import**	**2000, consump.**	**2001, import**
Butane/LPG	**138**	**200**	**ca. 300**	***486***	***547***	***609***	***671***	**811**
Gasoline (super)	21,000	28,725	20,860	23,424	22,972	23,783	22,670	20,326
+smuggling [15]	*3,150*[16]	*4,309*	*4,200*	*3,514*	*3,446*	*3,567*	*3,401*	*3,049*
Gasoline, total	**24,150**	**33,034**	**25,060**	**26,938**	**26,418**	**27,350**	**26,071**	**23,375**
Jet fuel	**43,526**	**21,630**	***28,020***	**29,711**	**33,084**	**36,259**	***34,319***	**32,000**
Kerosene	**5,000**	**3,625**	**10,652**	**12,975**	**15,052**	**17,463**	***19,769***	***22,068***
Diesel (Gasoil)	65,000	65,596	66,040	64,929	63,061	62,720	62,614	68,000
+ smuggling [15]	*9,750*	*9,839*	*9,906*	*9,739*	*9,459*	*9,408*	9,392	*10,200*
Diesel, total	**74,750**	**75,435**	**75,946**	**74,668**	**72,520**	**77,461**	**72,006**	**78,200**
Total	**147,564**	**133,924**	**139,978**	**144,777**	**147,621**	**159,142**	**152,836**	**156,453**

Source: *Ministère des Mines, de l'Énergie et du Pétrole, Direction du Pétrole: Statistics on fuel consumption in Chad*

[14] Data are from the Bureau Fiscalité Pétrolière. STEE was exempted from all taxes, so they are not included in the import statistics as prepared by the customs authorities.

[15] In 2000, it was suggested that 15 percent should be added to the 1999 official imports in order to account for smuggling and other types of fraud. This is assumed to be the case for the other years as well.

[16] Numbers estimated are in italics.

As can be seen from the table, no unambiguous trend in the development of consumption of petroleum products can be identified.

- Consumption of butane and LPG has increased from 138 to 811 m^3 per year from 1990 to 2001.
- Gasoline consumption increased in the beginning of the 1990s but a later decrease brought the present consumption back to the 1990 level. The ongoing smuggling probably means that the actual consumption is not well documented.
- Jet fuel consumption decreased drastically from 1990 to 1993 but increased from 1993 until 1999. Today it has decreased from the 1999 level.
- Consumption of kerosene increased enormously from 5,000 to 22,000 m^3 between 1990 and 2001.
- Diesel consumption has been more or less constant.

6.1.2.2 Future Consumption

No official consumption forecast of petroleum products is available. However, in the 1990s a market forecast was developed for a project to exploit the Sedigi oil field, and this forecast was made available by the Ministry of Petroleum.

The 1999 Forecast

The above mentioned project for the refinery notes the following consumption forecast.

Table 6.3 Total Chad Petroleum Product Demand[17], m^3 per year

	STEE fuel requirements [18]			Local Market Demand					
Year	**Diesel**	**Fuel oil**	**Total**	**LPG**	**MOGAS**	**Jet fuel**	**Diesel**	**Fuel oil**	**Total**
2000	12,500	15,300	27,800	3,700	31,500	15,100	61,300	2,700	114,300
2001	13,800	15,300	29,100	4,500	32,200	15,600	62,500	3,000	117,800
2002	7,500	22,900	30,400	5,500	33,100	16,200	64,300	2,000	121,100
2003	8,800	22,900	31,700	6,500	33,900	16,800	65,900	2,100	125,200
2004	10,300	22,900	33,200	7,300	34,700	17,200	67,500	2,200	128,900
2005	11,700	22,900	34,600	8,200	35,600	17,700	69,200	2,300	133,000
2006	13,500	22,900	36,400	8,600	36,500	18,100	70,900	2,500	136,700
2007	15,500	22,900	38,400	9,000	37,400	18,600	72,700	2,700	140,500
2008	17,800	22,900	40,700	9,500	38,300	19,100	74,500	3,000	144,400
2009	20,500	22,900	43,400	10,000	39,300	19,500	76,400	3,200	148,400
2010	23,400	22,900	46,300	10,500	40,200	20,000	78,300	3,500	152,500
2011	25,900	22,900	48,800	10,500	40,800	20,400	79,200	3,700	154,600
2012	28,600	22,900	51,500	10,500	41,400	20,800	80,100	3,900	156,700
2013	31,700	22,900	54,600	10,500	42,000	21,200	81,000	4,100	158,800
2014	35,000	22,900	57,900	10,500	42,700	21,600	82,000	4,300	161,000
2015	38,800	22,900	61,400	10,500	43,400	22,000	82,800	4,600	163,300

Updated Consumption Forecast for Petroleum Products

Based on the historical consumption data as shown in Table 6.2 this report has prepared an updated forecast of the market for petroleum products in Chad presented in Table 6.4. No forecast is made for heavy fuel oil (HFO) consumption since there is presently no market for HFO in Chad. Future HFO consumption will depend on the assumptions made in the scenarios regarding fuel for the power plant and industrial use presented in the economic and financial modeling.

The market forecast in Table 6.4 has been used as background for the evaluation of the Sedigi oil field in this report. It can be noted that according to estimates from TFE the LPG market has been estimated to develop much more slowly than foreseen by BEICIP.

[17] The forecast comes from the BEICIP study. When converting the above to refinery design it was assumed that the refinery would be onstream 330 days a year.

[18] The fuel forecast is based on total STEE demand for all STEE plants in Chad (N'Djamena, Moundu and Sahr).

Table 6.4 Forecast for LPG and Oil Products Consumption in Chad (in m^3/year)

m^3/year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
LPG	892	981	1,079	1,187	1,306	1,437	1,580	1,738
Gasoline	25,941	26,459	26,989	27,528	28,079	28,641	29,213	29,798
Kerosene	28,964	31,263	33,561	35,860	38,159	40,457	42,756	45,055
Diesel	47,191	46,673	46,143	45,604	45,053	44,491	43,919	43,334
m^3/year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
LPG	1,912	2,104	2,314	2,545	2,800	3,080	3,388	3,727
Gasoline	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Kerosene	47,354	49,652	51,951	54,250	56,548	58,847	61,146	63,445
Diesel	42,738	42,131	41,511	40,878	40,233	39,575	38,904	38,219

6.1.3 Power Production Forecast

6.1.3.1 Historical Data

Historical data for the power production in Chad were provided by STEE[19]:

Table 6.5 Approximate Historical Data for Total Power Production by STEE, GWh per year

Location	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
N'Djamena	73.86	72.20	70.94	73.54	73.03	76.22	78.36	77.12	69.61	81.02	77.20	89.99
Abéché	0.99	0.92	1.07	1.01	0.95	0.98	1.04	1.05	1.16	1.05	1.21	1.55
Moundou	5.05	5.18	5.50	5.59	5.24	5.44	5.71	5.02	4.18	4.07	3.71	4.88
Sarh	9.82	8.84	6.16	5.70	5.39	6.44	6.87	5.58	3.47	3.19	4.14	5.34
Faya	–	–	0.077	0.098	0.111	0.105	0.130	0.105	0.135	0.103	0.105	0.105
Bongor	–	–	–	–	–	–	0.024	0.041	0.040	0.049	0.071	0.071
Total	**89.72**	**87.14**	**83.74**	**85.94**	**84.72**	**89.18**	**92.13**	**88.93**	**78.57**	**89.48**	**86.44**	**101.94**

The table is based on the following measured, specific fuel consumptions in 2001:

N'Djamena	242.1 g/kWh
Abéché	298.3 g/kWh
Moundou	297.4 g/kWh
Sarh	292.2 g/kWh

Assuming a diesel density of 845 kg/t, the diesel consumption by STEE has been estimated in Table 6.6.

[19] The historical data from STEE have not been verified by the new management. The data from 2001 are exact.

Table 6.6 Estimate of Historical Diesel Consumption Figure by STEE

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
t/y	22,548	21,878	20,952	21,462	21,129	22,275	23,031	22,150	19,506	22,115	21,415	25,312
m^3/year	26,527	25,738	24,649	25,249	24,858	26,206	27,096	26,059	22,949	26,017	25,194	29,778

This set of data constitutes the most reliable source of information on Chad's consumption in the past.

6.1.3.2 Future Consumption

The STEE has recently established a well-qualified forecast for the coming decade. The forecast is split in two: N'Djamena and secondary towns. It has been reviewed by the Bank as the basis for future development supported by credits from the Bank. With this assistance, the old machines in the center of N'Djamena will be replaced with three diesel engines with a total power generating capacity of 15 MW. At the earliest in 2005 three gas turbines may also be installed with a total power generating capacity of 26 MW. Once the new diesel engines are installed, the HFO needed for running them will be purchased on the international market.

The diesel engines will be capable of burning any fuel from associated gas to heavy fuel oil, as well as crude oil from the Sedigi field. The gas turbines will be capable of burning associated gas as well as almost any distillate from the refinery as well as crude from Sedigi.

The smaller secondary towns will have to continue on diesel. This is why in the forecasts a distinction must be made between N'Djamena and the diesel-engine driven generators in the other towns in the country. As part of the development program supported by the Bank, the following new diesel engine driven installations have also been foreseen:

Moundou	2 x 1.5 MW in 2003
Sarh	2 x 1.5 MW in 2005

The demand forecast presented by STEE is developed for the purpose of a proposed Bank credit for the Critical Electricity and Water Services Rehabilitation Project.

The details of the forecast are shown in Tables 6.7 and 6.8. The specific consumption of the gas turbines has been assumed to be 0.300 m^3/kWh of normal, lean natural gas that results from processing of associated gas from the Sedigi field. This has been the basis for the consumption figures calculated in the table below. In case these engines are running on diesel, the forecast consumption has been calculated as well. And finally, it should be remembered, that the refinery would only be in operation for nine-tenths of the time caused by shutdowns for maintenance, meaning that 36 days a year the gas turbines must operate on another fuel. Heavy fuel oil or crude appear to be the least expensive choices for this. In order to avoid flaring, a storage tank for either of these two fuels must be available for the refinery shutdown period. It should be noted, that the reduction in the quantity of fuel consumed in the first years is attributable to an increase in the system efficiency.

When comparing the forecasted peak load and the installed gas turbine capacity, it can be seen that all along, the gas turbines will suffice to cover the expected peak load. Therefore, it may be assumed that all the power generation may be based on associated gas.

For the consumption of the secondary cities, the generator sets will be using diesel. The specific consumption, however, depends mostly on whether the machines are new or old. Therefore the calculation of the expected fuel consumption requires that the forecast power production be split on secondary cities. The percentage of the total power production for the secondary cities in 2001 is shown below. This split has been used for the future production forecast as well.

Moundou	40.85%
Sarh	44.70%, and
Other cities	14.45 % (Abéché, Faya, and Bongor)

Table 6.7 STEE Forecast of Power Production and Fuel Consumption for N'Djamena

Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Production, GWh/year	93.53	97.69	105.15	110.26	116.92	124.58	132.45	141.98	151.47
Peak load (MW)	21.5	22.4	24.2	25.4	26.9	28.5	30.2	32.3	34.5
3 new diesel engines	15	15	15	15	15	15	15	15	15
3 new gas turbines		26	26	26	26	26	26	26	26
1 new gas turbine							8.6	8.6	8.6
Total gas turbines (MW)		26	26	26	26	26	34.6	34.6	34.6
Potential max. gas consumption, $10^6 m^3/y$		26.4	28.4	29.8	31.6	33.6	35.8	38.3	40.9
Potential max. gas consumption, t/year		31,916	34,353	36,023	38,198	40,701	43,272	46,386	49,486
Potential min. HFO consumption, t/year		3,546	3,817	4,003	4,244	4,522	4,808	5,154	5,498
Potential diesel consumption in gas turbines, m^3/year		23,122	24,888	26,097	27,673	29,486	31,349	33,605	35,851

Table 6.8 STEE Forecast for Other Cities' Power Production and Fuel Consumption

Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Power production, GWH/year									
Moundou	4.95	5.19	5.54	5.77	6.08	6.45	6.83	7.31	7.80
Sarh	5.41	5.68	6.06	6.32	6.66	7.05	7.47	8.00	8.54
Abéché, Faya & Bongor	1.75	1.84	1.96	2.04	2.15	2.28	2.42	2.59	2.76
Other cities, Total	12.11	12.70	13.56	14.13	14.89	15.78	16.72	17.90	19.10
Diesel consumption, t/year									
Moundou	989	1,038	1,108	1,154	1,217	1,289	1,366	1,462	1,560
Sarh	1,597	1,135	1,212	1,263	1,331	1,411	1,495	1,600	1,708
Abéché, Faya & Bongor	516	541	578	602	635	673	713	763	814
Other cities, Total	3,102	2,714	2,898	3,020	3,182	3,373	3,574	3,826	4,082

6.2 Review of Alternative Gas Use Scenarios

The concept for the refinery at Farcha and the development of the Sedigi field as presently conceived by the government does not leave room for other gas usage than the small quantities required for power generation at the field and fuel at the refinery. Presently, the rest of the gas is thus planned to be flared.

Three alternative scenarios for associated gas use have been identified. They are contrasted with a baseline Scenario 0 which assumes that all associated gas is flared at Sedigi, refined products are sold locally, HFO is sold to the rehabilitated STEE power plant, and surplus gasoline is exported (for example, to Cameroon).

Scenario 1: Gas-based power production in N'Djamena

The most obvious option for use of the gas is to convert the STEE power plant from oil to gas in connection with the upcoming upgrading of its production facilities. The consumption forecast for this option is described in Section 6.1.3.

Scenario 2: Industrial gas use

Scenario 2 consists of Scenario 1 plus the supply of gas to an industrial site (a future brick works). Industrial plants could use the Sedigi gas either through a direct pipeline connection to the gas transmission line from Sedigi to the new Farcha Power plant or through an LPG supply. Whereas it is uncertain whether any of the existing industrial plants will be interested in converting to gas use, there seems to be a good case for establishing one or two brickworks using gas. Thus, the best option for using gas for industrial purposes is to reestablish one or two large brickworks in or around N'Djamena.

As an example the Setuba Brickworks was established in 1987 some 15 km from the center of N'Djamena close to the Chari River. The owners are now thinking about rehabilitating the brickworks, which is said to have had an annual capacity of 30 million bricks and a turnover of 1 billion FCFA in late 1986. An enormous amount of wood was used to burn the bricks at the time, and the rehabilitation is contingent upon having an alternative fuel (for example, gas) available.

It is estimated by the AEDE that presently, small and primitive brickworks use the equivalent of 29 million kg of wood to produce 45 million bricks for the N'Djamena area. This represents 17 percent of the wood consumption in N'Djamena.

For the longer term there may also be options to supply gas for a new dairy operation and for commercial refrigeration. However, the practical feasibility of such options will probably not be relevant to explore before a gas supply is established and there is a clear pricing policy for industrial gas supply. The interesting issue here is that the presence of gas (and residual oil/HFO from the refinery) may attract new operations (for example, there has been talk of a cement plant).

Supplying most of the present large electricity or LPG consumers with piped natural gas could also be considered. However, as for the soda bottling plant and any other existing industry using power today the perspective of changing technology in order to substitute gas for electricity will only move gas use from the STEE plant to the industrial plant, which in itself is of little importance for energy supply or gas use. The same argument applies to the possibility to substitute LPG use with dry gas or piped LPG. Also in this case it will be of little consequence to the gas demand or the economics of gas supply.

Scenario 3: LPG production

Scenario 3 consists of Scenario 2 plus LPG production at the new refinery in Farcha to cover the local demand and to sell the surplus LPG in regional markets. The idea behind this option is to substitute imported LPG with local production at the Farcha refinery based on the associated gas from Sedigi. As gas is currently imported from LPG facilities in Cameroon, it would not only mean an opportunity to cut costs but also to secure supplies.

6.2.1 Gas Demand

The estimation of future gas consumption may be summarized as follows:

Table 6.9 Forecast of Total Market for Dry Natural Gas (in t/year) in Chad

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013
Maximum gas, STEE	31,916	34,353	36,023	38,198	40,701	43,272	46,386	49,486	52,950
Farcha industrial park	2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189
Total gas	34,861	37,328	39,027	41,233	43,766	46,368	49,512	52,644	56,139

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Maximum gas, STEE	56,657	60,623	64,866	69,407	74,265	79,464	85,026	90,978	97,347
Farcha industrial park	3,221	3,253	32,86	3,319	3,352	3,385	3,419	3,453	3,488
Total gas	59,878	63,876	68,152	72,725	77,617	82,849	88,446	94,432	100,835

The associated gas actually produced at the well also contains LPG components; this is why the total production of associated gas at the well will be higher than the above figures for dry gas. The LPG is assumed to be sold on the regional market and does not impose any constraint on this no-flaring case.

6.2.2 Gas Use Ranges

Depending on the above possibilities for gas use, the percentages of associated gas which can be used will vary. To evaluate the financial and economic viability of the Sedigi field two different cases have been considered.

In the first case (Case 1) no gas is flared (in the most far-reaching scenario) and the oil production is reduced to the level required to achieve this goal of no flaring. (Iterations have shown that this is achieved at 2,200 bpd if there is no gas use for site installations and 2,400 bpd if gas is used for the onsite installations at Sedigi.)

In the second case (Case 2) the refinery is assumed to have a throughput reflecting the demand for petroleum products in Chad even though this entails some flaring. This gives a case with a refinery design, based on an earlier nonpublic evaluation, of 3,000 bpd but omitting jet fuel production. Taking into account the need for a higher average throughput to compensate for the one-tenth of the year where the refinery will be out of operation this will correspond to 3,300 bpd if there is no gas use for site installations and 3,500 bpd if gas is used for the onsite installations at Sedigi.

The two cases will be described further in the sections below. The starting point for both cases is the present situation in which:

- The 6-inch oil pipeline from Sedigi is almost completed.
- The field facilities at Sedigi are under construction including the necessary modification.
- There is no refinery, the few tanks that are partly finished by Concorp may serve for whichever development is coming later, but the process of establishing the refinery has come to a stop at present.

Therefore any investment that is required for equipment other than the 6-inch pipe, the basic field facilities, and the few tanks in Farcha will have to be considered as new investments under the two main cases described above.

6.3 Economic and Financial Considerations

6.3.1 Cost of Components for Gas Use

6.3.1.1 Gas Treatment at Sedigi

For all three scenarios, the following facilities, with a design capacity for 180 million Sm^3/year or approx. 25,000 Sm^3/hour, must be installed at Sedigi:

- Compressor station for compression from 1/8/19 bar and up to 140 bar
- Dehydration facilities
- Six-inch gas pipeline[20]

Installation of onsite facilities for site power (roughly estimated at 6 MW) and gas compression using flare gas is assumed but since this holds for all scenarios, the resulting investment has not been included in the present calculations (since only marginal investments to facilitate gas utilization need to be included). Such facilities are estimated totally to cost US$34.0 million, with approximately US$25.0 million for the gas pipeline and US$9.0 million for the compressor station and dehydration facilities.

6.3.2 Facilities at N'Djamena

Upon arrival to Farcha, the gas shall be heated and depressurized in different steps with condensates going to the refinery and a local 7 bar supply line to the intended industrial park and the rest going to the new STEE facility at Farcha.

[20] It should be noted that an 8-inch pipeline might be a better choice for this project. It would lower compressor fuel requirements (lower pressure required to move the gas), would not result in a very significant cost increase. (thinner wall pipe can be used at the lower pressure involved), and it would allow for some low-cost expansion of the gas industry if additional reserves are discovered in Northern Chad.

The approximate investments for these facilities are in all three production cases:

- Pressure reduction station for 25,000 Sm^3/hour with short-supply pipe to STEE, approximately US$1.2 million
- Pressure reduction station for 14,000 Sm^3/day, approximately US$0.8 million

The total cost for facilities in N'Djamena is thus US$2.0 million.

6.3.2.1 Refinery

The cost and equipment needed for the refinery is based on an earlier design. For each production case the investment costs have been estimated based on scaling from the costs in Case 2.

The two cases result in two sizes of the refinery.

- In Case 1, the estimated investment required for a 2,400 bpd refinery is US$78.1 million.
- In Case 2, the estimated investment required for a 3,500 bpd refinery is US$98.0 million.

6.3.2.2 STEE Gas Usage

If STEE uses the gas for power production, investment is needed in gas turbines with 35 MW capacity and connection to a gas supply, assuming a price of US$1.0 million per MW (and that the cost of connection to the gas supply will be negligible and offset by the improved efficiency), for a total of US$35.0 million. Correspondingly the investment at the power plant if HFO is to be used is a diesel capacity of 35 MW, US$1.0 million per MW, for a total of US$35.0 million.

6.3.2.3 Gas for Industrial Purposes

For gas to be supplied to industrial areas the following investments are needed:

- A 7 bar, 10 km pipeline with meters estimated at US$0.3 million
- Connection to the gas system estimated at US$0.02 million

The total investment in equipment for gas use at the brick factory is thus US$0.32 million.

LPG to the Local Market & Export

Investments in equipment for LPG collection including 15 storage tanks of 20 m^3 for export, unit price US$350,000, total investment US$5.25 million are needed. The total investment needed to supply LPG to local distributors and for export is thus US$5.25 million.

Total Investment

Based on the above, Table 6.10 summarizes the investment costs in each of the two production cases.

Table 6.10 Investment costs, US$ million

Investment Cost	Case 1 minimized flaring	Case 2 following demand
Production capacity	2,400 bpd	3,500 bpd
Wellhead - oil	sunk cost	sunk cost
Oil pipeline	sunk cost	sunk cost
Refinery	78.1	98.0
Power plant - STEE - diesel engines Sc.0	35.0	35.0
Scenario 0	113.1	133.0
Well head - additional gas facilities	9.0	9.0
Gas pipeline to N'Djamena	25.0	25.0
Additional gas facilities at refinery	2.0	2.0
Scenario 1	149.1	169.0
Brick industry (Gas)	0.3	0.3
Scenario 2	149.5	169.3
LPG to local market and export	5.3	5.3
Scenario 3	154.7	174.6

6.3.3 Analytical Method

Two types of analysis have been made:

1. An *Economic Cost Benefit Analysis* showing the project economy from society's viewpoint and based on assessment of benefits and project cost. Economic prices exclude taxes and subsidies. Cost and benefits will include nonpriced impact such as environment, balance of payment impact, and employment where relevant.
2. A *Financial Project Analysis* looks at the project from the project owner's perspective. Financial calculations are based on out-of-pocket prices, including taxes and subsidies. The financial analyses of the present project assumes that a state-owned company will be set up to construct and manage the oil production, transportation, and refining, and that this company sells the refined product, the gas and LPG at market prices (substitution prices) to the endusers (STEE, brick factory, and distributors of petroleum products). The presented financial project analysis is not a full-scale cash-flow analysis, but only looks at the marginal income and project costs.

The financial viability of gas use for power production and industrial end-use is checked by using the cost of the best scenario as the base case against which the marginal financial project analysis is carried out. This way the power plant and the industrial gas users will be financially neutral.

6.3.3.1 Project Boundary

The "making use of flared natural gas" project is regarded as incremental to an existing oil development project, and only incremental cost and benefits resulting from making flared gas useful need to be considered. However, as the Sedigi oil project was not yet realized at the time of writing, the total project was considered.

6.3.3.2 Scenario Definitions

For the purpose of conducting incremental analyses of the different options of fuel use, four scenarios have been defined. In all scenarios it is assumed that the output of gasoline, diesel, or jet fuel from the refinery are sold at the local market or if excess amounts are produced for export. The utilization of the output of HFO, associated, gas and LPG in the different scenarios are as follows:

- *Scenario 0:* The output of HFO is used for power production in N'djamena, Sarh, and Moundou, and extra amounts of HFO/crude oil produced is sold internationally.
- *Scenario 1:* The output of HFO is sold at the market price and power production is based on associated gas.
- *Scenario 2:* This scenario is the same as Scenario 1 with the addition that some of the remaining associated gas is sold to the industrial zone in Farcha—a brick factory.
- *Scenario 3:* This scenario is the same as Scenario 2 but with the addition that LPG from the refinery is sold to the local distributors in N'Djamena and the remaining quantities of LPG are exported to Cameroon and world markets.

6.3.3.3 Criteria for Economic and Financial Viability

The criteria for determining the economic and financial feasibility of a project is the net present value (NPV) of the project's net cash flow over a selected period.

6.3.3.4 General Assumptions

The following issues have been considered:

- Calculation period
- Calculation rate and financial interest rate
- Currency denomination

Calculation period

The production profile for the Sedigi oil field depends on the daily production in each of the three cases 1, 2, and 3. The production period in Case 1 is more than 25 years, in Case 2 more than 20 years, and in Case 3 it is 13 years. However, despite the different production periods a calculation period of 15 years of operation has been used for all cases. Terminal values beyond the 15 years of operation have all been defined as zero.

Economic and Financial Discount Rates

The real economic discounting rate for projects in emerging economies is country specific and is normally given by the local planning agency or Ministry of Finance. The Bank generally estimates the economic discounting rate at between 10 and 12 percent per year in emerging economies. An economic discounting rate of 12 percent per year has been used.

In the financial calculations, the requirements are that discounting rates shall be equal to the return on equity investment if undertaken by the private sector. Private investors will require real interest rates above 15 percent per year while state investors would require rates in line with the above-mentioned 10–12 percent per year. In this report an interest rate of 15 percent is used in the financial calculations and the sensitivity analyses was carried out using a rate of 20 percent.

Currency

All calculations have been made in U.S. dollars, which is the standard currency for the international oil sector. Items quoted in local currencies have been converted to U.S. dollars with the currency exchange rate of June 2002, which was 660 FCFA per U.S. dollars.

Prices and Inflation

Calculations have been performed at a fixed 2002-price level.

6.3.3.5 Economic Fuel Cost

The economic cost of fuels in Chad is composed of the current import prices excluding taxes. The present cost of LPG in N'Djamena is assumed to include the components outlined in Table 6.11.

Table 6.11 Cost Structure of LPG Import Bottled in 6 kg Units

	Cost per kg in 6 kg bottles FCFA	**Cost per kg in 6 kg bottles US$**
Cameroon LPG plant	591	0.89
Transport	146	0.22
Duty & tax	71	0.11
N'Djamena	808	1.224
Bottling and storage	187	0.28
Local transportation	15	0.03
Margin to grosser	76	0.11
Subsidy	-733	-1.11
Retail margin	25	0.03
Sales prices	378	0.57

Source: World Bank estimates.

The export price of LPG corresponds to the world market export price at the port of Doula in Cameroun (estimated at FCFA 215,000 per ton) minus the cost of transporting the LPG to N'Djamena, which is estimated at FCFA 160,000 per ton and includes capital costs of trucks for transport but not tanks for storage. This results in an export price in N'Djamena of FCFA 55,000 per ton.

This is a conservative estimate. The estimated world market export price of FCFA 215,000/t is much lower than the above-mentioned price from the refinery in Douala of FCFA 519,000/t[21] so there is a potential for selling LPG in Cameroon at bulk prices in the range of FCFA 400–500/t. However, Cameroon and Nigeria are also considering expanding LPG production and there are uncertainties attached to the market prospects in the region. Also, the economic LPG price will not fall below the price of the lowest cost alternative fuel. The cost of gas for power production is set to zero. The cost of associated gas at the wellhead is set to zero (both economic and financial). But beside this cost there may be a case for including the value of reducing CO_2 emissions.

The economic cost of CO_2 emissions can refer to either abatement or reduction costs (that is, the cost of eliminating the CO_2 emission) of damage costs (that is, the economic cost of damages to the physical and biological environment caused by the CO_2 emission). In principle the lower of the two estimates should be used.

In this report all calculations are presented using economic costs of 0 as the minimum value and US$20 per ton CO_2 as the maximum. The amount of CO_2 in the flared gas is calculated to be 2.9 tons per ton of gas (3.1 ton per Sm^3).

To find the CO_2 reduction cost of this specific flaring reduction project in Chad the CO_2 value, which balances the NPV of net benefits for the maximum gas use scenario (Scenario 3) with the NPV of net benefits for the scenario with no gas use (Scenario 0) is calculated. As replacement of HFO by gas reduces the emission of CO_2, this CO_2 benefit has been included in the analyses. It is assumed that HFO will cause an emission of 27 percent more CO_2 than gas when producing the same amount of electric energy.

The cost of HFO for power production is set equal to the import price from the Cameroonian port of Kribi. The assumption is an HFO price at Kribi of US$25 per barrel, and the transport cost US$9 per barrel, bringing the HFO price to US$34 per barrel in N'Djamena. The value of the quantities of HFO that will not be used for power production and have to be sold on the world market is set equal to the netback price from Kribi, that is: US$25 + US$9 = US$34 per barrel. The value of gas for industrial use at the brick factory is assumed to be the avoided cost of HFO, as this would be the alternative fuel for a new factory. The current economic fuel costs are in Table 6.12.

[21] The price is elevated because regional markets are imperfect with many captive customers and little international trade. Furthermore, since traded volumes are low the LPG parcels are small leading to high freight rates—sometimes in the excess of US$ 150/t (FCFA 99,000 /t).

Table 6.12 Economic Fuel Costs—Year 2002

	Unit	FCFA	US$
Gasoline—cif N'Djamena	liter	317	0.48
Gasoline—cif Cameroon border	liter	254	0.38
Diesel—cif N'Djamena	liter	317	0.48
LPG—cif N'Djamena	kg	808	1.224
LPG—export from N'Djamena	kg	55	0.083
HFO—(netback from Kribi)	barrel	22,440	34.0
HFO—export	barrel	10,560	16.0
Value of gas to brick industry	ton	122,644	186.0
Value of gas for power production	ton	0	0
Cost of flaring associated gas	ton CO_2	13,200	20

6.3.3.6 Financial Fuel Prices

The financial fuel prices for some of the fuels are the same as the economic cost and for others quite different. The financial prices of diesel and gasoline are again set at the import prices cif N'Djamena, and this is also the case for the HFO price. The financial sales price of LPG is the same as the one used as the economic cost, and this is also true for the LPG export price. The price of gas for power and brick production is the alternative price, which is the price of HFO cif N'Djamena. The financial sales price of gas has been set at the price of the cheapest alternative fuel for the enduser. This way it is ensured that the enduser will not lose out on the gas use. In Table 6.13, the financial fuel prices are listed.

Table 6.13 Financial Fuel Prices—Year 2002

	Unit	FCFA	US$
Gasoline—cif N'Djamena	liter	317	0.48
Gasoline—cif Cameroon border	liter	254	0.38
Diesel—cif N'Djamena	liter	317	0.48
LPG—cif N'Djamena	kg	808	1.224
LPG—export from N'Djamena	kg	55	0.083
HFO—(netback from Kribi)	barrel	22,440	34.0
HFO—export	barrel	10,560	16.0
Sales price of gas to brick industry	ton	122,644	186.0
Sales price of gas for power production	ton	122,644	186.0

6.3.3.7 Investment Costs

Based on the investment costs presented in Section 6.3.1, the economic investments in the four scenarios of the two production cases are as follows:

Table 6.14 Economic Investment Cost per Case and Scenario, million US$

Investment Cost	Case 1 Minimized flaring	Case 2 Reflecting demand
Scenario 0	113.1	133
Scenario 1	149.1	169
Scenario 2	149.5	169.3
Scenario 3	154.7	174.6

As the financial evaluations are seen from the perspective of the state-owned oil producing and refining company, the investment costs at the endusers of gas (STEE, brick factory, and LPG distributors) are not included in the analysis.

Table 6.15 Financial Investment Costs per Case and Scenario, million US$

Investment Cost	Case 1 Minimized flaring	Case 2 Reflecting demand
Scenario 0	78.1	98.0
Scenario 1	114.1	134.0
Scenario 2	114.1	134.0
Scenario 3	114.1	134.0

6.3.3.8 O&M Costs

The annual O&M costs have been estimated at 5 percent of the above shown investment costs. In Scenarios 0, 1, 2, and 3, they are assumed to remain the same throughout the production period.

6.3.3.9 Results of Economic Analysis

The results of the economic analyses in the three production cases with NPV 15 years are shown in the Tables 6.16-6.19.

Table 6.16 Case 1—Minimization of Flaring, US$20 per ton CO_2

CASE 1	Benefits	Costs	Net Benefits	Marginal Benefit of Reduced Flaring	Gas Flared %
Scenario 0	201.2	170.1	31.1	–	100
Scenario 1	209.0	175.8	33.1	2.0	39
Scenario 2	212.3	175.2	37.1	6.1	35
Scenario 3	226.8	173.5	53.3	22.2	0

Table 6.17 Case 2—Production Reflecting Demand for Refined Products, US$20 per ton CO_2

CASE 2	Benefits	Costs	Net Benefits	Marginal Benefit of Reduced Flaring	Gas Flared %
Scenario 0	220.3	193.9	26.5	–	100
Scenario 1	228.9	199.6	29.3	2.9	48
Scenario 2	232.3	198.9	33.4	6.9	44
Scenario 3	247.7	196.3	51.4	24.9	9

Table 6.18 Case 1—Minimization of Flaring, US$0 per ton CO_2

CASE 1	Benefits	Costs	Net Benefits	Marginal Benefit of Reduced Flaring	Gas Flared %
Scenario 0	201.2	148.9	52.3	–	100
Scenario 1	205.5	167.5	38.0	-14.3	39
Scenario 2	208.6	167.9	40.8	-11.5	35
Scenario 3	223.0	173.5	49.5	-2.8	0

Table 6.19 Case 2—Production Reflecting Demand for Refined Products, US$0 per ton CO_2

CASE 2	Benefits	Costs	Net Benefits	Marginal Benefit of Reduced Flaring	Gas Flared %
Scenario 0	220.3	170.1	50.2	–	100
Scenario 1	225.4	188.7	36.7	-13.5	48
Scenario 2	228.6	189.1	39.5	-10.7	44
Scenario 3	244.0	194.7	49.3	-0.9	9

The above results illustrate that both at a cost of US$0 and US$20 per ton CO_2 it is economically viable to use the flared gas and that the gas use is most viable when including LPG utilization as in Scenario 3.

Sensitivity Analyses

The above results depend on the correctness of a number of assumptions. In order to test the sensitivity of some key assumptions three sensitivity tests have been carried out:

- An increase of the discounting rate from 12 percent to 17 percent.
- All investments are increased by 20 percent. This is particularly relevant since some of the investment estimates are based on the quotations of regional contractors (for example, from Sudan) which seem to be somewhat below world market prices.

- The price of LPG is reduced by 25 percent. This is reflecting the uncertainty of the border price of LPG and the possibility to export LPG to Cameroon, Nigeria, or the world market.

The results of the sensitivity analyses show (in all of the below cases only scenario 3 with LPG production included is considered):

- That an increase of the discounting rate from 12 percent to 17 percent leads to a reduction of the marginal benefits but even with no value attached to CO_2 reductions the project remains economically viable for Scenario 3 (with an NPV of around US$6 million) whereas the NPVs are negative for Scenarios 1 and 2.
- That an increase in the investments of 20 percent in all scenarios leads to a reduction of the marginal benefits but even with no value attached to CO_2 reductions the project remains economically viable for all three scenarios.
- That a decrease in LPG value (on the domestic market as well as on the export markets) of 25 percent leads to a reduction of the marginal benefits but even with no value attached to CO_2 reductions the project remains economically viable for all three scenarios.

6.3.3.10 Results of Financial Analysis

The results of the economic analyses in the three production cases using NPV US$ million are shown in Tables 6.20 and 6.21.

Table 6.20 Case 1—Minimization of Flaring

CASE 1	Income	Costs	Net Income	Marginal income, reduced flaring	Obtained CO_2 reduction million ton (as NPV)	Needed support US$/ton of CO_2
Scenario 0	175.7	76.4	99.3	–	–	–
Scenario 1	206.0	111.5	94.4	-4.9	0.5	9.6
Scenario 2	208.5	111.5	96.9	-2.4	0.5	4.3
Scenario 3	221.4	111.5	109.9	10.6	1.1	-9.5

Table 6.21 Case 2—Production Reflecting Demand for Refined Products

CASE 2	Income	Costs	Net Income	Marginal income, reduced flaring	Obtained CO_2 reduction million ton (as NPV)	Needed support US$/ton of CO_2
Scenario 0	191.2	95.8	95.5	–	–	–
Scenario 1	219.3	130.9	88.4	-7.1	0.5	13.9
Scenario 2	221.9	130.9	90.9	-4.6	0.5	8.3
Scenario 3	235.7	130.9	104.8	9.3	1.2	-8.1

Financially, flared gas use from the Sedigi oil field is only viable in the case of LPG production. When interpreting the above results it should be noted that it is realistic to achieve a financial CO_2 credit of US$3–5 per ton CO_2 reduced (for example, from the Prototype Carbon Fund or similar). However, flared gas use will not be financially viable in the case of only converting the STEE plant to gas since it is presently unrealistic to achieve carbon credits of US$10–14 per ton CO_2 reduced.

6.3.3.11 Sensitivity Analyses

The results of the sensitivity analyses show:

- That at an increase of the discounting rate from 15 percent to 20 percent Scenario 3 is still financially viable without carbon credits whereas Scenarios 1 and 2 will need financial support in the range of US$20–30 per ton CO_2 to be financially viable.
- That at an increase in the investments of 20 percent Scenario 3 is still financially viable without carbon credits whereas Scenarios 1 and 2 will need financial support in the range of US$7–24 per ton CO_2 to be financially viable.
- That at a decrease in LPG prices of 25 percent (on the export markets) Scenario 3 is still financially viable without carbon credits in both Cases 1 and 2 whereas Scenarios 1 and 2 only are financially viable in Case 2 without financial support.

6.4 Chad Conclusions

- Total elimination of flaring is possible as a financial win-win scenario even when not considering the possibility of obtaining carbon credits for the reduced CO_2 emission provided that the project includes LPG usage as described in Scenario 3. This conclusion is reinforced in that it is possible to obtain carbon credits in the range of US$3–5 per ton CO_2. The economic analysis shows that all scenarios are economically viable even with no value attached to CO_2 reductions.
- Gas use at the N'Djamena power plant is the only option for substantial reduction of the gas flaring inside Chad. The power plant is an "anchor customer."
- Small-scale use projects can improve the economic benefit of using gas at the power plant. Those are: providing natural gas (dry gas) to industrial consumers—notably for brickmaking; making an LPG bottling plant and disseminating LPG to domestic consumers and export (however, the dissemination to domestic consumers only yields benefits if pricing and subsidy policies are corrected).
- By reducing the cost of power production, the power station rehabilitation and gas usage projects will lead to lower power tariffs and create a financially sustainable basis for expanding the power supply far beyond the present 11,000 consumers. The same effect could partly have been achieved in what is called Scenario 0, that is, only bringing the oil pipeline to N'Djamena, using HFO in the power plant and flaring the gas at the oil field. However, the production of HFO from the refinery would be insufficient to meet all of STEE's demand even in Case 2 where the refinery capacity and the oil production rate reflect the need for diesel and gasoline in Chad. Gas use is therefore a more sustainable solution for the

population of N'Djamena in that it constitutes secured, inexpensive, clean, and reliable fuel for power production for the next two decades.

- Even though not quantified in the calculations in this report there will be a considerable positive impact on Chad's balance-of-payment if the gas is used instead of being flared. The gas use will allow more oil exports and part of the gas can be exported in the form of LPG.
- Gas use improves Chad’s energy security and insulates it somewhat from negative changes in external economic conditions. This is a major, if not always economically quantifiable, advantage to a government, which provides long-term certainty for business investors, allowing consideration and financing of longer-term investment opportunities, thus leading to more rapid economic development.
- Gas for industrial plants can be priced so that it will be a least-cost fuel for industrial plants, for example, brickworks. This would provide considerable stimulus for the expansion of the economy in N’Djamena and lead to increased industrial production, import substitution, and higher employment.
- LPG production increases the marginal benefits of the project significantly. The gas usage scheme is not feasible without LPG production.
- Providing LPG instead of diesel for rural electrification in combination with agricultural development (polder pumping) could show potential for increased LPG use and deserves further investigation.
- A number of constraints for gas use should be mentioned:
  - The present LPG subsidy policy is not sustainable and the government may not be able to fund LPG subsidies in a scenario with expanded LPG consumption unless subsidies are reduced.
  - The financial project analysis shows that neither a state-owned oil company or private interests will be likely to implement the project. The flaring reduction project will therefore need concessional financing to be implemented.
  - Low capacity to expand the power supply may constrain demand growth and delay the achievement of total eliminating flaring as well as impacting negatively on the project economics.
  - Energy demand in small communities along the gas pipeline is insignificant at present and branching off from the pipeline will probably not be viable before larger end-use options become relevant along the pipeline.
  - Based on the documents available to the team it appears that the present design of the Sedigi field facilities raises safety concerns. It is therefore strongly recommended to review the present design before proceeding with the plans to put the field in operation.
- In general, the Sedigi project illustrates that small-scale/medium-scale use of flare gas can add important environmental, social, and wider developmental aspects to

a developing country oil project without jeopardizing economics or financial viability. However, the marginal financial gains require a stimulus to pure market forces.

- Finally, that dry flare gas can be offered to industrial consumers at a price equivalent to or lower than the cheapest alternative opens up interesting perspectives. In N'Djamena the local industry is very underdeveloped partly because of the high fuel prices and the unstable supply conditions that are the consequences of Chad's landlocked location. One might say that this represents a negative chicken-and-egg situation: industrial fuel demand remains low because there is little industry and the low demand will constrain the financial feasibility of new energy supply projects. However, experience from all over the world shows that once an inexpensive and stable fuel source like natural gas is available the situation turns around and a number of industries, both small and large, will be attracted to the place. In the case of Chad, domestic industry is likely to establish itself and crowd out imports giving higher value added (and thus higher employment) in the country.

6.5 Chad Recommendations

The commissioning of the Sedigi field should include the following modifications to accommodate gas use:

- Compression and dehydration of the gas at the site
- Construction of 340 km 6-inch gas pipeline to N'Djamena
- Supply of dry gas to power plant and industrial consumers in N'Djamena
- Production of LPG at Farcha Refinery
- Throughput at refinery to match need for transport sector fuels in Chad

The Government of Chad should be supported to prepare and implement a gas usage project consisting of gas supply to the STEE power plant, possibilities to supply dry gas to a new industrial zone in Farcha, and LPG production for the local market and export.

The capacity of the Farcha refinery should be in the range of 3,000 to 3,500 bpd in order to obtain the best project economics. Efforts should be made to ensure that flaring will be kept at a minimum or eliminated. This will include investigating options for continuous operation of the STEE power plant and promoting industrial end-use in the new industrial zone.

A followup study is needed to determine how the project might best be structured commercially to ensure its implementation (that is, recommend best practices to project participants). As a first step of such a project it is recommended that the Ministry of Mines, Energy, and Oil prepare a detailed gas usage strategy where subjects like gas use promotion, natural gas and LPG pricing, LPG subsidies phase-out, and institutional and regulatory issues of gas use can be dealt with.

Consideration should be given to the construction of an 8-inch gas pipeline instead of the planned 6-inch gas pipeline from Sedigi to N'Djamena. The difference in cost will be marginal, and the bigger pipeline gives more flexibility to expand gas supply if new oil deposits (with exploitable associated gas) are found or if production at Sedigi is greater than presently expected (for example, increased demand following economic development associated with the Doba project).

The project has highlighted the need to deal with the LPG distribution at a strategic level. Since LPG production will be an integral part of many flare gas usage projects in developing countries it will be necessary to investigate the framework for LPG distribution as part of a decision to produce LPG. Future LPG demand (local and regional) is a critical factor and the relation between the government subsidy policy and LPG demand has to be scrutinized. It could be very costly for a government to keep up a high subsidy to LPG at the same time as the market is expanded and it may also be unwise, if alternative domestic fuels are actually a better option. Conversely, local demand for LPG may dwindle once subsidies are reduced and thereby undermine the economics of an LPG usage scheme.

7 Case Study II: Ecuador

7.1 Introduction

As mentioned, the main objective of the present study is to assess the technical and economic feasibility of using flared gas in various applications, ranging from rural electrification to commercial and industrial usage. Market opportunities for use of flared gas to support sustainable development and poverty reduction are emphasized. The definition of two viable pilot projects, which could progress to a detailed feasibility and implementation, is inherent to this task. As with the Chad case study a main selection criterion for the pilot projects is their poverty reduction potential.

7.1.1 General

The Republic of Ecuador is among the smaller countries in South America, covering 283,520 square kilometers on the northwestern coast of South America. Mainland Ecuador is divided into three regions: the coastal region, the Andean highlands with the capital Quito, and the Amazon region. Most of Ecuador's 12.1 million[22] inhabitants live in the coastal region and in the highlands.

Figure 7.1 Map of Ecuador

Table 7.1 Population in Ecuador by Region

	% of total
Highlands	45
Coast	49.5
Amazon	4.5
Galapagos & Others	0.75

[22] INEC: VI Censo de población— Noviembre 2001 población del Ecuador por areas y sexo, según provincias (Datos provisionales). 2002.

Approximately 61 percent of the population live in urban areas,[23] compared with 58 percent in 1990.[24] This is somewhat less than in its neighboring countries, Peru and Colombia, where more than 70 percent[25] of the population is urban. The trend in rural to urban migration is expected to continue.

During the last part of the 1990s, gross national income (GNI) per capita fell, reaching US$1,210 in 2000—slightly higher than the average for other lower-middle-income countries (US$1,140).[26]

Poverty is rampant in Ecuador. The percent of the population living in poverty doubled between 1995 and 2000—from 34 to 67 percent.[27] Of these, more than 20 percent live in extreme poverty[28] (insufficient income for a minimum food basket). These conditions have led to a massive immigration to the United States and Europe. Remittances from Ecuadorian workers living abroad is now the second largest source of foreign exchange earnings (around US$1.4 billion in 2001[29]) after the sale of oil.

"Dollarization" of the economy in 2000 contributed to macroeconomic stabilization, notably curbing inflation (from 96 percent in 2000 to 37 percent in 2001[30]). After a negative growth rate of 6.3 percent in 1999 and 2.8 percent in 2000, a significant growth rate in 2001 of 5.1 percent also helped improve the economy. At 3.0 percent, the growth rate, however, was lower in 2002 mainly because of the lower oil prices and the global economic slowdown.

Ecuador is extremely vulnerable to external economic shocks considering its oil sector accounts for about one-fifth of the country's economy and is the most important source of foreign exchange. Oil export revenues accounted for approximately 45 percent of Ecuador's total merchandise exports in 2001 and nearly 40 percent of the government budget for 2002.[31]

Ecuador has been a presidential democracy since 1979 and has been marked by instability over the past decade because of poor economic performance. In the past six years the country has had five different presidents.

A new constitution was approved in 1998. The new constitution and ongoing regulatory reform aim to stimulate private investment. Sectors previously dominated by state monopolies as well as the provision of public services have been deregulated and opened up to private investment with the aim of spurring economic development.

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[23] INEC: VI Censo de población—Noviembre 2001 población del Ecuador por areas y sexo, según provincias (Datos provisionales). 2002.
[24] INEC: V Censo de población 1990.
[25] World Bank (devdata.worldbank.org).
[26] World Bank: http://www.devdata.worldbank.org, 2002.
[27] EU: The EU's relations with Ecuador, 16.05.2002.
[28] SIISE, vers. 2.5: La pobreza y la extrema pobreza de consumo, 2002.
[29] EIA: Ecuador Country Analysis Brief, December 2001, p1.
[30] EIA: Ecuador Country Analysis Brief, December 2001.
[31] EIA: Ecuador Country Analysis Brief, December 2001.

7.1.2 The Amazon Region

Most of Ecuador's oil reserves are located in the Amazon region, known as the Oriente. The Amazon region is divided into six provinces, which constitute 48 percent of Ecuador's total surface area but have the smallest proportion of the country's inhabitants (4.5 percent).

Oil production is concentrated in the Sucumbíos and Orellana provinces, which have approximately 130,000 and 86,000 inhabitants, respectively. There are seven towns in the two regions—notably Lago Agrio/Nueva Loja, Francisco de Orellana (Coca), La Joya de los Sachas, Aguarico, and Shushufindi—but no big cities. The rest of the area is characterized by indigenous Amazon populations that tend to live scattered or in smaller settlements and small communities with up to about 300 families. The population density in Sucumbíos and Orellana is 7 and 4 per km^2, respectively.

Of the approximately 550,000 people in the Amazon, about 30 percent are indigenous people belonging to eight different tribes and 70 percent are settlers. Short-term contracts with the oil companies and other activities also bring unskilled laborers to the area.

Settlers started moving to the Amazon region about 30 years ago at the same time the oil investigation and exploration activities began in the region. New settlers keep coming to the region in search of land and work near the oil installations.

7.1.2.1 Social context

Updated social data is not available for the Amazon region. According to a Bank project information document,[32] however, social indicators for indigenous people fall significantly below the national average in terms of infant mortality, female illiteracy, child malnutrition, access to basic sanitation services, and access to productive infrastructure.

Child mortality in 1999 was 37 per 1000 live born for the country as a whole but 52 per 1000 for the Amazon Region. Immunization of children under two was also lower in the Amazon with only 55.6 percent compared with 76.9 percent for the whole country in 1999.[33] In 1999, a study[34] carried out in the provinces of Sucumbíos and Orellana indicated that the risk of cancer in these regions was three times greater than in other parts of the country. In specific cases, such as throat and liver cancer, the risk was even higher. Rivers traditionally used for water supply are highly contaminated. The dispersal of the population limits access to safe water and electricity to only some of those living in towns and villages.

According to Petroecuador, LPG is widely used for cooking purposes in the Oriente. No exact numbers are available, however. The local consumption pattern is that the population will use LPG as long as they have sufficient funds to buy it and, when the funds run out, they will gather firewood instead. However, there does not seem to be a market for firewood, as each family collects its own. Outside the towns, LPG is more expensive than the government's official price

[32] World Bank: Indigenous Peoples Development Project; Project Information Document. 1997.

[33] CIISE version 2.5.

[34] A study carried out by the Pastoral Social del Vicariato de Aguarico in cooperation with the University of London and Medicus Mundi described by OEI 1999 and CONFENIAE.

of US$1.60 per bottle of 15 kilograms. The unofficial price often will be in the range US$3.5–5 because of the difficult boat transport from the towns out to the small settlements in the jungle.

Few areas have electricity. The electricity is either provided via a local grid (the Sucumbíos grid) or via small local networks. It appears that the provision of electricity is not constant. Some communities close to oil production facilities have been asking the oil companies to provide them with electricity because the ordinary network has been slow to expand. An average household spends about US$10 per month on electricity. If bills are not paid, the connection is cut.

7.1.2.2 Economic context

The Amazon region is characterized by a subsistence economy and suffers from unemployment. The available workforce is mainly unskilled. The few people who do get an education tend to leave the region in search of employment.

The indigenous people traditionally lived from hunting, gathering, and fishing, and to a very large extent they still do. The introduction of settlers and oil companies has reduced their territory and many are converting to subsistence farming.

The settlers are mainly farmers and small service providers. The plots of land are all 50 hectares; however, some families have more than one plot of land. Subsistence farming characterizes agricultural production and surplus production as being sold at local markets. Some coffee is produced in the area. The fall in market prices, however, has negatively impacted the local economy.

7.1.2.3 Government policy in the area

The government does not have a development policy for the region. The Institute for Amazonian ecodevelopment (Instituto para el ecodesarrollo regional amazonico [ECORAE]) is responsible for strategic planning in the Amazon region.[35]

ECORAE is funded by money from oil production. Companies pay 35 cents per barrel extracted (to increase to 50 cents in the near future) to a development fund managed by Petroecuador. The fund's current annual disbursement is approximately US$5 million. Of this money, 10 percent goes to ECORAE and the other 90 percent is distributed between the provinces and municipalities of the Amazon region for local development.

ECORAE was set up 10 years ago to support sustainable development in the Amazon region. A master plan was made in 1996, and since then the following activities have been prioritized:

- Dialogue with the oil companies[36]
- Ecotourism
- Transport
- Basic sanitation

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[35] An institution called Odeplan is responsible for regional development planning in the other regions of the country.

[36] ECORAE is participating in the development of procedures for consultation with the people of Amazonia, supported by the World Bank.

- Agricultural and forestry development
- Ecosystem services

7.1.2.4 Oil companies' relationship with the local population

Relations between the local population on the one side and the oil companies and government on the other side have never been good. During the last decade, private companies appear to have worked on improving relations. Environmental impact legislation requires that the oil companies develop a community relations plan that also aims at improving the relationship between the companies and the local population. Often community workers are employed to identify projects and to help. An example is Repsol-YPF, which supplies electricity to two small Indian communities within the block. Furthermore, they built schools and health clinics, hired doctors, and set up transportation facilities within their block.

In summary, distinguishing between indigenous people and settlers is important, and more important is being sensitive to cultural issues in the Amazon region. A clear potential exists for improving the quality of life from flare gas use whether it be for electricity generation or cooking. Because of the sparse and dispersed population, however, only those living in towns or small communities could be potential receivers of electricity and only those with relatively easy access to market could be able to benefit from cheaper LPG. Improvements to air quality would, however, benefit everyone.

7.1.3 Energy Supply and Consumption

Ecuador possesses large hydropower, petroleum, and gas reserves. Primary energy production in the year 2000 was 23.67 million tons of oil equivalent (MMTOE), a 6.6 percent increase over the previous year.

Table 7.2 Primary Energy Production, year 2000, MMTOE

	1,000 TOE	**%**
Associated Gas	418	1.8
Bagasse	280	1.2
Oil	20,933	88.4
Wood fuel	1,310	5.5
Hydro	727	3.1
Total	**23,668**	**100**

Source: Ministry of Mines and Energy

Total Primary Energy Supply (TPES)[37] per capita is 0.74 TOE. Electricity Consumption equals 645.34 kilowatt-hours per capita and is dominated by the transport, residential, and industrial sectors as is shown in Table 7.3.

[37] TPES = Indigenous production + imports - exports - international marine bunkers +/- stock changes.

Table 7.3 Final Energy Consumption by Sector, MMTOE

Sector	1996	(%)	1998	(%)	2000	(%)
Residential	1,391	22.3	1,408	22.5	1,884	27.1
Private and public service	264	4.2	307	4.9	281	4.0
Industrial	1,418	22.7	1,359	21.7	1,425	20.5
Others	100	1.6	102	1.6	123	1.8
Transport	3,078	49.2	3,090	49.3	3,233	46.5
Total	6,251	100	6,266	100	6,946	100

Source: International Energy Agency (IEA)

Ecuador's current energy policy aims to encourage private investment in development of oil and gas reserves as well as electricity distribution, which were all previously government monopolies. As part of its structural reform efforts, the government is also offering increased legal security to foreign investors. Promoting investments in infrastructure facilities to improve transportation, transmission, and export of energy commodities is a high priority for the government.

Consumer prices for energy are highly subsidized, and the IMF has conditioned support on structural reforms including reduction of domestic fuel subsidies and lessened restrictions on foreign investment. Attempts to remove subsidies have been met with strong popular opposition.

Nonhydro renewable energy is marginal, but wind, photovoltaic, biomass, and geothermal have access to special financing through the Fund for the Electrification of Rural and Suburban Areas (FERUM).

7.1.4 Regulatory Framework

Three laws and a set of regulations relate directly to gas flaring in Ecuador:

- Ley de Hidrocarburos, 1978 (The Hydrocarbon Law)
- Ley de Régimen del Sector Eléctrico, October 1996 (The Electricity Law)
- Ley de Gestión Ambiental, 1999 (The Environmental law)
- Reglamento Sustitutivo del Reglamento Ambiental Para las Operaciones Hidrocarburíferas en el Ecuador, 13 February 2001 (The regulation to substitute for the environmental regulation of hydrocarbon operations in Ecuador).

The salient aspects of this legislation are discussed below. They form part of Ecuador's process of regulatory reform, which includes a new constitution (1998). The new constitution aims to create institutions that are more capable of responding to a "new international environment and the needs of national development." Petroleum and electricity have been identified in the new constitution as "strategic areas" of the economy. Formerly government monopolies, the government sees the accessibility of these areas to foreign investment as an important driver for development. The constitution gives legal security to foreign investors by stipulating that laws issued after the signing of the contracts cannot modify the contracts.

7.1.4.1 Ley de Hidrocarburos, 1978 (The Hydrocarbon Law)

This law sets the framework for the sector and defines the role of the Ministry of Mines and Energy, the role of the National Directorate for Hydrocarbons placed in the Ministry, and the role of the state-owned company Petroecuador. The law establishes that Ecuador's hydrocarbon resources belong to the state, which explores and exploits them via Petroecuador. Petroecuador can, however, contract exploration and exploitation to private companies. In 1993 a reform of the hydrocarbon law introduced production-sharing contracts. In December 2000, Ecuador's Constitutional Tribunal rejected a government reform plan that would have allowed private companies to take operational control of Petroecuador's top five fields. Articles 34, 35, 39, and 41 of the law address issues pertinent to gas flaring.

Article 34 complicates the commercialization of flare gas by stipulating that natural gas obtained from exploitation of oil deposits belongs to the state and can only be used by the contractors or associates in the quantities necessary for operation of exploitation and transport or for reinjection in deposits after previous authorization from the Ministry of Energy and Mines. In condensate fields or deposits with a high gas-to-oil relation, the Ministry of Energy and Mines can demand recirculation of the gas.

Sale of excess gas is addressed by Article 35. It states that the State of Ecuador, via Petroecuador, can enter into additional contracts with its respective contractors or associates or into new contracts with others with a recognized technical and financial capacity to use the gas derived from the oil deposits for industrial or commercial use. Petroecuador can also extract the liquefiable hydrocarbons from the gas extracted by the contractors or associates.

Article 36 states that if Petroecuador wants the gas for industrial purposes, generation of electricity, commercial use, or any other use, contractors or associates shall at no cost hand over to Petroecuador the gas they extract and do not use for their own production purpose. Petroecuador will in such cases only pay the transfer cost incurred by the contractors or associates.

Burning of gas is addressed in Artitcle 39. Article 39 states that the use of any excess gas (gas that cannot be reinjected or used by Petroecuador) must be stipulated under special agreements. Finally, air emission or burning of natural gas is prohibited unless an authorization to do so is given by the Ministry. In theory, the Ministry could prohibit all gas flaring.

7.1.4.2 Ley de Régimen del Sector Eléctrico, October 1996 (The Electricity Law)

According to the constitution, the provision of electricity service is a public service the government should ensure. Ensuring electricity service, however, can be done directly or delegated to private or mixed enterprises. The Electricity Law defines the new structure of the electricity industry in Ecuador with the aim of promoting the sector's efficiency and private sector participation. It defines the wholesale electricity market and the new institutions COMOSEL, CONELEC, and CENACE, which will be described later. The law allows the government to sell up to 39 percent of the shares in existing electricity generation, transmission, and distribution enterprises to private operators, domestic or foreign, and up to an additional 10 percent to electricity sector workers. The "Solidarity Fund," a fund set up to fund human and social development programs, will hold the remaining shares.

7.1.4.3 *La Ley de Gestión Ambiental, 1999 (The Environmental Law)*

The Ministry of Energy and Mines plays a dominant role in environmental issues, which emphasizes the Environmental Ministry's weakness. This relatively new law defines a decentralized system for environmental management. The Section for Environmental Protection under the Ministry of Mines and Energy is part of this decentralized system and is responsible for environmental protection in the hydrocarbon and mining sector.

Environmental protection in the electricity sector is under the auspices of CONELEC. Institutions still overlap regarding environmental management and areas of competence that are not clearly defined. For example, both the Ministry of Environment and the Section for Environmental Protection seem empowered to approve environmental studies and plans for oil production when oil production is to take place in protected areas. Several oil production fields currently are partly or completely in protected areas.

7.1.4.4 *Reglamento Sustitutivo del Reglamento Ambiental Para las Operaciones Hidrocarburíferas en el Ecuador, issued by the Ministry of Energy and Mines, February 13, 2001*

The regulation establishes environmental management requirements, including emission standards and environmental impact assessment, and defines the jurisdiction and competence of the National Directorate for Environmental Protection (DINAPA) under the Section for Environmental Protection in the Ministry of Energy and Mines.

To try to improve the difficult relations between the local communities and the oil-producing companies, environmental impact studies must include a baseline study of the socioeconomic and cultural situation of the local population and present a plan for community relations. The plan must include a program for activities to be developed with the local population(s) in question. It will also include information and communication strategies and possible compensation plans, compensation projects, and plans for mitigation of socioenvironmental impacts and a participatory environmental education program. According to some of the oil companies visited, several of the local communities have provision of electricity high on their list of demands.

Before being approved by the Ministry of Energy and Mines, an environmental impact study, including its remediation plans, has to be presented at a public hearing. The Ministry (Section for Environmental Protection) should coordinate this hearing, and representatives of the oil production company, their environmental consultant, and the local population should participate.

In a participatory process with indigenous groups and other communities in oil-producing areas, the National Directorate for Environmental Protection is currently developing regulations and guidelines for community consultations and participation in the different phases of oil and gas projects where these have a social or environmental impact on the indigenous people and other communities living in the project area. The new regulations may also reduce gas flaring because they set new and stricter limits for atmospheric emissions.

Although the regulatory framework does not facilitate the commercialization of flare gas, official agreements provide a means to facilitate the generation of creative measures for benefiting the poorer sectors of society. The EIA process may provide the best legal mechanism to stimulate positive flare gas uses.

*Table 7.4 Atmospheric Emission Limits (mg/m^3)**

Parameter	Expressed in	Maximum reference value	
		Until 31.12.2002	From 01.01.2003
Particulate material	PM	200	100
Sulphur oxides	SO_2	2,000	1,000
Nitrogen oxides (NO_x)	NO_2	500	460
Carbon oxides	CO	350	180
Volatile organic compounds	C	70	35
Polycyclic aromatic hydrocarbons	C	0.01	0.01

* Milligram per dry cubic meter of gas output at 25^{o}C and 101.3 kpa (atmospheric pressure) and 11% oxygen.
Source: Ministerio de Energia y Minas; Reglamiento Ambiental, 2001, p 109.

7.1.5 The Electricity Sector

7.1.5.1 Structure and institutions

Restructuring of the electricity sector began with the new electricity law in 1996 and is still underway. The former state-owned electricity monopoly Instituto Ecuatoriano de Electrification (INECEL), which controlled generation, transmission, and distribution of electricity has been split into 6 generation companies, 1 transmission company, and 19 distribution companies that are to be privatized. These companies are owned by Fondo de Solidaridad (the Solidarity Fund), which was created in 1995. Privatization of the distributors has been delayed several times, in part because of opposition from labor unions and Indian rights organizations.

The new institutional framework for the electricity sector consists of the following organizations:

The Consejo de Modernizacion del Sector Electrico (CONAM-COMOSEL) is in charge of implementing the changes in the electricity industry mandated by the law and of the privatization process of the different electricity companies.

The Consejo Nacional de la Electricidad (CONELEC) began operating in November 1997 as the main regulatory authority for the electricity sector. Through CONELEC, the government can delegate generation, transmission, commercialization, and distribution to the private sector via concessions. CONELEC is also responsible for preparing the national electrification plan, which is mandatory for the public entities and referential to the private companies. The plan currently exists in its third version, the Plan Nacional de Electrificación 2002–2011. The members of CONELEC's board are representatives of the president, members of the production groups, the electricity workers, and the army.

The Centro Nacional de Control de Energia (CENACE) began operating in February 1999 as the operator for the new wholesale market and is in charge of managing the physical and financial operations of the market. CENACE is a nonprofit technical private corporation and its members are the generators, the transmission company, the distributors, and large consumers.

El Fondo de Solidaridad (the Solidarity Fund), mentioned above, currently holds the government's shares of the commercial activities in the sector. The fund is set up to fund human and social development programs, such as formal and nonformal education, child nutrition, water supply and sanitation, social housing, and so on.

7.1.5.2 Tariff setting

The government has historically repressed electricity tariffs, forcing distributors to operate at a loss and obstructing efforts to expand capacity and supply. Subsidies were first cut in 1998, and by 2000 tariff increases made the sector more attractive to private investors. Cross-subsidization of low volume residential electricity users with higher commercial rates has been reduced.

7.1.5.3 Capacity and production

Ecuador relies heavily on hydropower for its electricity production. The country has an installed electricity generating capacity of approximately 3,500MW. Hydroelectric power plants, including the 1,075MW Paute hydro plant, account for half of installed capacity and supply three-quarters of the country's current needs. Supplemental thermal power often is required during the dry season to avoid brownouts if rainfall is insufficient.

Table 7.5 Installed Electricity Generation Capacity in Ecuador, 2000 (MW)

Hydroelectric	1,730
Conventional Thermal	1,750
Total Capacity	3,480

Source: DOE/EIA

In addition to the large generation companies whose assets are controlled by the Solidarity Fund, there are many smaller, mostly isolated, generation units that are not connected to the national interconnected grid (Sistema Nacional Interconectado [SNI]). The thermal power plants that are part of the SNI mostly run on diesel or bunker fuel and have older internal combustion units that have been in operation for more than 20 years and are to be phased out.

Consumption of electricity in Ecuador has grown by about 60 percent over the past decade. Hydropower accounts for roughly 70 percent of production.

Table 7.6 Electricity Generation for Plants Connected to the National Interconnected Grid (SNI) (GWh)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Net Generation	6.2	6.8	7.0	7.3	8.1	8.3	9.0	9.3	9.6	10.1	10.4
Hydroelectric	4.9	5.0	7.0	5.8	6.6	5.2	6.2	6.4	6.5	7.1	7.8
Thermal	1.3	1.8	2.1	1.5	1.5	3.1	2.8	3.0	3.2	3.0	2.6
Net Consumption	**5.8**	**6.3**	**6.5**	**6.8**	**7.5**	**7.7**	**8.4**	**8.7**	**9.0**	**9.4**	**9.7**

Source: DOE/EIA

The 2002–2011 National Electrification Plan lists 146 hydroelectric projects, totaling 11,547 MW. CONELEC hopes to attract private interest in the most promising projects. Some have been or are in the process of being approved by CONELEC. Total hydroelectric potential is estimated at 22,000 MW.

A new gas-fired combined-cycle plant, the Machala power plant in El Oro province, is being built by the U.S.-based Energy Development Corporation (EDC). When fully operational, the plant is expected to generate 312 MW.

Table 7.7 Power Sector Investments in Electrification Plan Period (2002–2011)

Investment Needs	**Required Investment US$ Million**
Generation	1,130
Transmission	178
Distribution (including money from FERUM)	1,127
Total (for years 2002–2011)	2,435

Source: CONELEC

Ecuador's national transmission system (SNT) is composed of a 230-kilovolt (kV) line connecting the largest energy producers with the largest consumers in the central and western parts of the country. Substations are located at Paute, Milagro, Pascuales (Guayaquil), Quevedo, Sto. Domingo, Sta. Rosa (Quito), Totoras (Ambato), and Riobamba. A second 230-kilovolt line connects Paute, Pascuales, and Trinitaria (Guayaquil) to enable electricity generated at these plants to be fed into the grid.

As of 1995, average electrification coverage was 75 percent (95 percent urban and 53 percent rural), being lowest in the Amazon region.

Table 7.8 Electricity Users by Consumer Type in Ecuador (2000)

Consumer Group	**Number of Connections**	**% of Total**
Residential	2,101,967	87.4
Commercial	239,990	10.0
Industrial	29,454	1.2
Public/Government	295	0.0
Other	33,246	1.4
Total	**2,404,952**	**100.0**

Source: CONELEC

7.1.5.4 Electricity supply in the Amazon region

The Empresa Electrica Sucumbíos S.A. (EES) operates an isolated distribution network in the northeastern province of Sucumbíos, not connected to the SNI. The peak load in the grid is currently around 20 MW and the main towns connected are Coca, Nueva Loja, and Shushufindi. The government expects interconnection of the Sucumbíos grid with the national grid to take place as soon as early 2003.

This interconnection would support the proposed TermOriente project, which will expand power supply in the region. The project involves a private investment by Wärtsilä NSD Power

Development, Inc. (WNSD), in the construction of a 270 MW power plant to be run on residual heavy fuels (RFO) from the refinery in Shushufindi. According to the project description, the plant is to be interconnected both with the national grid (at Santa Rosa south of Quito) and with the isolated grid operated by the EES (at the Jivino substation). A company, TermOriente, fully owned by WNSD, will be established for the purpose of financing, constructing, owning, and operating the plant. If carried out, the US$300 million investment will boost power supply in the region and reduce dependency on diesel-fueled steam turbines.

7.2 The Hydrocarbon Sector

According to the constitution, all subsurface resources belong to the state. The oil sector, however, now employs production-sharing contracts that give private investors the right to share in discoveries. Furthermore, private companies, including foreign ones, can now participate in domestic fuel distribution, refining, and transport, although pricing is regulated by the government.

7.2.1 Institutional Setup

The Ministry of Energy and Mines is responsible for policy development and management of the Ecuador's energy resources. The Ministry regulates, monitors, and controls hydrocarbon and mining operations and promotes national as well as international investments in the sector. The Ministry has during the last couple of years been through a restructuring process.

The Ministry has five sections (subsecretarías):

1. Hydrocarbons
2. Mining
3. Environmental protection
4. Electrification
5. Administration

Under the Section for Hydrocarbon is the National Directorate for Hydrocarbons (DNH). The responsibilities of the DNH are defined by the Hydrocarbon Law described above. The directorate is responsible for the development and implementation of the country's hydrocarbon policy and for enforcing the Hydrocarbon Law. It can introduce regulations needed for the appropriate implementation of the law. The Directorate approves or authorizes all phases of the hydrocarbon activities, including the oil companies' plans and budgets for investment; sets limits for oil production; authorizes and monitors the construction of oil and gas pipelines; and controls and monitors the market for LPG. Revenues derived from permits, sale of information, and fines finance the ministry's administration.

The Section (Subsecretaría) for Environmental Protection mentioned above works via the DINAPA with environmental management with regard to the mining and hydrocarbon sector, including monitoring and control of the industries operating in those sectors. The Directorate is also responsible for community relations and participation.

The Section (Subsecretaría) for Electrification is responsible for the promotion of the use of alternative energy sources and efficient energy use, decentralized rural electrification, and standardization of criteria for electrical equipment. Both these sections provide a potentially valuable link to local communities in the development of flare gas alternatives.

7.2.1.1 Petroecuador

Petroecuador is a holding company consisting of the following:

- *Petroecuador*—responsible for coordination of the group's activities, international trade, management of the country's main pipeline, environmental protection, and exploration and production contracts with domestic and international companies.
- *Petroproducción*—responsible for exploration and exploitation of hydrocarbons.
- *Petroindustrial*—in charge of refining processes.
- *Petrocomercial*—responsible for transportation and commercialization of refined products for domestic use.

In 1989, Petroecuador replaced Corporación Estatal Petrolera Ecuatoriana (CEPE), which was founded in 1972 to explore and exploit the hydrocarbon deposits of Ecuador in accordance with the Hydrocarbon Law. Petroecuador can set up companies in association with domestic and international companies. Petroecuador has suffered from underinvestment and is trying to attract private operators into joint ventures at some of its fields.

7.2.2 Reserves, Production, and Use

Petroleum is the basis for Ecuador's economy: exports account for around 20 percent of GDP and 45 percent of export earnings. In 2000, export earnings from the sale of 86.0 million barrels of crude and 15.8 million barrels of refined products reached US$2.4 billion.

Table 7.9 Oil and Gas Reserves of Ecuador, 1995–1999

Proven reserves	**1995**	**1996**	**1997**	**1998**	**1999**
Oil (million barrels)	3,385	3,453	374	4,102	4,428
Natural Gas (billion CF)	834	817	814	871	1,009
Reserves production potential (years)					
Oil	24	25	26	30	32
Natural Gas	23	25	25	25	30

Source: Ministry of Mines and Energy

Table 7.10 Petroleum Production & Consumption in Ecuador, 1990–2000 (thousand bpd)

	1992	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Production	325	354	375	402	406	394	380	378	399
Consumption	119	112	120	123	129	135	137	128	133

Most of Ecuador's crude production and proven oil reserves of 4.5 billion barrels are located in the Amazon basin (the Oriente). The majority of fields—representing around 55 percent of total production—are operated by Petroproducción.

In 1999 Ecuador began searching for private sector participation to improve recovery rates and boost production from a number of active fields. These included, initially, the two largest, Shushufindi and Sacha, and later the Auca, Lago Agrio, and Libertador fields. In 2001 Petroecuador tried unsuccessfully to establish operating alliances with foreign companies with a view to increasing production by 23,000 bpd by reopening 90 state oil company wells that were closed for budgetary reasons. Exploration rights for five marginal Amazonian oil fields that are currently shut down have been licensed. The Chananque, Ocano-Peña Blanca, Pacay, Puma, and Singue fields have an estimated total of 30 million barrels.

Table 7.11 Ecuador's Largest Oil Fields

Field	Average Output (BBLD)	API Gravity	Reserves (million BBL)
Shushufindi	90,000	31.2	665
Libertador	74,000	29.7	213
Sacha	71,000	26.8	311
Auca	41,000	27.0	164
Lago Agrio	14,000	n/a	n/a
Cononaco	10,000	23.0	35

Sources: DOE/EIA, PetroEcuador, and Platt's Oilgram News

7.2.3 Pipelines

Oil production in the Oriente, and thus Ecuador's oil exports, depend on the Trans-Ecuadorian Oil Pipeline (SOTE). It has a nominal capacity of 325,000 barrels per day and runs from the oil field of Lago Agrio to the oil terminal at the port of Esmeraldas. Although SOTE is capable of transporting oil of various gravities, heavier crudes must be diluted with lighter crudes to be transported, and the capacity limitation has lead to extraction rationing.

In 2001 the construction of the country's much anticipated heavy crude oil pipeline known as the OCP (Oleoducto de Crudo Pesado) was approved. The OCP, a proposed 503 km, 518,000 bpd capacity pipeline will carry oil with an average 18-degrees API (capable of transporting 18–24 degrees API oil) from ecologically sensitive areas in the Amazonian jungle across the Andean mountains to the port of Balao, near Esmeraldas, on the Pacific Ocean. The construction of the pipeline has spurred strong opposition from environmental groups because the pipeline and associated oil fields are located in fragile Amazonian ecosystems.

With OCP operational, Petroecuador will have surplus capacity in the SOTE pipeline, which will enable the private operators to increase production.

7.2.4 Refineries and Downstream Processing

Ecuador has a crude oil refining capacity of 176,000 barrels per day as of 2001. Refineries are located at Esmeraldas, La Libertad, and Shushufindi.

Table 7.12 Petroleum Refineries in Ecuador

Refinery	Capacity (bpd)
Esmeraldas	110,000
La Libertad	46,000
Shushufindi	20,000
Total	**176,000**

Source: Pennwell's *International Petroleum Encyclopedia*

7.2.5 Natural Gas, Associated Gas, and LPG

Proven natural gas reserves are estimated at 1,009 bcf. There is currently no natural gas market in Ecuador. The only major natural gas project in Ecuador is that of U.S.-based EDC, which was awarded a concession to explore Block 3 of the Amistad gas field in the Gulf of Guayaquil. The gas in the 346 bcf reserve will be transported onshore by pipeline to be used for electricity generation, displacing as much as 15,000 bpd of liquids burned by power companies and industrial customers.

Table 7.13 Ecuador's Production of Refined Petroleum Products in 2001 (MMB)

Product	**Refinery**			
	Esmeraldas	**La Libertad**	**Shushufindi**	**Total**
LPG	1.537	0.009	1.017	2.563
Gasoline Super*	3.798	n/a	n/a	3.798
Gasoline Extra*	5.220	0.732	0.183	6.134
Diesel 1	0.390	0.172	0.035	0.597
Diesel 2	8.025	3.480	1.507	13.013
Diesel Premium	0.539	n/a	n/a	0.539
Jet Fuel	1.117	0.555	0.100	1.771
Fuel Oil #4	3.979	8.431	n/a	12.411
Residuals	11.898	n/a	n/a	11.898
Asphalt	1.065	n/a	n/a	1.065
Spray Oil	n/a	0.065	n/a	0.065
Solvents	n/a	0.078	n/a	0.078
Total	**37.570**	**13.522**	**2.841**	**53.933**

7.2.5.1 Associated gas

The associated gas is flared, reinjected, or used to provide energy for the sector's own energy needs. A certain part is processed at the Shushufindi Refinery to produce LPG, natural gasoline, and residual gas.

According to the Ministry of Mines and Energy the total production of associated gas in 2001 was around 35 bcf, or 97 mmcfd. The largest part of the associated gas is produced by Petroproduccíon, with around 62 mmcfd, corresponding to 64 percent. The other large producers are the private companies Tecpecuador (14 percent), Occidental (6 percent), AEC (6 percent), and YPF/Repsol (5 percent).

Table 7.14 Associated Gas Use, 1999 (bcf)

Gross Production	38
Vented, Flared	28
Reinjected	6
Marketed Production	4

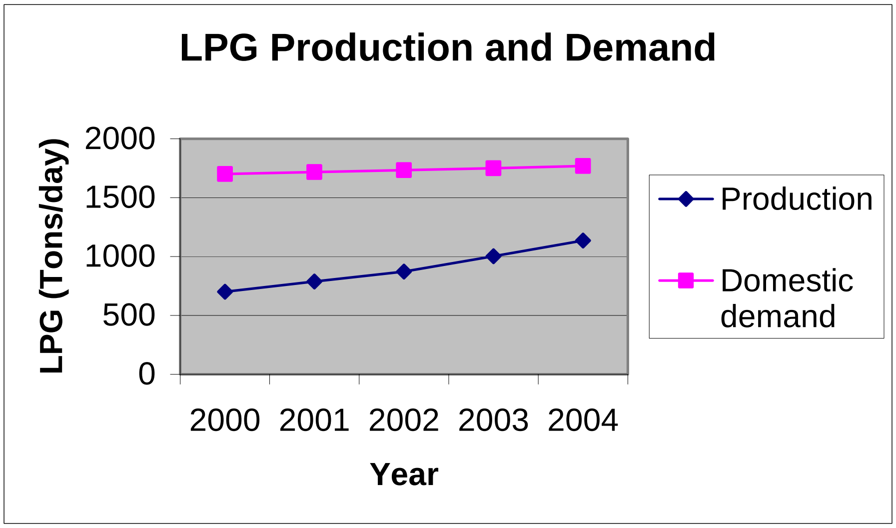
Source: EIA

7.2.5.2 Liquefied petroleum gas

LPG is a common cooking fuel, and large quantities are imported to meet demand. Current domestic production is around 800 t/d, about 60 percent of which is produced at Esmeraldas and the rest at Shushufindi. Approximately 1,100 t/d is imported to satisfy domestic demand.

LPG has been highly subsidized, and Ecuador is under pressure by IMF to reduce distorting subsidies. In 2001, the government published plans to double the price for households from US$1 per 15 kg cylinder. This was met with violent protests, and a compromise agreement was reached to set the price at US$1.60, or US$107 per ton, still highly subsidized and the lowest in Latin America. The "bono solidario" scheme compensates Ecuador's poorest families for the price increase. The domestic price is far below the 2001 import price at US$315 per ton. The domestic price does not even cover costs for storage, bottling, wholesale, and retail transport and distributor profits and thus represents a disincentive to Petroecuador to supply LPG. If increased domestic LPG production could be achieved at a lower cost than the present marginal costs (the import cost), however, then there would be a clear incentive for Petroecuador to try to minimize its losses through import substitution.

Figure 7.2 Domestic LPG Production and Demand, t/d



Source: Petroproducción

7.2.6 Gas Use in Production Fields

The map shown at the end of this report, shows the concession areas in the Amazon region and the fields under exploitation, either managed by Petroproducción or under concession to private companies**.** Petroproduccíon flares approximately 40 percent of the associated gas produced. The rest is treated at the Shushufindi gas plant (30 percent) or used for ancillary power on the production sites and other purposes (30 percent). Among the larger private companies, only Tecpecuador flares all their associated gas. Occidental, AEC, and YPF/Repsol are either reinjecting the gas or using it for ancillary power with very limited flaring.

7.2.7 Existing Plans to Reduce Gas Flaring

The existing projects outlined here are noted to highlight the way they complement those identified by the present study.

7.2.7.1 LPG plant at the Sacha field

In this project, a private operator would invest in an LPG production plant. The project will build a processing plant for associated gas and will produce dry gas, LPG, and natural gasoline to be sold to Petroecuador. The associated gas will be processed into LPG, dry gas, and natural gasoline, and the outputs will be delivered to Petroproducción and Petroindustrial. The LPG will be delivered through the Shushufindi-Quito Pipeline.

A project profile presented to the Bank, titled *Amazonía Pimee, Gas Processing Plant at Sacha Field*, notes that the Confederación de Nacionalidades Indígenas de la Amazonía Ecuatoriana (CONFENIAE), an organization representing 200,000 indigenous people, has the right to benefit from the associated gas from the Sacha field. Key players in the structuring of the proposal are the Canadian government and a Canadian oil and gas company owned by Canadian indigenous communities—the Keyano Pimee Exploration Company (KP). A parallel to the Canadian company, the Amazonía Gas (AG) has been set up by the Ecuadorian indigenous groups for the purpose of managing the project. A consortium between KP and AG is to construct and operate the plant and benefit from the revenues of the plant under a subcontracting agreement with the Canadian government, who will be the formal holders of the concession. At the end of the 12-year contract, the plant will be transferred to Petroindustrial.

The production of associated gas is currently around 9 mmcfd, of which the majority is flared and a small part is used as a nonrefined fuel by Petroproduccíon. The project is expected to consume 7.3 mmcfd of gas, 1.3 of which will be used as fuel in the gas processing plant. The remaining 6 mmcfd of gas will be used by Petroproducción to produce 80 tons of LPG and 30 tons of condensates per day. This LPG production corresponds to 10 percent of the current domestic production of LPG. The project includes an environmental management plan to protect the local environment and ensure social development benefits from the project. The project will sell its products to Petroecuador for less than the prevailing import price. The total investment would be about US$40 million.

7.2.7.2 Reinjection of associated gas at the Tecpecuador fields

Tecpecuador is active in the Bermejo Norte and the Bermejo Sur fields in the northwestern most part of the Oriente. Tecpecuador has a production-sharing agreement with Petroproducción. Bermejo Norte consists of nine active wells with an annual production of approximately 5.7 mmcfd of associated gas and Bermejo Sur consists of 20 active wells with an annual production of around 6.3 mmcfd of associated gas. This amounts to more than 14 percent of all the gas produced in the Oriente.

Today all gas produced in the two fields is flared. This is partly because of the high content of CO_2 in the gas from most of the wells. In 16 out of the 29 wells, the CO_2 content in the gas is higher than 50 percent. Tecpecuador, however, informed the team that they are considering a project for reinjection and use of their flare gas for ancillary power production (diesel substitution). It is the hope that flaring will be all but eliminated by 2004.

7.2.7.3 Recuperation of associated gas at Petroproducción fields

The following are the major fields where gas use projects are being implemented or where plans for doing so are in an advanced stage:

- **Aguarico/Secoya.** This project will capture 1.5 mmcfd of associated gas from Secoya and Aguarico. After compression, the gas will be transported to the processing plant at Shushufindi for LPG production or processed at a plant in Secoya. No plans have yet been made for the use of the dry gas after the LPG is taken out.
- **Atacapi-Parahuacu.** This project will capture flared gas from the Atacapi-Parahuacu fields. The first phase, currently under implementation, will capture 3.0 mmcfd. A second phase that is being planned will capture another 3.0 mmcfd. After compression, the gas will be transported to the processing plant at Shushufindi for LPG production. No plans have yet been made for the use of the dry gas after the LPG is taken out.
- **Shushufindi.** This project, under implementation, will capture 3.0 mmcfd.
- **Guanta, Pichincha, and Yuca.** Projects planned for these fields will capture 3.1 mmcfd.
- Ten planned Petroproducción wells will generate a total of 3.1 mmcfd**.**

In summary, projects using around 16 mmcfd are in various stages of development.

7.3 Options to Reduce Gas Flaring

A few pilot projects to reduce gas flaring have been identified on the basis of the following criteria:

- Yield—fields with adequate gas quantities and composition- or energy-content ratios.
- Added value—priority has been given to fields where gas use projects are not already planned.
- Availability of data—only sites for which adequate data exists have been considered. Once additional data becomes available, the Auca and Lago Agrio fields also should be analyzed.

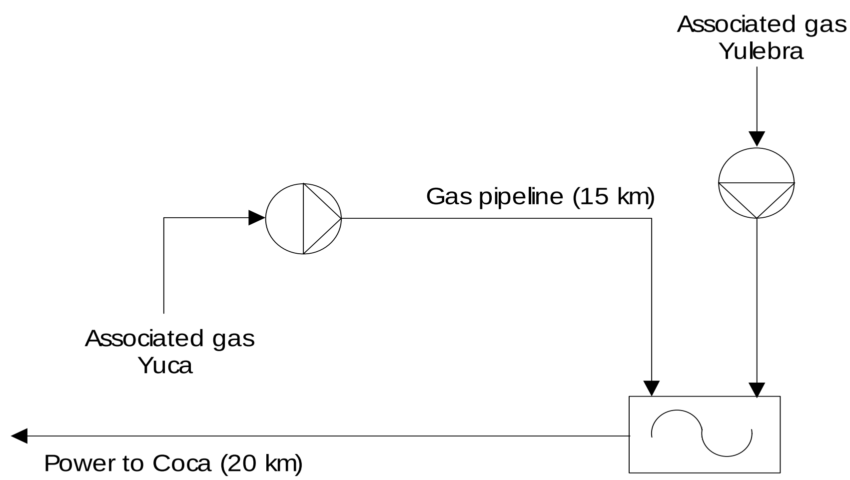
On the basis of these criteria, the Yuca and Yulebra fields have been selected as the most promising for gas use pilot projects. They are situated southeast of Coca at a distance of approximately 35 and 15 km, respectively, and the distance to Shushufindi in the north is approximately 100 km. The Yuca field is the largest in terms of associated gas produced, but the smaller Yulebra field is closer to Coca, resulting in lower delivery costs.

7.3.1 Project Alternatives

Three different associated gas use alternatives have been evaluated:

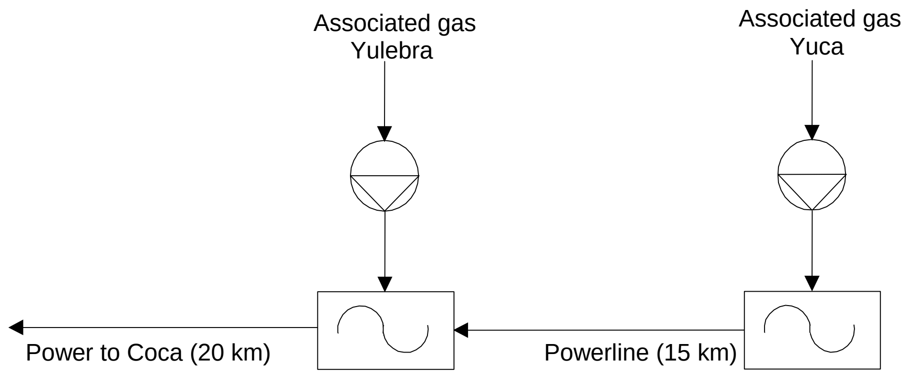
- *Alternative 1:* This alternative includes compression and transportation of associated gas from Yuca to the Yulebra site, where it is mixed with the compressed associated gas from Yulebra. The compressed gas from the two fields is used to generate power, and the generated power is transported via a new transmission line to the Coca grid. Here, the gas from Yuca would be compressed to approximately 20 bar and piped 15 km to be mixed with the compressed gas from the Yulebra field. It has been estimated that it is not likely to be a problem to transport the Yuca gas, despite its relatively high content of heavy hydrocarbons.

Figure 7.3 Alternative 1—Power Production at the Yulebra Site



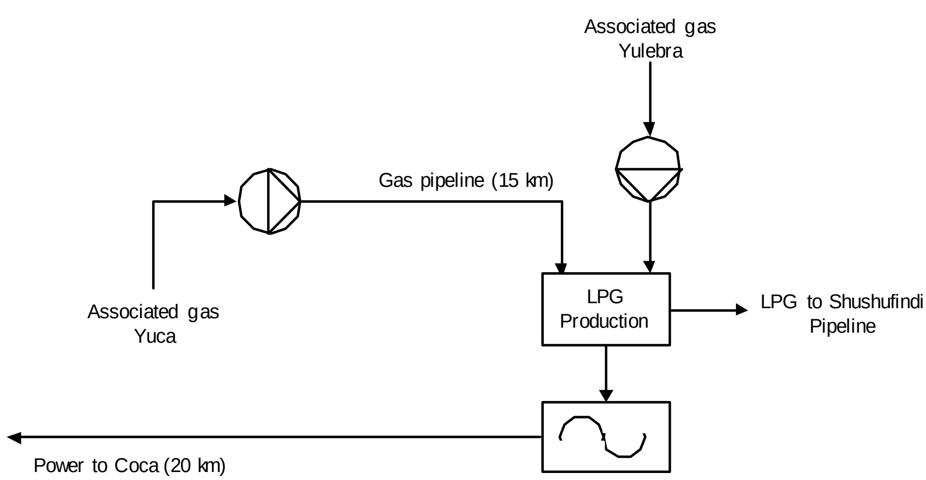
- *Alternative 2:* This alternative includes compression of associated gas and power generation both at the Yulebra and Yuca sites. The power produced at Yuca is transported to the Yulebra site in a new transmission line, where the power production from both sites is transported—also through a new transmission line—to the Coca grid.

Figure 7.4 Alternative 2—Power Production at Both Yuca and Yulebra Sites



- *Alternative 3 (Alternative 1 plus LPG):* A variation of Alternative 1 is that LPG is produced at the Yulebra site using gas from both fields. The remaining gas can be used afterward for power production as in Alternative 1.[38]

Figure 7.5 Alternative 3—LPG and Power Production at the Yulebra Site



[38] Another variation of this alternative could be to produce nondistilled liquids in road tankers to the refinery in Shushufindi. Provided there are customers for bottled gas in the southern part of the country, this solution would add to transportation costs without saving much on equipment, so it is therefore assumed that this option can be disregarded.

7.3.1.1 Possibility to absorb the produced power in the grid

The maximum demand in the Sucumbíos grid is at present around 20 MW according to information supplied by the Empresa Electrica Sucumbíos S.A. (EES). The minimum load is assumed to be in the order of 6–7 MW, but firm figures were not available on this issue. Given this minimum load and the existence of a medium voltage network interconnecting Coca with Nueva Loja and Shushufindi, it can be assumed that the EES grid can absorb the 4 MW of continuously produced power sent to Coca from Yuca/Yulebra. This assumption would need to be checked, however, as would the technical options for connecting to the existing substation in Coca, during a detailed feasibility study to ensure accurate dimensioning of the gas use scheme.

7.3.1.2 Institutional aspects of supplying power to EES

The issue of selling power from Petroproducción to EES has been discussed with Petroproducción, the Ministry of Mines and Energy, and CONELEC. Whereas, in principle, everybody supports the idea, arriving at a viable setup could take time (because of, for example, defining terms for a power purchase agreement stipulating the sales price, the responsibilities of undertaking the different necessary investments, operation and maintenance of the installations, as well as the conditions of supply).

7.3.1.3 Equipment for gas treatment

In all the described cases, compression of the gas at the field is the first processing step and power generation the last step. At Yulebra the 406,000 standard cubic feet per day (13,600 m^3/d) of gas is compressed, and at Yuca, a compressor station for 855,000 standard cubic feet per day (26,300 m^3/d) is needed.

In Alternative 1, a new gas pipeline will transport the gas stream from Yuca to the power generation plant in Yulebra.

In Alternative 3 (Alternative 1 plus LPG), the combined gas stream from Yuca and Yulebra of 39,900 m^3/d (approximately 35 t/d) must undergo the following treatment steps:

- dehydration
- chilling
- distillation, storage, and transport to the Shushufindi LPG pipeline

The result is that a maximum of approximately 14 percent of the gas weight may be converted into around 4,300 kg LPG per day. The remaining 86 percent of the gas will be used for power production. The LPG constitutes 9 percent of the volume of the associated gas.

7.3.1.4 Equipment for power production

In Alternative 1, a 7 MW gas generation plant at the Yulebra field is needed, and a power transmission line from Yulebra to Coca with a capacity of 4 MW will have to be constructed.

In Alternative 2, two gas generation plants will be needed, one of 2 MW at Yulebra and one of 5 MW at the Yuca site. Furthermore, a power transmission line from Yuca to Yulebra with 2.75 MW of capacity and a power transmission line from Yulebra to Coca with a capacity of 4.2 MW will have to be constructed.

In Alternative 3, the gas to be used for power production is reduced because of the LPG extraction, the generation capacity needed is reduced to 6 MW, and the transmission capacity is reduced to 2.6 MW.

7.3.2 Associated Gas, Power, and LPG Production

In the table below, the annual associated gas production from the two oil fields are shown together with the present annual electricity consumption—currently based on diesel—of each oil field.

Table 7.15 Annual Associated Gas Production and Electricity Consumption at Yuca and Yulebra (2001)

	Yuca	Yulebra
Production of Associated Gas (million m^3)	8.8	4.5
Electricity Consumption (MWh)	6,953	3,043

On the basis of the above figures, the total amount of electricity for gas compression and sales to the grid in Coca can be calculated for each of the three alternatives. The electricity production decreases from 34,853 MWh to 22,624 MWh if LPG is produced from the associated gas and the rest is used for power production.

In Alternative 1 and Alternative 2, the power export to Coca is nearly the same. The small difference is from the increased amount of electricity used to compress the gas that has to be transported, compared with the situation where the gas can be used directly for power production.

The volume of the LPG production corresponds to 11.3 percent of the associated gas in Yuca and 4.5 percent of the associated gas in Yulebra. The Yuca gas is seen to be richer (that is, with more LPG potential than the Yulebra gas); this illustrates the difference in content of the gas from field to field (and often from well to well) in the Oriente.

Table 7.16 Annual Electricity Production and Use, MWh (2004–2015)

	Yuca	Yulebra	Total
Production of associated gas (million m^3)	8.8	4.5	13.3
Alternative 1—Generation at Yulebra			
Total electricity production	13,911	40,594	54,505
Electricity consumption at site	6,953	3,043	9,996
Electricity consumption for compression	6,958	2,698	9,656
Electricity exports	0	34,853	34,853
Total export of electricity to Coca			**34,853**
Alternative 2—Generation at both sites			
Total electricity production	36,218	18,287	54,505
Electricity consumption at site	6,953	3,043	9,996
Electricity consumption for compression	5,218	2,698	7.916
Electricty exports	24,047	12,546	36,593
Total export of electricity to Coca			**36,593**
Alternative 3			
Recovery of LPG (million m^3)	1.0	0.2	1.2
Net gas production (million m^3)	7.8	4.3	12.1
Total electricity production	26,519	15,757	42,276
Electricity consumption at site	6,953	3,043	9,996
Electricity consumption for compression	6,958	2,698	9,656
Electricity exports	12,608	10,016	22,624
Total export of electricity to Coca			**22,624**

Table 7.17 Annual LPG Production from Yuca and Yulebra Gas (2004–2015)

	Yuca	**Yulebra**
Production of Associated Gas (million m^3)	8.8	4.5
LPG production (million m^3)	1.0	0.2
LPG production (ton)	2,102	549

7.3.3 Economic Evaluation

An economic cost-benefit analysis showing the project economy from the viewpoint of society has been carried out. The economic analysis is based on assessment of benefits and costs of the three projects.

7.3.3.1 Project boundary

The "Making Use of Flared Natural Gas Project" is considered incremental to an existing oil development project, so only the incremental costs and benefits need be considered.

7.3.3.2 Calculation of economic viability

The determination of economic and financial feasibility is based on the net present value (NPV) of the cash flow for a specific period.

7.3.3.3 Calculation period

The production horizon of the Yuca and Yulebra fields are assumed to be at least 15 years. Hence, a calculation period of 15 years of operation has been used.

7.3.3.4 Economic and financial discount rates

The real discount rate for projects in emerging economies is country specific and normally is given by the local planning agency or the Ministry of Finance. The Bank generally estimates the economic discounting rate to be between 10 and 12 percent per year in emerging economies. A rate of 12 percent per year has been used in the present calculations.

The financial discounting rate often varies over a wider interval and depends on the general profit expectations versus the perceived risks in the specific sector and country. In this project it has been agreed to use 15 percent as the financial discounting rate in the base case.

7.3.3.5 Currency

All calculations have been made in U.S. dollars, which is the standard currency for the international oil sector.

7.3.3.6 Prices and inflation

Calculations have been fixed at 2002 price levels.

7.3.3.7 Economic fuel cost

The economic cost of fuels in Ecuador is the current import and own production prices excluding taxes. The cost of diesel in Yuca, Yulebra, and Coca is the export price less transport from Shushufindi, plus the cost of transportation to the various sites. These costs have been obtained from Petroproducción.

LPG consumption in Ecuador exceeds the domestic production. LPG value is set to the import price. The import price—average year 2001—has been obtained through Petroecuador.

The cost of associated gas at the wellhead is set to zero, and the economic cost of flaring to US$20 per ton CO_2, a typical international rate for CO_2 emissions. The amount of CO_2 in the flared gas is estimated at 2.9 tons of CO_2 per 1000 m^3 of gas in Yuca and 2.7 tons of CO_2 per 1000 m^3 of gas in Yulebra.

The economic benefit of swapping diesel-based power production with gas-based power production is quantified as the difference in CO_2 emissions from gas and diesel, respectively. It has been assumed that there will be 20 percent extra CO_2 emission per kilowatt-hour based on diesel compared with a kilowatt-hour based on gas.

7.3.3.8 Investment costs

The investment cost for each alternative has been estimated on the basis of key figures. In all alternatives, compression of the gas at the field is the first step and power generation the last step. The compression station at Yulebra is estimated to cost US$0.8 million and US$1.2 million at Yuca.

In Alternative 1 and Alternative 3, gas pipeline costs (US$0.7 million) are accounted for before calculating benefits from power generation.

Table 7.18 Economic Fuel Costs (2001)

	Unit	**US$**
Diesel—Yuca	Gallon	0.813
Diesel—Yulebra	Gallon	0.807
Diesel—Coca	Gallon	0.778
LPG—net back Shushufindi	ton	315
Cost of gas for power production	ton	0
Cost of flaring associated gas	ton CO_2	20
Emission reduction from gas-based power production compared with diesel-based		+20%
Emission reduction from gas-based power production compared with HFO-based		+30%

The investment cost for the LPG alternative is estimated at the following:

- Dehydration at a cost of US$1.7 million
- Chilling at a cost of US$0.7 million
- Distillation, storage, and distribution at a cost of US$0.5 million

The power generation plants and transmission lines are estimated as shown below, as are the investments needed for each alternative.

7.3.3.9 Operation and management (O&M) costs

The annual O&M cost has been estimated at 2 percent in Alternative 1 and 2 and 5 percent in the LPG alternative of the investment costs.

Table 7.19 Investment Cost, US$ million

	Alternative 1	**Alternative 3 (Alternative 1 plus LPG)**	**Alternative 2**
Compressor station Yuca	1.2	1.2	1.2
Compressor station Yulebra	0.8	0.8	0.8
Gas pipeline Yulebra-Yuca	0.3	0.3	–
Gas generation plant 7 MW	4.3	–	–
Gas generation plant 6 MW	–	3.7	–
Gas generation plant 5 MW	–	–	3.3
Gas generation plant 2 MW	–	–	2.1
Power transmission lines	0.4	0.4	1.0
Dehydration of gas	–	1.7	–
Chilling of gas	–	0.7	–
Distillation, storage, and so forth	–	0.5	–
Total	**7.0**	**9.3**	**8.4**

7.3.3.10 Result of economic analyses

The result of the economic analyses is presented as the NPV of net benefits (using an economic discounting rate of 12 percent in the base case) as well as the economic internal rate of return (EIRR).

The results are presented at a value of US$0 and US$20 per ton of CO_2. In the latter case, the value of CO_2 at which the net benefit will be zero is calculated—this value is also referred to as the abatement cost. The negative abatement costs illustrate that the project is economically feasible without internalizing the value of CO_2 reductions.

Table 7.20 Economic Analyses Results, US$20 per ton CO_2

NPV million US$	**Benefits**	**Costs**	**Net Benefits**	**Gas Flared %**	**EIRR %**
Alternative 1	24.7	7.0	17.7	0	57
Alternative 2	25.5	8.1	17.4	0	50
Alternative 3	24.6	11.0	13.6	0	39

Table 7.21 Economic Analyses Results, US$0 per ton CO_2

NPV million US$	**Benefits**	**Costs**	**Net Benefits**	**EIRR %**	**Abatement costs US$/ton**
Alternative 1	19.2	7.0	12.2	43	-46
Alternative 2	20.0	8.1	11.9	39	-45
Alternative 3	19.1	11.0	8.1	29	-31

7.3.4 Financial Analysis

The following is a financial analysis from the point of view of the field operator (Petroproducción). It is not a real financial cash-flow analysis and does not include depreciations and taxes, that is, it only considers real revenues experienced by the state-owned operator, Petroproducción. Furthermore, it is assumed that power can be sold to the Sucumbíos grid at a price that would be equivalent to the price of diesel-based power. A financial discounting rate of 15 percent has been used.

Table 7.22 Financial Analysis Results

NPV million US$	Income	Costs	Net Income	Gas Flared %	FIRR* %
Alternative 1	16.1	6.7	9.3	0	43
Alternative 2	16.7	7.7	9.0	0	39
Alternative 3	16.0	10.3	5.7	0	29

* Financial internal rate of return

The results indicate that the project is likely to create significant net benefits and an attractive financial internal rate of return (FIRR).

In reality, this net benefit will have to be distributed between the field operator and the power company following negotiations of a power purchase agreement. This result indicates, however, that the benefits are large enough to reduce gas flaring profitably, that is, it is a win-win outcome.

7.3.5 Sensitivity Tests

A number of sensitivity tests have been carried out. They include decreasing all energy prices by 20 percent, increasing all investments by 20 percent, and increasing the discounting rates (both economic and financial) by 10 percentage points (for example, from 12 to 22 percent). Furthermore, the hitherto autonomous Sucumbíos grid is in the process of being interconnected with the national grid. This will change the economics of the project somewhat because the gas-based electricity will no longer only replace diesel. The consequences of this are that the project will replace cheaper fuels used in the national system. In a sensitivity analysis, the replaced fuel is assumed to be heavy fuel oil (HFO) at approximately half the price of diesel.

Table 7.23 summarizes the results of these sensitivity tests by comparing the net benefits at a cost of US$0 per ton CO_2 as well as the balance CO_2 abatement costs and the financial internal rate of return of the base case and the sensitivity cases. The results are only presented for Alternative 1, which remains the most viable no matter which combination of sensitivities is tested.

Table 7.23 Sensitivity Tests Results —Alternative1 at US$0 per ton CO_2

NPV million US$	Base Case	Energy Prices +20%	Investments +20%	Discounting rates +10%	Substitution of HFO
Net Benefit, million US$	12.2	8.3	10.7	5.0	5.4
Abatement Cost, US$/ton	-46	-32	-41	-19	-20
FIRR %	43	34	35	43	26

7.3.6 Social Benefits

Social benefits for the population in the area will materialize when the local power company is able to benefit from the gas-flaring scheme allowing them to cut costs and provide a more stable supply. In the short run, this may not actually result in lowering power prices but rather in filling existing gaps between revenues and costs brought about by artificially low tariffs, power theft, and poor payment discipline. In the longer term, however, such cost cuts will provide the basis for sustainable operation and possibly also an extension of the coverage, that is, more households will be connected.

7.4 Ecuador Conclusions

The results of the analyses show that both at zero cost of CO_2 and a cost of US$20 per ton of CO_2, all three alternatives are more viable economically than the continued flaring option. Alternatives 1 and 2, however, have a higher EIRR than Alternative 1 including LPG production (Alternative 3). The picture is the same in the financial analysis.

The main conclusions are:

- Power production at the Yulebra site using the associated gas from both the Yuca and Yulebra fields is viable from both a financial and an economic point of view.
- The pilot project would offer a win-win situation whereby the operator cuts his operational costs and the Sucumbíos grid cuts its fuel expenses, provided a reasonable power purchase agreement can be negotiated between Petroproducción and the power company and a proper fiscal regime is put in place.
- By reducing the cost of power production in the Sucumbíos grid the project can lead to lower power tariffs and create a financially sustainable basis for expanding the power supply.

Project-specific conclusions are the following:

- With the recent incorporation of the Sucumbíos grid to the national grid, other similar projects can be undertaken in many of the Oriente oil fields (both those operated by Petroproducción and private companies); the limiting factor will be transmission capacity.
- In the longer term, the savings from the proposed flaring reduction will provide the basis for sustainable operation and possibly also an extension of the coverage in the Sucumbíos grid, that is, more households will be connected.
- Small-scale LPG production is not feasible because of economies of scale. It may be financially viable, however, to collect gas from several fields and treat this in a central processing facility at a cost competitive to the cost of importing LPG.
- The project will be replicable in other countries, but the constraint in sparsely populated areas will be the low load absorption capability.

Finally, the following conclusions can be made on a general level for small-scale use of flare gas:

- The Yuca-Yulebra project shows that the elimination of flaring can be sustainably achieved, that is, it can be achieved with social, economic, and environmental benefits.
- In a developing country context, small projects will be constrained by the lack of market (if the interconnection to the national grid had not been built, only a small fraction of the flared gas in the Oriente could be used for power production because demand is low).
- Financial incentives will not always be as high as economic incentives, since financial and economic benefits are not at the same level; this could be addressed through country strategies and governmental action plans.
- The value of good-faith industry commitment to social and environmental concerns is noteworthy on humanitarian and business grounds. Highlighting innovative initiatives (for example, with specific goals and monitoring and reporting provisions) through formal "voluntary agreements" between the public and private sectors as well as final beneficiaries could help stimulate interest and promote innovation.

7.5 Ecuador Recommendations

Capacity building on gas use possibilities should be introduced to facilitate partnerships between state-owned national oil companies and the private sector. The government of Ecuador should encourage the oil and power companies to cooperate to ensure that Ecuador obtains the benefits available from the project. The government could, for example, facilitate the implementation of the analyzed projects by arranging any needed concessions in the fiscal regime.

- The government of Ecuador should form a special working group to encourage this and other small gas developments, ensuring that any required authorizations, special agreements, or cooperation between the oil and power companies are facilitated to ensure Ecuador captures the benefits available from small gas developments.
- The baseline data on the continuous diesel-fired load of the power company should be confirmed to ensure that the power generated can indeed be absorbed, thereby assuring the expected economic benefits.

A followup study should be completed to determine how the project might best be structured commercially to ensure its implementation (for example, by recommending best practices to project participants). As a first step of such a project, the Ministry of Mines and Energy should prepare a detailed gas use strategy in which gas use options from Petroproducción fields as well as from privately operated fields are analyzed to determine the need for common transport, processing, and power generation facilities and to benefit from any economy of scale that may arise. In this context the possibilities for increased LPG production should be assessed.

8 Mozambique's Vilankulo Gas Pilot Project—Ten Years of Benefits

In 1992, an exploration well in Mozambique's Pande (nonassociated) gas field was put in production to supply gas to power generation facilities in Vilankulo, a town of more than 25,000 inhabitants. At a cost of US$1.3 million, the initial project included wellhead gas processing, a 105 km polyethylene transmission pipeline, and a single 135 kVA generator set. Since 1992, the system has been expanded several times and gas is now also supplied to the nearby towns of Inhassoro and Nova Mambone, and to the coastal islands of Magarugue, Benguerra, and Bazaruto. In addition to use in power generation, natural gas also supplies commercial concerns and some residential customers, for example, the facilities of the Empresa Nacional de Hidrocarbonetos de Mocambique (ENH—the national oil company of Mozambique); government and commercial users in Vilankulo, including the hospital; hotels and restaurants; local merchants and small manufacturers; and to some wealthy local residents who use it for cooking and private power generation.

The Vilankulo Gas Pilot Project is clearly a local success story, as confirmed by the ongoing expansions of the system. But, the benefits have not ended there. Much of the institutional gas capacity in ENH and the Mozambican government is the result of skills and experience gained from the Vilankulo Gas Pilot Project. The availability of this institutional capacity was a key factor in the conclusion of a gas export deal between Mozambique and South Africa's Sasol that will see large-scale gas exports from Mozambique to South Africa. The gas exports will dramatically increase Mozambique's foreign exchange earnings and GNP, reducing the level of poverty in the country and accelerating its overall development.

8.1 Background

8.1.1 Energy Supply

Many rural towns and villages in Mozambique lie distant from main centers and retain only limited access to energy for development. Although Mozambique generates considerable hydropower (the bulk of which is sold to South Africa), electricity from the grid is not available in Inhambane Province, where the Vilankulo Gas Pilot Project is located, because of the high cost of the equipment and facilities needed to bring electricity into the area.

When the Vilankulo Gas Pilot Project was being developed in 1991, the fuelwood supply in the area around Vilankulo was becoming a concern, as the area is predominantly savannah with poor forest resources. In addition, there were acute shortages of other forms of commercial energy due to foreign exchange shortages and supply disruptions from a civil war. The only other possible energy source in the area was nonassociated natural gas.

Two significant gas discoveries in the Vilankulo area, the Pande and Temane gas fields, were the result of oil exploration efforts by Gulf and Amoco in the 1960s. Efforts were made to develop uses for the gas, without success, until the area was abandoned in 1974. Interest in the Pande field, 105 km Northeast of Vilankulo, was renewed in the 1980s and ENH conducted successful drilling activities in the Pande field in 1989 and 1990, proving a large reserve of sweet, dry natural gas.

8.1.2 Energy Demand

In Vilankulo in 1991, there was a large unsatisfied demand for energy, particularly for electricity. However, high fuel prices and chronic fuel and parts shortages, partially from the effects of a civil war, severely limited the availability of energy, particularly locally generated electricity. Government-owned diesel generation equipment in Vilankulo was no longer serviceable. Other small diesel- and gasoline-fired generators in the area were operated only intermittently when fuel was available.

8.2 The Project

With the development of an exploration well in the Pande field, an affordable, reliable supply of energy for Vilankulo and the surrounding area finally became available. Using predominantly local labor and resources, ENH constructed a small wellhead gas processing plant at the Pande gas field and a new 135 kVA, gas-fueled, generator set in Vilankulo, connecting the two with a 105 km, 75mm diameter low-cost polyethylene pipeline and installation of a low-cost pressure reducing station. Since coming onstream in 1992, the project has been in continuous operation and the system has been expanded several times. A summary of the scope and costs of the Vilankulo Gas Pilot Project and its subsequent expansions is presented in Table 8.1.

Extension projects undertaken by ENH have included the expansion of the gas distribution network and power generation facilities in Vilankulo, and the installation of lateral pipelines and power generation facilities to make Pande gas available in the nearby communities of Inhassoro and Nova Mambone.

Initially constructed and commissioned by Flour South Africa, in 1999, Elgas, another South African company, became involved in the expansion of the gas supply network. In 2001, Elgas, with ENH, installed two short subsea pipelines and several gas-fueled generator sets making gas and electricity available on the nearby coastal islands of Magaruque, Benguerra, and Bazaruto.

As demonstrated by the ongoing expansion activity, the Vilankulo Gas Pilot Project is a very successful enterprise. In addition, direct benefits from the availability of affordable, reliable, natural gas as an energy source in the project area, the pilot project can be credited with contributing significantly to the development of Mozambique's economy.

Mozambican nationals under the guidance of Flour South Africa carried out the majority of the work on the project and its expansions, providing these persons with practical skills in gas contracting, the design, construction, and operation of natural gas systems and power generation facilities. This experience has in turn resulted in the establishment of significant institutional capacity within ENH and the Mozambican Government.

The depth of gas industry expertise available within ENH and the government was a key contributing factor in the successful negotiation of a major natural gas export contract with South Africa's Sasol in the last quarter of 2000. Drilling, facilities installation, and pipeline construction activities are currently in progress. For at least the next two decades, revenues from export gas sales and taxes on Mozambican gas production and pipeline operations will provide large amounts of foreign exchange earnings and tax revenues, significantly increasing Mozambique's GNP. Clearly, small projects can lead to follow-on development benefits.

The overall characteristics of the project, paid within the US$1.3 million budget initially foreseen for the project are:

- A gas treatment plant for the wellhead to dehydrate, eliminate condensates, and reduce pressure.
- HDPE pipeline to Vilankulo from Pande—105 km of 75 mm.
- A gas-fired (reciprocating engine) power plant in Vilankulo, inititally 220 kW and later expanded to 2 MW on the same basic gas supply design; this is because of the remarkably good flow characteristics of the polyethylene (HDPE) piping system.
- The gas system operates at 10 bar gauge pressure for the mainline system and reduces to 1 bar for local distribution to groups of houses. At the houses, the pressure is reduced to the low pressure needed for appliances (150 mbar).
- The cost of electrical power has reduced (although the tariff has increased well in access of costs).

On the consumer side, the following was achieved:

- Twenty houses of company employees were connected on a trial installation at a cost of US$150 per house; present cost estimates would be about US$250 per house covering costs from the ring-main to the burner-tip.
- Gas supply to individual houses can be supplied with a base tariff of US$17/month (this is for the affluent citizens, as average income for the poor is US$20/month).

8.3 Lessons Learned

While the Vilankulo Gas Pilot Project is supplied by a single gas well producing sweet, dry, nonassociated gas, the project illustrates clearly the potential for small-scale local uses of natural gas wherever gas is available. Gas transmission pipelines, in particular, are a logical source of supply for small gas projects. Mozambique is already thinking in these terms, considering how to make use of the export pipeline as a source of supply for small projects along the pipeline route. One of the first projects under development is expected to be a pipeline lateral from the new export pipeline to the capital city of Maputo.

The Vilankulo Gas Pilot project points to the following key requirements for successful development of economic small-scale projects:

- Cost-reduction through simplification at the installation of the gas system, using cheap elements such as HDPE piping, pressure-reducing-units, and other installations.
- Availability of a wholesale-priced natural gas supply.
- Access to gas transportation in major pipelines at the same prices as large users (if pipelines will be the gas source for small projects).
- Inexpensive access to pipeline right of way for small-scale pipelines.

- Access to technology and expertise (appropriate technology for the local situation and the local skills—minimal use of expensive outside experts and services. In Mozambique use of low-pressure polyethylene pipe technology was particularly helpful as skilled labor [like welders] is not required for installation and repair).
- Availability of financing for new projects and for customer fuel conversion equipment.
- Tax or other incentives to motivate customers to convert to gas.

Overall, therefore, it should be possible to replicate this kind of project elsewhere, though this is likely to require both some government involvement, as well as the focused delivery of the appropriate technology and practical know how.

Table 8.1 Vilankulo Gas Pilot Project—Summary Information

Activity	Description Vilankulo Gas Pilot Project (1992)	Local currency equivalent US$ (000’s)	Foreign Exchange US$ (000’s)	Total US$ (000’s)
Capital Cost				1225.0
EPC Services	Engineering, supervision, construction, and commissioning assistance (from South African contractor)		60.4	
Well Preparation	Remove cement plug and install production tubing	13.8		
Wellhead Gas Treatment	6000 m^3/day capacity, glycol dehydration, liquids separation, pressure regulation, and odorization		41.0	
Pipe	105 km of 5mm polyethylene pipe (including valves, fittings and construction accessories), 700 kPa operating pressure		821.4	
Power Plant	135 kVA, 400/230 volt, 50 Hz, generator set – containerized, with space and instrumentation for addition of second 135 kVA unit		171.4	
Pipe Laying and Equipment Installation	Operating labor, glycol, and odorant	27.5	89.7	
Operating Cost (annual)	Operating labor, glycol, and odorant	10.0*		10.0
Finance	Foreign currency component financed by NORAD, local currency component financed by ENH (national oil company of Mozambique)			
Expansion Projects				
Vilankulo Generation (1995)	135 kVA Caterpillar power plant in Vilankulo			150.0*
Inhassoro Extension (1995)	Lateral pipeline to Inhassoro—14 km of 75mm and 65 mm polyethylene pipe, and Caterpillar 135 kVA generator set			400.0
Vilankulo Generation	Three 110 kVA Perkins generator sets in Vilankulo			400.0*
Inhassoro Generation	Three 110 kVA Perkins generator sets in Inhassoro			400.0*
Vilankulo Gas Expansion (1998/99)	Expansion of natural gas network in Vilankulo to supply ENH houses, private houses, hotels and other commercial customers			200.0
Nova Mambone Expansion (1998/99)	Lateral pipeline to Nova Mambone—65 km of 65 mm polyethylene pipe, two 150 kVA gen-sets			1100.00*
Vilankulo and Offshore Islands Expansion (2001)	Lateral pipelines from Inhassoro and Vilankulo to offshore islands of Magaruque, Benguerra and Bazaruto—80 km of offshore 65mm polyethylene pipe, 500 kVa of generation on the islands, 450 kVa of generation in Vilankulo			2500.0* *estimates

9 Main Findings

The study has identified a number of realistic options for small-scale usage of flare gas. The opportunities have been evaluated on the basis of:

- Two cases studies, Ecuador and Chad
- The lessons learned from a nonassociated gas distribution project in Mozambique
- Financial and economic modeling

The following sections summarize the findings.

9.1 Findings from Case Studies

The Ecuador and the Chad case studies illustrate that small-scale/medium-scale use of flare gas can add important environmental, social, and wider developmental benefits to a developing country oil project without jeopardizing the economic or financial viability. The main feasible end-use options are power supply from generators at the oil field or gas supply via pipeline to a load center for fuel substitution in power production and local industries.

Dry flare gas being offered to industrial consumers at a price equivalent to or lower than the cheapest alternative fuel opens up interesting possibilities. In many oil-producing developing countries in Africa and South America, local industry is very underdeveloped, in part because of high fuel prices and the unreliable supply. Experience from all over the world shows that once a cheap and reliable fuel source, like natural gas, is available a number of industries, both small and large, will be attracted and the ensuing import substitution will give higher value added (and thus higher employment) in the country.

The Vilankulo Gas Pilot Project (even though based on supply of nonassociated gas) illustrates clearly the potential for small-scale local uses of natural gas wherever a gas supply source is available. In particular, gas transmission pipelines are a logical source of supply for small gas projects. Overall, it should be possible to replicate this kind of project elsewhere, though this is likely to require some involvement by the national government and the focused delivery of appropriate technology and practical expertise.

9.2 Findings from Economic and Financial Modeling

Economic and financial model analyses based on realistic assumptions from the analyzed case studies clearly indicate that flaring reduction is a win-win option in most cases. Subsidies are not needed—companies, governments, consumers and the environment all stand to gain.

The exceptions are where markets are far away (for a medium-size oil field it will be feasible to move the gas or power over 500 km in order to get to a market), or gas deposits are small (model calculations indicate that gas utilization from oil fields with gas yields over 2,500–5,000 m^3 per day can be viable when near potential markets) or where prices are distorted by domestic fuel subsidies.

There is little economic difference between transporting gas in pipelines to an industrial gas customer or an existing power plant on the one hand and power generation at the site and then transmission of by way of power lines to the load center on the other. The choice of technical solution will then be dependent on whether or not there will be other applications for the gas other than power production at the load center (for example, industrial enduse).

LPG use becomes economically advantageous at LPG prices (world market) over US$300 per ton provided that the content of LPG in the raw flare gas is over 15 percent or when the gas yield from the field is higher than 60,000 m^3/d.

9.3 Key Constraints for Small-Scale Gas Use

The key constraints for small-scale gas usage have been identified as follows:

- State-owned oil and gas monopolies lack incentives to reduce flaring and invest in alternative utilizations of the associated gas.
- National power markets are monopolized and power prices are often below real costs.
- Insufficient financial incentives.
- Imported LPG subsidies.

9.3.1 LPG Subsidies

In many countries, the present policy of subsidizing imported LPG inhibits domestic associated gas use. In the event of increased LPG consumption the governments may not be able to continue to fund LPG subsidies at the present level. The high subsidies on imported LPG are also unwise if LPG recovered from domestic associated gas is actually a better economic option. However, local demand for LPG may decrease once subsidies are reduced which has to be taken into account when assessing the viability of an LPG utilization scheme.

9.3.2 National Power Markets

In many developing countries (especially in Africa), national power markets are monopolized (even though in many places reforms are under consideration) and electrical power prices in rural grids are often below real costs. This can be a serious constraint on gas usage since the existing monopolies may lack the will and incentive to accept power from independent power producers (IPPs) and may be unwilling to convert their existing facilities to gas (diesel supply to isolated grids is a lucrative trade in many places). In addition to this, the artificially low prices created through cross-subsidization between urban and rural areas may constrain the financial viability of new electrification schemes. Low institutional and financial capacity to expand the power supply may constrain demand growth and delay the implementation of flaring reduction projects as well as impact negatively on the project economics.

9.3.3 Insufficient Financial Incentives

In spite of good project economics, the financial gains can sometimes be perceived as marginal given the risk profile in the countries in question and will often not satisfy the short payback times and the low-risk required by private investors. It is likely that neither a state-owned oil company nor private interests will be interested in implementing flaring reduction projects unless given extra incentives (or unless gas flaring is penalized). In many cases flaring reduction projects will need concessional financing to be attractive.

9.3.4 State-Owned Oil and Gas Monopolies

In several of the surveyed countries, it is still state-owned monopolies or quasi-monopolies that own and operate the oil and gas production and transport facilities. These monopolies are less likely than private companies to react to market signals and to benefit from commercial options being offered by gas flaring reduction projects because they are short of cash, suffer from political interference, and lack incentives to perform better.

In Alberta, Canada, flaring reduction targets were imposed, with the effect that the industry reevaluated all of the flaring that was taking place and were able to introduce improvement projects that allowed required emissions reductions targets to be exceeded well ahead of the required schedule for compliance. In many cases the work needed to do this was less than expected. Further, on close examination of various flaring situations, the companies found that many of the needed flaring reduction projects were commercially viable. Details can be found on the Alberta Energy and Utilities Board website.[39]

9.4 Recommendations

The following recommendations arose from these findings:

- Among the regulatory and institutional barriers that would need to be addressed, one of the most important is the opportunities for nonstate entities to take part in the production and distribution of gas and electricity.
- The project has highlighted the need to deal with the LPG distribution at a strategic level. Since LPG production will be an integral part of many flare gas usage projects in the developing country it will be necessary to investigate the framework for LPG distribution as part of a decision to produce LPG. Future LPG demand (local and regional) is a critical factor and the relation between government subsidy policy and LPG demand has to be scrutinized.
- Governments should be advised to focus on following key requirements for successful development of economic small-scale gas transport projects:
  - Availability of a wholesale-priced natural gas supply (that is, the gas should already be developed for the benefit of an anchor customer)
  - Access to gas transportation in major pipelines at the same prices as large users (if pipelines will be the gas source for small projects)

[39] http://www.eub.gov.ab.ca/bbs/default.htm

  - Inexpensive access to pipeline right of way for small-scale pipelines
  - Access to technology and expertise (appropriate technology for the local situation and the local skills—minimal use of expensive outside experts and services)
  - Availability of financing for new projects and for customer fuel conversion equipment
  - Tax or other incentives to motivate customers to convert to gas

- Capacity building regarding gas usage possibilities should be introduced in the countries targeted by the GGFR to facilitate partnerships between state-owned national oil companies and the private sector.

- For the surveyed projects in Chad and Ecuador, it is recommended that the next steps be taken toward their implementation. The first steps include followup studies be completed to determine how the projects might best be structured institutionally and commercially, preparation of a detailed gas utilization strategy, additional socioeconomic surveys to deal with pricing, subsidies and the opportunities to achieve poverty alleviation as well as detailed project design. However, none of these activities should delay the actual implementation of the projects as this will allow the respective authorities to gain experience and learn how to do them first hand. It is recommended that the authorities be supported with appropriate commercial, technical, and construction expertise for implementation as required. Implementing projects will help to develop the skills needed to identify and develop additional projects. Mozambique is a good example of this chain of events.

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Appendix A: Economic and Financial Calculations—Chad

Financial Analysis Case 1

Scenario 0	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year			4,303	5,947	6,755	8,048	9,490	10,144	11,490	11,149	12,166	13,357	13,261	11,473	10,919	9,735	7,062
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	m^3/year			32,960	35,288	36,733	38,707	40,854	42,168	44,237	44,510	46,251	48,191	48,766	47,541	47,653	47,103	44,973
HFO exported	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Refinery HFO for power production	m^3/year			15,821	16,938	17,632	18,580	19,610	20,241	21,234	21,365	22,200	23,132	23,408	22,820	22,874	22,610	21,587
Additional crude/HFO for power prod.	m^3/year			6,662	7,262	7,745	8,329	9,062	10,242	11,443	13,496	15,101	16,780	19,298	22,875	26,020	29,707	34,392
Gas flared	t/year			48,509	51,941	54,305	57,375	60,899	64,520	68,895	73,253	78,117	83,319	88,882	94,833	101,197	108,003	115,284
Ton CO_2 in flared gas	t			140,675	150,629	157,486	166,387	176,608	187,108	199,796	212,434	226,540	241,625	257,759	275,015	293,470	313,210	334,323
Total amount of gas flared	***t***	***1,149,333***	***100% of max.***															
Income from Sale of Products																		
Gasoline used in Chad	US$ million			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	US$ million			1.7	2.3	2.6	3.1	3.6	3.9	4.4	4.3	4.7	5.1	5.1	4.4	4.2	3.7	2.7
Diesel	US$ million			15.8	16.9	17.6	18.6	19.6	20.3	21.2	21.4	22.2	23.1	23.4	22.8	22.9	22.6	21.6
Refinery HFO for power production	US$ million			2.6	2.7	2.8	3.0	3.2	3.3	3.4	3.4	3.6	3.7	3.8	3.7	3.7	3.7	3.5
Total income	***US$ million***	***-***	***-***	***32.7***	***34.9***	***36.3***	***38.2***	***40.2***	***41.5***	***43.4***	***43.7***	***45.4***	***47.2***	***47.8***	***46.7***	***46.9***	***46.5***	***44.6***
	NPV 175.7																	
Cost																		
Extra investments	US$ million		78.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extra O&M	US$ million			3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Total costs	***US$ million***	***0.0***	***78.1***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***	***3.9***
	NPV 76.4																	
Net Income - Scenario 0	***US$ million***	***0.0***	***-78.1***	***28.8***	***31.0***	***32.4***	***34.3***	***36.3***	***37.5***	***39.5***	***39.8***	***41.5***	***43.3***	***43.9***	***42.8***	***43.0***	***42.5***	***40.7***
Net Income - Scenario 0	***99.3 NPV 20 years, US$ million***																	

Scenario 1	**Year**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Gasoline used in Chad	m^3/year	0	0	26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year	0	0	4,303	5,947	6,755	8,048	9,490	10,144	11,490	11,149	12,166	13,357	13,261	11,473	10,919	9,735	7,062
Jet fuel	m^3/year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	m^3/year	0	0	32,960	35,288	36,733	38,707	40,854	42,168	44,237	44,510	46,251	48,191	48,766	47,541	47,653	47,103	44,973
HFO exported	m^3/year	0	0	9,240	9,876	10,244	10,764	11,299	11,416	11,779	11,277	11,406	11,582	11,050	9,597	8,725	7,470	5,388
Refinery HFO for power production	m^3/year	0	0	6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12,358	13,223	14,149	15,139	16,199
Gas to power production	t/year	0	0	28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas flared	t/year	0	0	19,762	20,981	21,831	22,925	24,177	25,463	27,011	28,553	30,271	32,106	34,067	36,162	38,401	40,794	43,352
Ton CO_2 in flared gas	t	0	0	57,310	60,846	63,309	66,482	70,114	73,843	78,331	82,803	87,785	93,107	98,794	104,870	111,364	118,303	125,720
Ton CO_2 reduction	t	0	0	83,365	89,783	94,176	99,905	106,495	113,265	121,465	129,631	138,755	148,518	158,965	170,144	182,107	194,907	208,603
Total amount of gas flared	***t***	***445,856***	***39%***	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			1.7	2.3	2.6	3.1	3.6	3.9	4.4	4.3	4.7	5.1	5.1	4.4	4.2	3.7	2.7
Jet fuel	million US$			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel	million US$			15.8	16.9	17.6	18.6	19.6	20.3	21.2	21.4	22.2	23.1	23.4	22.8	22.9	22.6	21.6
HFO exported	million US$			0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.7	0.5
Refinery HFO for power production	million US$			1.2	1.3	1.4	1.5	1.5	1.6	1.8	1.9	2.0	2.1	2.3	2.5	2.6	2.8	3.0
Gas to power production	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Total income	million US$	0	0	37.6	40.1	41.8	44.0	46.4	48.1	50.6	51.4	53.7	56.2	57.5	57.3	58.3	58.8	57.9
NPV	206.0																	
Cost																		
Extra investments	million US$		114.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extra O&M	million US$			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Total costs	***million US$***	***0***	***114.1***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***	***5.7***
NPV	111.5462489																	
Net income - Scenario 1	*million US$*	*0*	*-114.1*	*31.9*	*34.4*	*36.1*	*38.3*	*40.7*	*42.4*	*44.8*	*45.7*	*48.0*	*50.4*	*51.8*	*51.5*	*52.6*	*53.1*	*52.2*
Net income - Scenario 1	***94.4 NPV 20 years, US$ million***																	
	0.5 NPV, million ton CO_2																	

Scenario 2	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year			4,303	5,947	6,755	8,048	9,490	10,144	11,490	11,149	12,166	13,357	13,261	11,473	10,919	9,735	7,062
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	m^3/year			32,960	35,288	36,733	38,707	40,854	42,168	44,237	44,510	46,251	48,191	48,766	47,541	47,653	47,103	44,973
HFO exported	m^3/year			9,240	9,876	10,244	10,764	11,299	11,416	11,779	11,277	11,406	11,582	11,050	9,597	8,725	7,470	5,388
Refinery HFO for power production	m^3/year			6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12,358	13,223	14,149	15,139	16,199
Gas to power production	t/year			28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas to industrial zone	t/year			2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3,385
Gas flared	t/year			16,817	18,007	18,826	19,891	21,112	22,368	23,884	25,395	27,081	28,885	30,814	32,876	35,083	37,442	39,966
Ton CO^2 in flared gas	t			48,769	52,220	54,597	57,683	61,226	64,866	69,265	73,646	78,536	83,766	89,359	95,341	101,739	108,583	115,902
Ton CO_2 reduction	t	0	0	91,906	98,409	102,889	108,705	115,382	122,242	130,532	138,788	148,004	157,859	168,400	179,673	191,731	204,627	218,421
Total amount of gas flared	***t***	***398,447***	***35%***	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			1.7	2.3	2.6	3.1	3.6	3.9	4.4	4.3	4.7	5.1	5.1	4.4	4.2	3.7	2.7
Jet fuel	million US$			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel	million US$			15.8	16.9	17.6	18.6	19.6	20.3	21.2	21.4	22.2	23.1	23.4	22.8	22.9	22.6	21.6
HFO exported	million US$			0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.7	0.5
Refinery HFO for power production	million US$			1.2	1.3	1.4	1.5	1.5	1.6	1.8	1.9	2.0	2.1	2.3	2.5	2.6	2.8	3.0
Gas to power production	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Gas to industries	million US$			0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total income	*million US$*	*0*	*0.0*	*38.1*	*40.7*	*42.3*	*44.5*	*47.0*	*48.7*	*51.1*	*52.0*	*54.3*	*56.7*	*58.1*	*57.9*	*58.9*	*59.4*	*58.6*
NPV	***208.5***																	
Cost																		
Extra investments	million US$		114.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extra O&M	million US$			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Total costs	*million US$*	*0*	*114.1*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*	*5.7*
NPV	111.5462489																	
Net income - Scenario 2	*million US$*	*0*	*-114.1*	*32.4*	*35.0*	*36.6*	*38.8*	*41.2*	*43.0*	*45.4*	*46.3*	*48.6*	*51.0*	*52.4*	*52.2*	*53.2*	*53.7*	*52.9*
Net income - Scenario 2	**96.9 NPV 20 years, million US$**																	
	0.5 NPV, million ton CO_2																	

Scenario 3	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year			4,303	5,947	6,755	8,048	9,490	10,144	11,490	11,149	12,166	13,357	13,261	11,473	10,919	9,735	7,062
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel	m^3/year			32,960	35,288	36,733	38,707	40,854	42,168	44,237	44,510	46,251	48,191	48,766	47,541	47,653	47,103	44,973
HFO exported	m^3/year			9,240	9,876	10,244	10,764	11,299	11,416	11,779	11,277	11,406	11,582	11,050	9,597	8,725	7,470	5,388
Refinery HFO for power production	m3/year			6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12,358	13,223	14,149	15,139	16,199
Gas to power production	t/year			28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas to industrial zone	t/year			2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3,385
LPG to local market	t/year			545	599	659	725	797	877	965	1,061	1,167	1,284	1,412	1,554	1,709	1,880	2,068
LPG to export market	t/year			16,272	17,408	18,168	19,166	20,315	21,491	22,920	24,334	25,914	27,601	29,401	31,323	33,374	35,563	37,898
Gas flared	t/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ton CO_2 in flared gas	t			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total amount of gas flared	t	0	0%	of max.														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			1.7	2.3	2.6	3.1	3.6	3.9	4.4	4.3	4.7	5.1	5.1	4.4	4.2	3.7	2.7
Jet fuel	million US$			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel	million US$			15.8	16.9	17.6	18.6	19.6	20.3	21.2	21.4	22.2	23.1	23.4	22.8	22.9	22.6	21.6
HFO exported	million US$			0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.7	0.5
Refinery HFO for power production	million US$			1.2	1.3	1.4	1.5	1.5	1.6	1.8	1.9	2.0	2.1	2.3	2.5	2.6	2.8	3.0
Gas to power production	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Gas to industries	million US$			0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
LPG sold to local market	million US$			0.7	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.6	1.7	1.9	2.1	2.3	2.5
LPG sold to export market	million US$			1.4	1.5	1.5	1.6	1.7	1.8	1.9	2.0	2.2	2.3	2.5	2.6	2.8	3.0	3.2
Total income	million US$	0	0	40.1	42.9	44.6	47.0	49.6	51.5	54.2	55.3	57.9	60.6	62.3	62.4	63.8	64.7	64.3
NPV	***221.4***																	
Cost																		
Extra investments	million US$		114.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extra O&M	million US$			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Total costs	million US$	0.0	114.1	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
NPV	***111.5***																	
Net Income - Scenario 3	***million US$***	***0.0***	***-114.1***	***34.4***	***37.2***	***38.9***	***41.3***	***43.9***	***45.8***	***48.5***	***49.6***	***52.2***	***54.9***	***56.5***	***56.7***	***58.1***	***59.0***	***58.6***
Net Income - Scenario 3	***109.9 NPV, million US$***																	
	1.1 NPV, million ton CO_2																	

Financial Analysis Case 2

Scenario 0	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year	0	0	26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year	0	0	6,167	7,550	8,943	10,163	11,192	12,249	13,477	14,793	16,298	17,892	19,494	21,043	22,700	24,544	26,275
Diesel used in Chad	m^3/year	0	0	34,957	37,006	39,076	40,974	42,678	44,424	46,365	48,414	50,678	53,051	55,444	57,795	60,275	62,971	65,558
HFO exported	m^3/year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Refinery HFO for power production	m^3/year	0	0	16,780	17,763	18,757	19,668	20,485	21,324	22,255	23,239	24,326	25,464	26,613	27,742	28,932	30,226	31,468
Additional crude/HFO for power prod.	m^3/year	0	0	5,704	6,437	6,620	7,242	8,187	9,160	10,421	11,622	12,975	14,448	16,093	17,954	19,962	22,091	24,511
Gas flared	t/year	0	0	51,448	54,470	57,770	60,735	63,618	67,972	72,210	79,679	85,596	91,721	101,054	115,286	128,000	144,385	168,054
Ton CO2 in flared gas	t	0	0	149,199	157,963	167,534	176,130	184,492	197,118	209,409	231,068	248,228	265,992	293,058	334,328	371,200	418,717	487,355
Total amount of gas flared	***t***	***1,341,997***	***100%***	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			2.4	2.9	3.4	3.9	4.3	4.7	5.2	5.7	6.3	6.9	7.5	8.1	8.7	9.4	10.1
Diesel used in Chad	million US$			16.8	17.8	18.8	19.7	20.5	21.3	22.3	23.3	24.3	25.5	26.6	27.8	29.0	30.2	31.5
HFO to power porduction	million US$			2.7	2.9	3.0	3.2	3.3	3.4	3.6	3.8	3.9	4.1	4.3	4.5	4.7	4.9	5.1
Total income	***million US$***	***-***	***-***	***34.6***	***36.5***	***38.5***	***40.2***	***41.9***	***43.5***	***45.4***	***47.3***	***49.4***	***51.7***	***53.9***	***56.1***	***58.5***	***61.0***	***63.4***
NPV	***191.2***																	
Cost																		
Extra investments	million US$		98.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extra O&M	million US$	-	-	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Total costs	***million US$***	***-***	***98.0***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***	***4.9***
NPV	***95.8***																	
Net income of Scenario 0	***million US$***	***-***	***(98.0)***	***29.7***	***31.6***	***33.6***	***35.3***	***37.0***	***38.6***	***40.5***	***42.4***	***44.5***	***46.8***	***49.0***	***51.2***	***53.6***	***56.1***	***58.5***
Net income of Scenario 0	***95.5 NPV 20 years, million US$***																	

Scenario 1	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year	0	0	26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32254	32,899	33,557	34,228	34,913
Gasoline exported	m^3/year	0	0	6,167	7,550	8,943	10,163	11,192	12,249	13,477	14,793	16,298	17,892	19494	21,043	22,700	24,544	26,275
Diesel used in Chad	m^3/year	0	0	34,957	37,006	39,076	40,974	42,678	44,424	46,365	48,414	50,678	53,051	55444	57,795	60,275	62,971	65,558
HFO exported	m^3/year	0	0	10,198	10,701	11,369	11,852	12,174	12,499	12,800	13,151	13,531	13,915	14255	14,518	14,783	15,087	15,269
Refinery HFO for power production	m^3/year	0	0	6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12358	13,223	14,149	15,139	16,199
Gas to power production	t/year	0	0	28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54816	58,671	62,795	67,209	71,932
Gas flared	t/year	0	0	22,701	23,510	25,296	26,285	26,896	28,915	30,325	34,978	37,749	40,508	46239	56,615	65,205	77,176	96,121
Ton CO_2 in flared gas	t	0	0	65,833	68,180	73,357	76,225	77,997	83,853	87,943	101,437	109,473	117,474	134092	164,184	189,093	223,810	278,752
Ton CO_2 reduction	t	0	0	83,365	89,783	94,176	99,905	106,495	113,265	121,465	129,631	138,755	148,518	158965	170,144	182,107	194,907	208,603
Total amount of gas flared	**t**	**638,519**	**48%**	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			2.4	2.9	3.4	3.9	4.3	4.7	5.2	5.7	6.3	6.9	7.5	8.1	8.7	9.4	10.1
Diesel used in Chad	million US$			16.8	17.8	18.8	19.7	20.5	21.3	22.3	23.3	24.3	25.5	26.6	27.8	29.0	30.2	31.5
HFO exported	million US$			0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2
Refinery HFO for power production	million US$			1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.1	2.3	2.4	2.6
Gas to power production	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Total income	***million US$***	***-***	***-***	***39.1***	***41.4***	***43.5***	***45.6***	***47.7***	***49.7***	***52.0***	***54.5***	***57.2***	***60.0***	***62.9***	***65.8***	***68.9***	***72.2***	***75.5***
NPV	***219.3***																	
Cost																		
Extra investments	million US$		134.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Total costs	***million US$***	***-***	***134.0***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***
NPV	***130.9***																	
Net income of Scenario 1	***million US$***	***-***	***(134.0)***	***32.4***	***34.7***	***36.8***	***38.9***	***41.0***	***43.0***	***45.3***	***47.8***	***50.5***	***53.3***	***56.2***	***59.1***	***62.2***	***65.5***	***68.8***
Net income of Scenario 1	***88.4 NPV 20 years, million US$***																	
	0.5 NPV, million ton CO_2																	

Scenario 2	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year	0	0	26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34913
Gasoline exported	m^3/year	0	0	6,167	7,550	8,943	10,163	11,192	12,249	13,477	14,793	16,298	17,892	19,494	21,043	22,700	24,544	26275
Diesel used in Chad	m^3/year	0	0	34,957	37,006	39,076	40,974	42,678	44,424	46,365	48,414	50,678	53,051	55,444	57,795	60,275	62,971	65558
HFO exported	m^3/year	0	0	10,198	10,701	11,369	11,852	12,174	12,499	12,800	13,151	13,531	13,915	14,255	14,518	14,783	15,087	15269
Refinery HFO for power production	m^3/year	0	0	6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12,358	13,223	14,149	15,139	16199
Gas to power production	t/year	0	0	28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71932
Gas to industrial zone	t/year	0	0	2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3385
Gas flared	t/year	0	0	19,756	20,536	22,291	23,250	23,831	25,819	27,199	31,821	34,560	37,287	42,985	53,329	61,886	73,824	92736
Ton CO_2 in flared gas	t	0	0	57,292	59,554	64,645	67,426	69,110	74,876	78,877	92,280	100,224	108,133	124,658	154,655	179,469	214,090	268935
Ton CO_2 reduction	t	0	0	91,906	98,409	102,889	108,705	115,382	122,242	130,532	138,788	148,004	157,859	168,400	179,673	191,731	204,627	218421
Total amount of gas flared	**t**	**591,111**	**44%**	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			2.4	2.9	3.4	3.9	4.3	4.7	5.2	5.7	6.3	6.9	7.5	8.1	8.7	9.4	10.1
Diesel used in Chad	million US$			16.8	17.8	18.8	19.7	20.5	21.3	22.3	23.3	24.3	25.5	26.6	27.8	29.0	30.2	31.5
HFO exported	million US$			0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2
Refinery HFO for power production	million US$			1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.1	2.3	2.4	2.6
Gas to power production	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Gas to industries	million US$			0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total income	***million US$***	***-***	***-***	***39.6***	***41.9***	***44.1***	***46.2***	***48.2***	***50.3***	***52.6***	***55.1***	***57.8***	***60.6***	***63.5***	***66.4***	***69.5***	***72.8***	***76.1***
NPV	***221.9***																	
Cost																		
Extra investments	million US$		134.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Total costs	***million US$***	***-***	***134.0***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***
NPV	***130.9***																	
Net income of Scenario 2	***million US$***	***-***	***(134.0)***	***32.9***	***35.2***	***37.4***	***39.5***	***41.5***	***43.6***	***45.9***	***48.4***	***51.1***	***53.9***	***56.8***	***59.7***	***62.8***	***66.1***	***69.4***
Net income of Scenario 2	***90.9 NPV 20 years, million US$***																	
	0.5 NPV, million ton CO_2																	

Scenario 3	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m_3/year	0	0	26,459	26,989	27,528	28,079	28,641	29,213	29,798	30,394	31,001	31,621	32,254	32,899	33,557	34,228	34,913
Gasoline exported	m_3/year	0	0	6,167	7,550	8,943	10,163	11,192	12,249	13,477	14,793	16,298	17,892	19,494	21,043	22,700	24,544	26,275
Diesel used in Chad	m_3/year	0	0	34,957	37,006	39,076	40,974	42,678	44,424	46,365	48,414	50,678	53,051	55,444	57,795	60,275	62,971	65,558
HFO exported	m_3/year	0	0	10,198	10,701	11,369	11,852	12,174	12,499	12,800	13,151	13,531	13,915	14,255	14,518	14,783	15,087	15,269
Refinery HFO for power production	m_3/year	0	0	6,581	7,062	7,388	7,816	8,311	8,825	9,455	10,088	10,794	11,550	12,358	13,223	14,149	15,139	16,199
Gas to power production	t/year	0	0	28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas to industrial zone	t/year	0	0	2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3,385
LPG to local market	t/year	0	0	545	599	659	725	797	877	965	1,061	1,167	1,284	1,412	1,554	1,709	1,880	2,068
LPG to export	t/year	0	0	17,291	18,285	19,369	20,331	21,258	22,687	24,069	26,562	28,507	30,514	33,621	38,413	42,666	48,175	56,193
Gas flared	t/year	0	0	1,920	1,652	2,264	2,195	1,776	2,255	2,165	4,198	4,886	5,489	7,952	13,362	17,511	23,769	34,476
Ton CO_2 in flared gas	t	0	0	5,569	4,792	6,564	6,365	5,150	6,540	6,280	12,174	14,169	15,919	23,061	38,751	50,783	68,930	99,980
Total amount of gas flared	**t**	**125,872**	**9%**	***of max.***														
Income from Sale of Products																		
Gasoline used in Chad	million US$			12.7	13.0	13.2	13.5	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8	16.1	16.4	16.8
Gasoline exported	million US$			2.4	2.9	3.4	3.9	4.3	4.7	5.2	5.7	6.3	6.9	7.5	8.1	8.7	9.4	10.1
Diesel used in Chad	million US$			16.8	17.8	18.8	19.7	20.5	21.3	22.3	23.3	24.3	25.5	26.6	27.8	29.0	30.2	31.5
HFO exported	million US$			0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2
Refinery HFO for power production	million US$			1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.1	2.3	2.4	2.6
Gas to power porduction	million US$			5.3	5.8	6.0	6.4	6.8	7.3	7.8	8.3	8.9	9.5	10.2	10.9	11.7	12.5	13.4
Gas to industries	million US$			0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
LPG sold to local market	million US$			0.7	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.6	1.7	1.9	2.1	2.3	2.5
LPG sold to export market	million US$			1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.2	2.4	2.5	2.8	3.2	3.6	4.0	4.7
Total income	***million US$***	***-***	***-***	***41.7***	***44.2***	***46.5***	***48.8***	***51.0***	***53.3***	***55.8***	***58.6***	***61.6***	***64.7***	***68.0***	***71.5***	***75.1***	***79.1***	***83.4***
NPV	***235.7***																	
Cost																		
Extra investments	million US$		134.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Total costs	***million US$***	***0.0***	***134.0***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***	***6.7***
NPV	***130.9***																	
Net income of Scenario 3	***million US$***	***-***	***(134.0)***	***35.0***	***37.5***	***39.8***	***42.1***	***44.3***	***46.6***	***49.1***	***51.9***	***54.9***	***58.0***	***61.3***	***64.8***	***68.4***	***72.4***	***76.7***
Net income of Scenario 3	***104.8 NPV, million US$***																	
Reduction of CO_{+2} emission	***1.2 NPV, million ton CO2***																	

Economic Analysis—Case 2

Scenario 0	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			24,794	24,581	24,368	24,156	23,943	23,730	23,517	23,305	23,092	22,879	22,667	22,454	22,241	22,028	21,816
Gasoline exported	m^3/year			5,139	7,106	9,091	10,929	12,601	14,309	16,184	18,151	20,302	22,546	24,809	27,034	29,371	31,891	34,320
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel used in Chad	m^3/year			32,071	33,950	35,850	37,591	39,154	40,756	42,537	44,417	46,494	48,670	50,866	53,023	55,298	57,771	60,145
HFO sold	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO to power production	m^3/year			15,394	16,296	17,208	18,044	18,794	19,563	20,418	21,320	22,317	23,362	24,416	25,451	26,543	27,730	28,870
HFO or Crude purchased by STEE	m^3/year			7,089	7,904	8,168	8,865	9,878	10,920	12,259	13,541	14,984	16,550	18,290	20,244	22,351	24,586	27,109
Gas flared	t/year			51,448	54,470	57,770	60,735	63,618	67,972	72,210	79,679	85,596	91,721	101,054	115,286	128,000	144,385	168,054
Ton CO2 in flared gas	t			149,199	157,963	167,534	176,130	184,492	197,118	209,409	231,068	248,228	265,992	293,058	334,328	371,200	418,717	487,355
Total amount of gas flared	***t***	***1,341,997***	***100% of max.***															
Saved economic cost																		
Gasoline used in Chad	million US$			11.9	11.8	11.7	11.6	11.5	11.4	11.3	11.2	11.1	11.0	10.9	10.8	10.7	10.6	10.5
Gasoline exported	million US$			2.0	2.7	3.5	4.2	4.8	5.5	6.2	7.0	7.8	8.7	9.5	10.4	11.3	12.3	13.2
Jet fuel	million US$			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel used in Chad	million US$			15.4	16.3	17.2	18.1	18.8	19.6	20.4	21.3	22.3	23.4	24.4	25.5	26.6	27.7	28.9
Total saved costs	***million US$***	***-***	***-***	***29.3***	***30.8***	***32.4***	***33.9***	***35.1***	***36.5***	***37.9***	***39.5***	***41.2***	***43.0***	***44.9***	***46.6***	***48.5***	***50.6***	***52.6***
NPV	***235.1***																	
Cost																		
HFO to power production	million US$			1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.2
HFO or Crude purchased by STEE	million US$			0.5	0.6	0.6	0.7	0.8	0.8	0.9	1.0	1.1	1.3	1.4	1.5	1.7	1.9	2.1
Extra investments	million US$		131.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extra O&M	million US$			6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Cost of CO2 from gas flaring	million US$			3.0	3.2	3.4	3.5	3.7	3.9	4.2	4.6	5.0	5.3	5.9	6.7	7.4	8.4	9.7
Total costs	***million US$***	***-***	***131.0***	***11.2***	***11.5***	***11.8***	***12.1***	***12.4***	***12.8***	***13.2***	***13.8***	***14.3***	***14.9***	***15.7***	***16.7***	***17.7***	***18.9***	***20.6***
NPV	***193.2***																	
Total benefits of Scenario 0	***million US$***	***-***	***-131.0***	***18.0***	***19.3***	***20.6***	***21.7***	***22.7***	***23.7***	***24.7***	***25.7***	***26.9***	***28.1***	***29.2***	***29.9***	***30.8***	***31.7***	***32.0***
Total benefits of Scenario 0	***41.9***	***NPV 20 years, million US$***																

Scenario 1	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			24,794	24,581	24,368	24,156	23,943	23,730	23,517	23,305	23,092	22,879	22,667	22,454	22,241	22,028	21,816
Gasoline exported	m^3/year			5,139	7,106	9,091	10,929	12,601	14,309	16,184	18,151	20,302	22,546	24,809	27,034	29,371	31,891	34,320
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel used in Chad	m^3/year			32,071	33,950	35,850	37,591	39,154	40,756	42,537	44,417	46,494	48,670	50,866	53,023	55,298	57,771	60,145
HFO sold	m^3/year			15,394	16,296	17,208	18,044	18,794	19,563	20,418	21,320	22,317	23,362	24,416	25,451	26,543	27,730	28,870
HFO to power production	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to power production	t/year			28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas flared	t/year			22,701	23,510	25,296	26,285	26,896	28,915	30,325	34,978	37,749	40,508	46,239	56,615	65,205	77,176	96,121
Ton CO_2 in flared gas	t			65,833	68,180	73,357	76,225	77,997	83,853	87,943	101,437	109,473	117,474	134,092	164,184	189,093	223,810	278,752
Total amount of gas flared	**t**	**638,519**	**48% *of max.***															
Saved economic cost																		
Gasoline used in Chad	million US$			11.9	11.8	11.7	11.6	11.5	11.4	11.3	11.2	11.1	11.0	10.9	10.8	10.7	10.6	10.5
Gasoline exported	million US$			2.0	2.7	3.5	4.2	4.8	5.5	6.2	7.0	7.8	8.7	9.5	10.4	11.3	12.3	13.2
Jet fuel	million US$			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel used in Chad	million US$			15.4	16.3	17.2	18.1	18.8	19.6	20.4	21.3	22.3	23.4	24.4	25.5	26.6	27.7	28.9
HFO sold	million US$			1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.2
CO_2 benefit of gas to power	million US$			0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.1
Total saved costs	***million US$***	**-**	**-**	***30.9***	***32.6***	***34.2***	***35.8***	***37.1***	***38.6***	***40.2***	***41.8***	***43.7***	***45.6***	***47.6***	***49.5***	***51.5***	***53.7***	***55.9***
NPV	***248.8***																	
Cost																		
Gas to power production	million US$																	
Extra investments	million US$		167.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Cost of CO_2 from gas flaring	million US$			1.3	1.4	1.5	1.5	1.6	1.7	1.8	2.0	2.2	2.3	2.7	3.3	3.8	4.5	5.6
Total costs	***million US$***	**-**	***167.0***	***9.7***	***9.7***	***9.8***	***9.9***	***9.9***	***10.0***	***10.1***	***10.4***	***10.5***	***10.7***	***11.0***	***11.6***	***12.1***	***12.8***	***13.9***
NPV	***203.5***																	
Total benefits of Scenario 1	***million US$***	**-**	***-167.0***	***21.2***	***22.8***	***24.4***	***25.9***	***27.2***	***28.5***	***30.0***	***31.4***	***33.1***	***34.9***	***36.5***	***37.9***	***39.4***	***40.9***	***41.9***
Total benefits of Scenario 1	***45.3 NPV 20 years, million US$***																	

Scenario 2	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Gasoline used in Chad	m^3/year			24,794	24,581	24,368	24,156	23,943	23,730	23,517	23,305	23,092	22,879	22,667	22,454	22,241	22,028	21,816
Gasoline exported	m^3/year			5,139	7,106	9,091	10,929	12,601	14,309	16,184	18,151	20,302	22,546	24,809	27,034	29,371	31,891	34,320
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel used in Chad	m^3/year			32,071	33,950	35,850	37,591	39,154	40,756	42,537	44,417	46,494	48,670	50,866	53,023	55,298	57,771	60,145
HFO sold	m^3/year			15,394	16,296	17,208	18,044	18,794	19,563	20,418	21,320	22,317	23,362	24,416	25,451	26,543	27,730	28,870
HFO to power production	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to power production	t/year			28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas to industrial zone	t/year			2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3,385
Gas flared	t/year			19,756	20,536	22,291	23,250	23,831	25,819	27,199	31,821	34,560	37,287	42,985	53,329	61,886	73,824	92,736
Ton CO_2 in flared gas	t			57,292	59,554	64,645	67,426	69,110	74,876	78,877	92,280	100,224	108,133	124,658	154,655	179,469	214,090	268,935
Total amount of gas flared	**t**	**591,111**	***44% of max.***															
Saved economic cost																		
Gasoline used in Chad	million US$			11.9	11.8	11.7	11.6	11.5	11.4	11.3	11.2	11.1	11.0	10.9	10.8	10.7	10.6	10.5
Gasoline exported	million US$			2.0	2.7	3.5	4.2	4.8	5.5	6.2	7.0	7.8	8.7	9.5	10.4	11.3	12.3	13.2
Jet fuel	million US$			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel used in Chad	million US$			15.4	16.3	17.2	18.1	18.8	19.6	20.4	21.3	22.3	23.4	24.4	25.5	26.6	27.7	28.9
HFO sold	million US$			1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.2
Value of gas to industries	million US$			0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CO2 benefit of gas to power & indus.	million US$			0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.1	1.2
Total saved costs	***million US$***	***-***	***-***	***31.2***	***32.9***	***34.5***	***36.1***	***37.5***	***38.9***	***40.5***	***42.1***	***44.0***	***45.9***	***47.9***	***49.8***	***51.9***	***54.1***	***56.2***
	NPV 250.8																	
Cost																		
Gas to power production	million US$									-								
Extra investments	million US$		167.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Cost of CO_2 from gas flaring	million US$			1.1	1.2	1.3	1.3	1.4	1.5	1.6	1.8	2.0	2.2	2.5	3.1	3.6	4.3	5.4
Total costs	***million US$***	***-***	***167.4***	***9.5***	***9.6***	***9.7***	***9.7***	***9.8***	***9.9***	***9.9***	***10.2***	***10.4***	***10.5***	***10.9***	***11.5***	***12.0***	***12.6***	***13.7***
	NPV 202.7																	
Total benefits of Scenario 2	***million US$***	***-***	***167.4***	***21.7***	***23.3***	***24.9***	***26.4***	***27.7***	***29.0***	***30.5***	***31.9***	***33.6***	***35.4***	***37.0***	***38.4***	***39.9***	***41.4***	***42.5***
Total benefits of Scenario 2	***48.1 NPV 20 years, million US$***																	

Scenario 3	**Year**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Gasoline used in Chad	m^3/year			24,794	24,581	24,368	24,156	23,943	23,730	23,517	23,305	23,092	22,879	22,667	22,454	22,241	22,028	21,816
Gasoline exported	m^3/year			5,139	7,106	9,091	10,929	12,601	14,309	16,184	18,151	20,302	22,546	24,809	27,034	29,371	31,891	34,320
Jet fuel	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel used in Chad	m^3/year			32,071	33,950	35,850	37,591	39,154	40,756	42,537	44,417	46,494	48,670	50,866	53,023	55,298	57,771	60,145
HFO sold	m^3/year			15,394	16,296	17,208	18,044	18,794	19,563	20,418	21,320	22,317	23,362	24,416	25,451	26,543	27,730	28,870
HFO to power production	m^3/year			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas to power production	t/year			28,747	30,960	32,475	34,450	36,722	39,057	41,885	44,700	47,847	51,213	54,816	58,671	62,795	67,209	71,932
Gas to industrial zone	t/year			2,945	2,975	3,004	3,034	3,065	3,095	3,126	3,158	3,189	3,221	3,253	3,286	3,319	3,352	3,385
LPG to local market	t/year			545	599	659	725	797	877	965	1,061	1,167	1,284	1,412	1,554	1,709	1,880	2,068
LPG to export	t/year			17,291	18,285	19,369	20,331	21,258	22,687	24,069	26,562	28,507	30,514	33,621	38,413	42,666	48,175	56,193
Gas flared	t/year			1,920	1,652	2,264	2,195	1,776	2,255	2,165	4,198	4,886	5,489	7,952	13,362	17,511	23,769	34,476
Ton CO2 in flared gas	t			5,569	4,792	6,564	6,365	5,150	6,540	6,280	12,174	14,169	15,919	23,061	38,751	50,783	68,930	99,980
Total amount of gas flared	**t**	**125,872**	**9%** ***of max.***															
Saved economic cost																		
Gasoline used in Chad	million US$			11.9	11.8	11.7	11.6	11.5	11.4	11.3	11.2	11.1	11.0	10.9	10.8	10.7	10.6	10.5
Gasoline exported	million US$			2.0	2.7	3.5	4.2	4.8	5.5	6.2	7.0	7.8	8.7	9.5	10.4	11.3	12.3	13.2
Jet fuel	million US$			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel used in Chad	million US$			15.4	16.3	17.2	18.1	18.8	19.6	20.4	21.3	22.3	23.4	24.4	25.5	26.6	27.7	28.9
HFO sold	million US$			1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.2
Value of gas to industries	million US$			0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
LPG solde to local market	million US$			0.7	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.6	1.7	1.9	2.1	2.3	2.5
LPG solde to export market	million US$			1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.2	2.4	2.5	2.8	3.2	3.6	4.0	4.7
CO2 benefit of gas to power & indus.	million US$			0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.1	1.2
Total saved costs	***million US$***	***-***	***-***	***33.3***	***35.1***	***37.0***	***38.7***	***40.2***	***41.8***	***43.7***	***45.7***	***47.8***	***50.0***	***52.4***	***54.9***	***57.5***	***60.4***	***63.4***
NPV	***271.9***																	
Cost																		
Gas to power production	million US$			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extra investments	million US$		173.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra O&M	million US$			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Cost of CO_2 from gas flaring	million US$			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.5	0.8	1.0	1.4	2.0
Total costs	***million US$***	***0.0***	***173.1***	***8.8***	***8.8***	***8.8***	***8.8***	***8.8***	***8.8***	***8.8***	***8.9***	***8.9***	***9.0***	***9.1***	***9.4***	***9.7***	***10.0***	***10.7***
NPV	***199.5***																	
Total benefits of Scenario 3	***million US$***	***-***	***-173.1***	***24.5***	***26.4***	***28.2***	***29.9***	***31.5***	***33.1***	***34.9***	***36.8***	***38.9***	***41.1***	***43.3***	***45.5***	***47.8***	***50.4***	***52.8***
Total benefits of Scenario 3	***72.3 NPV 20 years, million US$***																	

Results of Economic Analyses

US$20 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	166.4	47.1	-	100	0
Scenario 1	226.3	176.7	49.6	2.5	39	61
Scenario 2	228.3	176.0	52.3	5.2	35	65
Scenario 3	247.8	173.9	73.9	26.8	0	100

CASE 2

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	235.1	193.2	41.9	-	100	0
Scenario 1	248.8	203.5	45.3	3.4	48	52
Scenario 2	250.8	202.7	48.1	6.2	44	56
Scenario 3	271.9	199.5	72.3	30.4	9	91

US$7 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	150.1	63.4	-	100	0
Scenario 1	223.6	170.3	53.3	(10.1)	39	61
Scenario 2	225.4	170.3	55.1	(8.3)	35	65
Scenario 3	244.9	173.9	71.0	7.7	0	100

CASE 2

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	235.1	174.9	60.3	-	100	0
Scenario 1	246.2	195.1	51.1	(9.2)	48	52
Scenario 2	248.0	195.0	52.9	(7.3)	44	56
Scenario 3	269.0	198.2	70.8	10.5	9	91

Plus 5% on Discounting Rate US$20 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	147.3	135.0	12.3	-	100	0
Scenario 1	156.0	149.6	6.4	(5.9)	39	61
Scenario 2	157.4	149.1	8.3	(4.0)	35	65
Scenario 3	170.4	148.9	21.4	9.1	0	100

CASE 2

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	160.4	157.1	3.3	-	100	0
Scenario 1	169.6	171.7	-2.0	(5.3)	48	52
Scenario 2	171.0	171.2	-0.2	(3.4)	44	56
Scenario 3	184.9	170.4	14.5	11.2	9	91

Plus 5% on Discounting Rate US$7 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	147.3	124.1	23.2	-	100	0
Scenario 1	154.2	145.3	8.9	(14.3)	39	61
Scenario 2	155.5	145.3	10.2	(13.1)	35	65
Scenario 3	168.4	148.9	19.5	-3.7	0	100

CASE 2

Scenario 0	213.5	150.1	63.4	-	100	0
Scenario 1	223.6	170.3	53.3	(10.1)	39	61
Scenario 2	225.4	175.4	50.0	(13.4)	35	65
Scenario 3	244.9	179.0	65.9	2.5	0	100

Plus 20% on Investment Cost US$20 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	191.6	21.9	-	100	0
Scenario 1	226.3	210.1	16.2	(5.8)	39	61
Scenario 2	228.3	209.4	18.9	(3.1)	35	65
Scenario 3	247.8	208.6	39.1	17.2	0	100

CASE 2

Scenario 0	235.1	223.1	12.1	-	100	0
Scenario 1	248.8	241.6	7.2	(4.8)	48	52
Scenario 2	250.8	240.9	9.9	(2.1)	44	56
Scenario 3	271.9	239.0	32.8	20.8	9	91

Plus 20% on Investment Cost US$7 per ton CO_2

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	175.3	38.2	-	100	0
Scenario 1	223.6	203.7	19.9	(18.3)	39	61
Scenario 2	225.4	203.8	21.7	(16.6)	35	65
Scenario 3	244.9	208.6	36.3	-1.9	0	100

CASE 2

Scenario 0	235.1	204.8	30.4	-	100	0
Scenario 1	246.2	233.2	13.0	(17.4)	48	52
Scenario 2	248.0	233.2	14.7	(15.6)	44	56
Scenario 3	269.0	237.7	31.3	0.9	9	91

Minus 20% on LPG Price in Cameroon (US$20 per ton CO_2)

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	166.4	47.1	-	100	0
Scenario 1	226.3	176.7	49.6	2.5	39	61
Scenario 2	228.3	176.0	52.3	5.2	35	65
Scenario 3	238.4	173.9	64.6	17.5	0	100

CASE 2

Scenario 0	235.1	193.2	41.9	-	100	0
Scenario 1	248.8	203.5	45.3	3.4	48	52
Scenario 2	250.8	202.7	48.1	6.2	44	56
Scenario 3	261.3	199.5	61.8	19.8	9	91

Minus 20% on LPG Price in Cameroon (US$7 per ton CO_2)

CASE 1

NPV million US$	Benefits	Costs	Net Benefits	Marginal benfits of reduced flaring	Gas Flared %	Gas Used %
Scenario 0	213.5	150.1	63.4	-	100	0
Scenario 1	223.6	170.3	53.3	(10.1)	39	61
Scenario 2	225.4	170.3	55.1	(8.3)	35	65
Scenario 3	235.5	173.9	61.7	-1.7	0	100

CASE 2

Scenario 0	235.1	174.9	60.3	-	100	0
Scenario 1	246.2	195.1	51.1	(9.2)	48	52
Scenario 2	248.0	195.0	52.9	(7.3)	44	56
Scenario 3	258.4	198.2	60.2	0.0	9	91

Appendix B: Economic and Financial Calculations Ecuador

General Assumptions

Economic discounting rate	***12%***		
Financial discounting rate	***15%***		
One U.S. gallon	3.785	litre	
Cost of diesel in Yuca (netback price)	***0.813***	US$ per gallon =	0.21 US$/liter
Cost of diesel in Yulebra (netback price)	***0.807***	US$ per gallon =	0.21 US$/liter
Cost of diesel in Coca (netback price)	***0.778***	US$ per gallon =	0.21 US$/liter
Cost of HFO at Thermal Power Plant in Ecuador	***16.00***	US$ per barrel	
	101.28	US$ per 1000 liter	
Financial Price of diesel in Yuca	***0.813***	US$ per gallon =	0.21 US$/liter
Financial Price of diesel in Yulebra	***0.807***	US$ per gallon =	0.21 US$/liter
Financial Price of diesel in Coca	***0.778***	US$ per gallon =	0.21 US$/liter
CO_2 emission from diesel	***20%***	more than from gas in terms of energy	
CO_2 emission from HFO	***30%***	more than from gas in terms of energy	
CO_2 emission from Yuca gas	***2.9***	kg CO_2 per m3	
CO_2 emission from Yulebra gas	***2.7***	kg CO_2 per m3	
Cost of CO_2 emission	***20***	US$ per ton CO_2	
Efficiency of diesel generators	***30%***		
Energy content of diesel	***42***	MJ per kg	
Electricity produced from diesel	3.5	kWh per kg	
Density	***0.84***	kg per litre	
Electricity per liter of diesel	2.94	kWh per liter	
Electricity per liter of gallon	11.1279	kWh per gallon	
Amount of diesel per kWh	0.0899	Gallon per kWh	
Amount of HFO per kWh delivered in Coca	0.4	liter per kWh	
Cost of diesel produced power at Yuca	73.04	US$ per MWh	
Cost of diesel produced power at Yulebra	72.53	US$ per MWh	
Cost of diesel produced power at Coca	69.87	US$ per MWh	
Cost of HFO produced power at Coca	37.89	US$ per MWh	
Price of diesel produced power at Yuca	73.04	US$ per MWh	
Price of diesel produced power at Yulebra	72.53	US$ per MWh	
Sales price of electricity in Coca	69.87	US$ per MWh	

Estimated cost structure of LPG	%	US$ / ton
Import price cif Ecuador	***100***	***315***
Bottling and storage	***0***	0.0
Local transportation	***0***	0.0
Netback price of LPG in Coca area		315.0
Sales price of LPG in Coca area		***315.0***

Technical Assumptions

Associated Gas—total:	**Yulebra**	**Yuca**
Flow m^3/day	***13,600***	***26,300***
Heat value (BTU/scf))	***1,119***	***1,146***
Heat value (kwh/m^3)	11.5	11.8
Total energy content MW	6.5	12.9
Mole % of C3 + C4	***5.5***	***10.9***
approx. heat value of C3 + C4 (kWh/m^3)	***29***	***29***
Annual power production (35% eff.) MWh	18,287	36,218
Associated Gas excl. C3 + C4:		
Flow m^3/day	12,852	23,433
Total energy content MW	5.6	9.5
Annual power production (35% eff.) MWh	15,757	26,519
Densitiy of LPG (kg per m^3)	***2.2***	***2.2***
Present own consumption of energy:		
Diesel gallons/day	***817***	***1867***
Annual diesel consumption m^3/year	1,035	2,365
Equivalent power consump (30% eff.) MW	0.38	0.87
Annual power consump (30% eff) MWh	3,043	6,953
Various calculated values:		
Quantity of C3 + C4 (kg/day)*	1,636	6,271
Power for compres. total flow to 20 bar (MW)—70% eff.	0.45	0.87
Annual power consump for compres. total flow to 20 bar—70% eff. (MWh)	3,598	6,958
Power for compres. total flow to 15 bar ** (MW)—70% eff.	0.34	0.65
Annual power consump for compres. total flow to 15 bar—70% eff. (MWh)	2,698	5,218

* Only a part of this (~75 %) can be used for LPG because of the gas composition
** Compression necessary for power production at the field

Investment Cost

	% Investment million US$	100% is used for sensitivity analyses
Alternative 1		
Gas compression at Yuca	***1.20***	1.2
Gas compression at Yulebra	***0.80***	0.8
Gas pipeline from Yuca to Yulebra, 15 km	***0.30***	0.3
Gas generating plant - 7 MW Electricity	***4.30***	4.3
Power connection: Yulebra - Coca, 7 MW and 20 km	***0.40***	0.4
	7.00	**6.9**
Alternative 1 + LPG		
Gas compression at Yuca	***1.20***	1.2
Gas compression at Yulebra	***0.80***	0.8
Gas pipeline from Yuca to Yulebra, 15 km	***0.30***	0.3
Gas generating plant—6 MWElectricity	***3.70***	3.7
Power connection: Yulebra - Coca, 6 MW and 20 km	***0.40***	0.4
Gas dehydration	***1.70***	1.7
Gas chilling	***0.70***	0.7
Distillation, storage, and so forth	***0.50***	0.5
	9.30	**9.3**
Alternative 2		
Gas compression at Yuca	***1.20***	1.2
Gas compression at Yulebra	***0.80***	0.8
Gas generating plant at Yuca—5 MWElectricity	***3.30***	3.3
Gas generating plant at Yulebra—2 MWElectricity	***2.10***	2.1
Power connection:Yuca - Yulebra, 5 MW and 15 km	***0.60***	0.6
Power connection:Yulebra - Coca, 7 MW and 20 km	***0.35***	0.4
	8.35	**8.4**

Alternative 0—Flaring of All Associated Gas

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Associated Gas Production																	
Production at Yuca	million m^3/year	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Production at Yulebra	million m^3/year	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
CO_2 from flaring																	
CO_2 from Yuca gas	tons	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423	25,423
CO_2 from Yulebras gas	tons	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240	12,240
Total CO_2 emission from flaring	tons	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663	37,663
NPV of CO_2 emission	**262,664**	**tons**															
Total Economic Cost of Flaring																	
Cost of CO_2 emission	million US$	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Net Benefit of Flaring	**(5.25) million US$**																

Alternative 1—Transport of Gas and Power Production at Yulebra

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Associated Gas Production																	
Production at Yuca	million m^3/year	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Production at Yulebra	million m^3/year	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Power Production																	
Production from Yuca gas	MWh	0	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218
Present use at Yuca	MWh	0	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953
Power for gas compression at Yuca	MWh	0	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958
Transmission to Coca via Yulebra	MWh	0	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308	22,308
Production from Yulebra gas	MWh	0	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287
Present use at Yulebra	MWh	0	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043
Power for gas compression at Yulebra	MWh	0	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698
Transmission to Coca	MWh	0	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547
Total power supply to Coca	MWh	0	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854	34,854

Alternative 1—Transport of Gas and Power Production at Yulebra—Economic Analyses

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression at Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression at Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas pipeline from Yuca to Yulebra	million US$	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generator plant at Yulebra, 7 MW	million US$	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**7.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
2% of total investment	million US$	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Cost of flaring	million US$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total O&M	**million US$**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Total Cost	**million US$**	**7.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
NPV of Total Costs	**7.10**		**million US$**														
Saved Economic Cost																	
Saved cost of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved cost of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Saved cost of diesel in Coca	million US$	-	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44
Saved CO_2 cost of power production	million US$	-	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Saved CO_2 cost from flaring	million US$	-	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Total Saved Costs	**million US$**	-	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07	4.07
NPV of Benefits	**24.74**	**million US$**															
Net Benefits	**million US$**	-7.0	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93
Net Benefits of Alternative 1	**17.64**	**million US$**															
E-IRR of Net Benefits	**56%**																

Financial Analyses (field operator's perspective)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression at Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression at Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas pipeline from Yuca to Yulebra	million US$	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generator plant at Yulebra, 7 MW	million US$	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**7.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
2% of total investment	million US$		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total O&M	**million US$**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Total Cost	**million US$**	**7.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
NPV of Total Costs	**6.80**	**million US$**															
Income																	
Saved puchase of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved purchase of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Sales price of electricity in Coca	million US$	-	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44	2.44
Total Income	**million US$**	**-**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
NPV of Income	**16.09**	**million US$**															
Net Income	**million US$**	**-7.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**
Net Income of Alternative 1	**9.29**	**million US$**															
F-IRR of Net Income	**43%**																

Alternative 2—Power Production at Yuca and Yulebra

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Associated Gas Production																	
Production at Yuca	million m^3/year	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Production at Yulebra	million m^3/year	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Power production																	
Production at Yuca	MWh	0	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218	36,218
Present use at Yuca	MWh	0	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953
Power for gas compression at Yuca	MWh	0	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218	5,218
Transmission to Coca via Yulebra	MWh	0	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047	24,047
Production at Yulebra	MWh	0	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287	18,287
Present use at Yulebra	MWh	0	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043
Power for gas compression at Yulebra	MWh	0	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698
Transmission to Coca	MWh	0	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547	12,547
Total transmission to Coca	MWh	0	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594	36,594

Economic Analyses

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression at Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression at Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yuca, 5 MW	million US$	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yulebra, 2 MW	million US$	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yuca - Yulebra)	million US$	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**8.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
2% of total investment	million US$	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Cost of flaring	million US$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total O&M	**million US$**	**0.0**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Total Cost	**million US$**	**8.4**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
NPV of Total Costs	**8.47**	**million US$**															
Saved Economic Cost																	
Saved cost of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved cost of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Saved cost of diesel in Coca	million US$	-	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Saved CO_2 cost of power production	million US$	-	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Saved CO_2 cost from flaring	million US$	-	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Total Saved Costs	**million US$**	**-**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**	**4.19**
NPV of Benefits	**25.48**	**million US$**															
Net Benefits	**million US$**	**-8.4**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**	**4.02**
Net Benefits of Alternative 2	**17.00**	**million US$**															
E-IRR of Net Benefits	**48%**																

Financial Analyses (field operator's perspective)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression at Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression at Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yuca, 5 MW	million US$	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yulebra, 2 MW	million US$	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yuca - Yulebra)	million US$	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**8.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
2% of total investment	million US$	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total O&M	**million US$**	**0.0**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Total Cost	**million US$**	**8.4**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
NPV of Total Costs	**8.11**	**million US$**															
Income																	
Saved purchase of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved purchase of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Sales price of electricity in Coca	million US$	-	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Total Income	**million US$**	**-**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
NPV of Income	**16.70**	**million US$**															
Net Income	**million US$**	**-8.4**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
Net Income of Alternative 2	**8.59**	**million US$**															
F-IRR of Net Income	**37%**																

Alternative 1 plus LPG—Power Production and LPG Production at Yulebra

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Associated Gas Production																	
Production at Yuca	million m^3/year	0	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Production at Yulebra	million m^3/year	0	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
LPG production from Associated Gas																	
LPG production from Yuca gas	million m^3/year	0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
LPG production from Yulebra gas	million m^3/year	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
LPG production from Yuca gas	ton	0	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102
LPG production from Yulebra gas	ton	0	549	549	549	549	549	549	549	549	549	549	549	549	549	549	549
Total LPG production	ton	0	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651	2,651
Gas amounts for electricity production																	
Amounts at Yuca	million m^3/year	0.0	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Amounts at Yulebra	million m^3/year	0.0	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Power production																	
Production from Yuca gas	MWh	0	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519	26,519
Present use at Yuca	MWh	0	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953	6,953
Power for gas compression at Yuca	MWh	0	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958	6,958
Transmission to Coca via Yulebra	MWh	0	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609	12,609
Production from Yulebra gas	MWh	0	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757	15,757
Present use at Yulebra	MWh	0	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043	3,043
Power for gas compression at Yulebra	MWh	0	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698	2,698
Transmission to Coca	MWh	0	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016	10,016
Total power transmission to Coca	MWh	0	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624	22,624

Economic Analyses

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression of - Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression of - Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas pipeline from Yuca to Yulebra	million US$	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yulebra, 6 MW	million US$	3.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dehydration of gas	million US$	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chilling of gas	million US$	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distillation, storage etc.	million US$	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**9.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
5% of total investment	million US$	-	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cost of flaring	million US$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total O&M	**million US$**	**0.0**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Total Cost	**million US$**	**9.3**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
NPV of Total Costs	**11.13**	**million US$**															
Saved Economic Cost																	
Saved cost of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved cost of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Saved cost of diesel in Coca	million US$	-	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Saved cost of LPG imports	million US$	-	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
Saved CO_2 cost of power production	million US$	-	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Saved CO_2 cost from flaring	million US$	-	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Total Saved Costs	**million US$**	**-**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**	**3.54**
NPV of Benefits	**21.53**	**million US$**															
Net Benefits	**million US$**	**-9.30**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**	**3.08**
Net Benefits of Alternative 1 plus LPG	***10.40***	***million US$***															
E-IRR of Net Benefits	***33%***																

Financial Analyses (field operator's perspective)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Investment Cost																	
Gas compression of - Yuca	million US$	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas compression of - Yulebra	million US$	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas pipeline from Yuca to Yulebra	million US$	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas generation plant at Yulebra, 6 MW	million US$	3.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power transmission (Yulebra - Coca)	million US$	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dehydration of gas	million US$	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chilling of gas	million US$	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distillation, storage etc.	million US$	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	**million US$**	**9.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
O&M Cost																	
5% of total investment	million US$	-	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total O&M	**million US$**	**0.0**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Total Cost	**million US$**	**9.3**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
NPV of Total Costs	**10.45**	**million US$**															
Income																	
Saved purchase of diesel at Yuca oil field	million US$	-	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Saved purchase of diesel at Yulebra oil field	million US$	-	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Sales of electricity in Coca	million US$	-	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Sales of LPG	million US$	-	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
Total Income	**million US$**	**-**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
NPV of Income	**15.99**	**million US$**															
Net Income	**million US$**	**-9.3**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**
Net Income of Alternative 1 plus LPG	**5.54**	**million US$**															
F-IRR of Net Income	**28%**																

Results of Economic Analysis

US$20 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Alternative 1 - Transport of Gas and Power Production at Yulebra	24.7	7.1	17.6	0	100	56
Alternative 2 - Power Production at Yuca and Yulebra	25.5	8.5	17.0	0	100	48
Alternative 1 plus Production of LPG	21.5	11.1	10.4	0	100	33

US$7 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Alternative 1 - Transport of Gas and Power Production at Yulebra	21.2	7.1	14.1	0	100	44
Alternative 2 - Power Production at Yuca and Yulebra	21.9	8.5	13.4	0	100	41
Alternative 1 plus Production of LPG	18.0	11.1	6.8	0	100	24

US$0 per ton CO_2—Abatement Cost of CO_2

NPV million US$	Benefits	Costs	Net Benefits	NPV of CO_2 emission ton CO_2	Abate Cost Total US$/ton	Abate-Cost Net US$/ton
Alternative 1 - Transport of Gas and Power Production at Yulebra	19.2	7.1	12.1	262,664	27	-46
Alternative 2 - Power Production at Yuca and Yulebra	20.0	8.5	11.5	262,664	32	-44
Alternative 1 plus Production of LPG	16.0	11.1	4.9	262,664	42	-19

Results of Financial Analysis

NPV million US$	Income	Costs	Net Income	Gas Flared %	Gas Used %	F-IRR %
Alternative 1 - Transport of Gas and Power Production at Yulebra	16.1	6.8	9.3	0	100	43
Alternative 2 - Power Production at Yuca and Yulebra	16.7	8.1	8.6	0	100	37
Alternative 1 plus Production of LPG	16.0	10.5	5.5	0	100	28

Results of Economic Analysis—Sensitivity Analyses
Decrease of Energy Price by 20%

US$20 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Associated Gas Production	20.9	7.1	13.8	0	100	47
Associated Gas Production	21.5	8.5	13.0	0	100	40
Alternative 1 plus Production of LPG	18.3	11.1	7.2	0	100	27

US$7 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Associated Gas Production	17.3	7.1	10.2	0	100	44
Associated Gas Production	17.9	8.5	9.4	0	100	41
Alternative 1 plus Production of LPG	14.8	11.1	3.6	0	100	24

US$0 per ton CO_2

				Abatement Cost of CO_2		
NPV million US$	Benefits	Costs	Net Benefits	NPV of CO_2 emission ton CO_2	Cost Total US$/ton	Cost Net US$/ton
Associated Gas Production	15.4	7.1	8.3	262,664	27	-32
Associated Gas Production	16.0	8.5	7.5	262,664	32	-29
Alternative 1 plus Production of LPG	12.8	11.1	1.7	262,664	42	-6

Results of Financial Analysis

NPV million US$	Income	Costs	Net Income	Gas Flared %	Gas Used %	F-IRR %
Associated Gas Production	12.9	6.8	6.1	0	100	34
Associated Gas Production	13.4	8.1	5.3	0	100	29
Alternative 1 plus Production of LPG	12.8	10.5	2.3	0	100	21

Results of Economic Analysis—Sensitivity Analyses

Increase of Investment by 20%

US$ 20 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Associated Gas Production	24.7	8.5	16.2	0	100	46
Associated Gas Production	25.5	10.2	15.3	0	100	40
Alternative 1 plus Production of LPG	21.5	13.4	8.2	0	100	26

US$7 per ton CO_2

NPV million US$	Benefits	Costs	Net Benefits	Gas Flared %	Gas Used %	E-IRR %
Associated Gas Production	21.2	8.5	12.6	0	100	39
Associated Gas Production	21.9	10.2	11.7	0	100	34
Alternative 1 plus Production of LPG	18.0	13.4	4.6	0	100	20

US$0 per ton CO_2

				Abatement Cost of CO_2		
NPV million US$	Benefits	Costs	Net Benefits	NPV of CO_2 emission ton CO_2	Cost Total US$/t on	Cost Net US$/t on
Associated Gas Production	19.2	8.5	10.7	262,664	32	-41
Associated Gas Production	20.0	10.2	9.8	262,664	39	-37
Alternative 1 plus Production of LPG	16.0	13.4	2.7	262,664	51	-10

Results of Financial Analysis

NPV million US$	Income	Costs	Net Income	Gas Flared %	Gas Used %	F-IRR %
Associated Gas Production	16.1	8.2	7.9	0	100	35
Associated Gas Production	16.7	9.7	7.0	0	100	30
Alternative 1 plus Production of LPG	16.0	12.5	3.4	0	100	22

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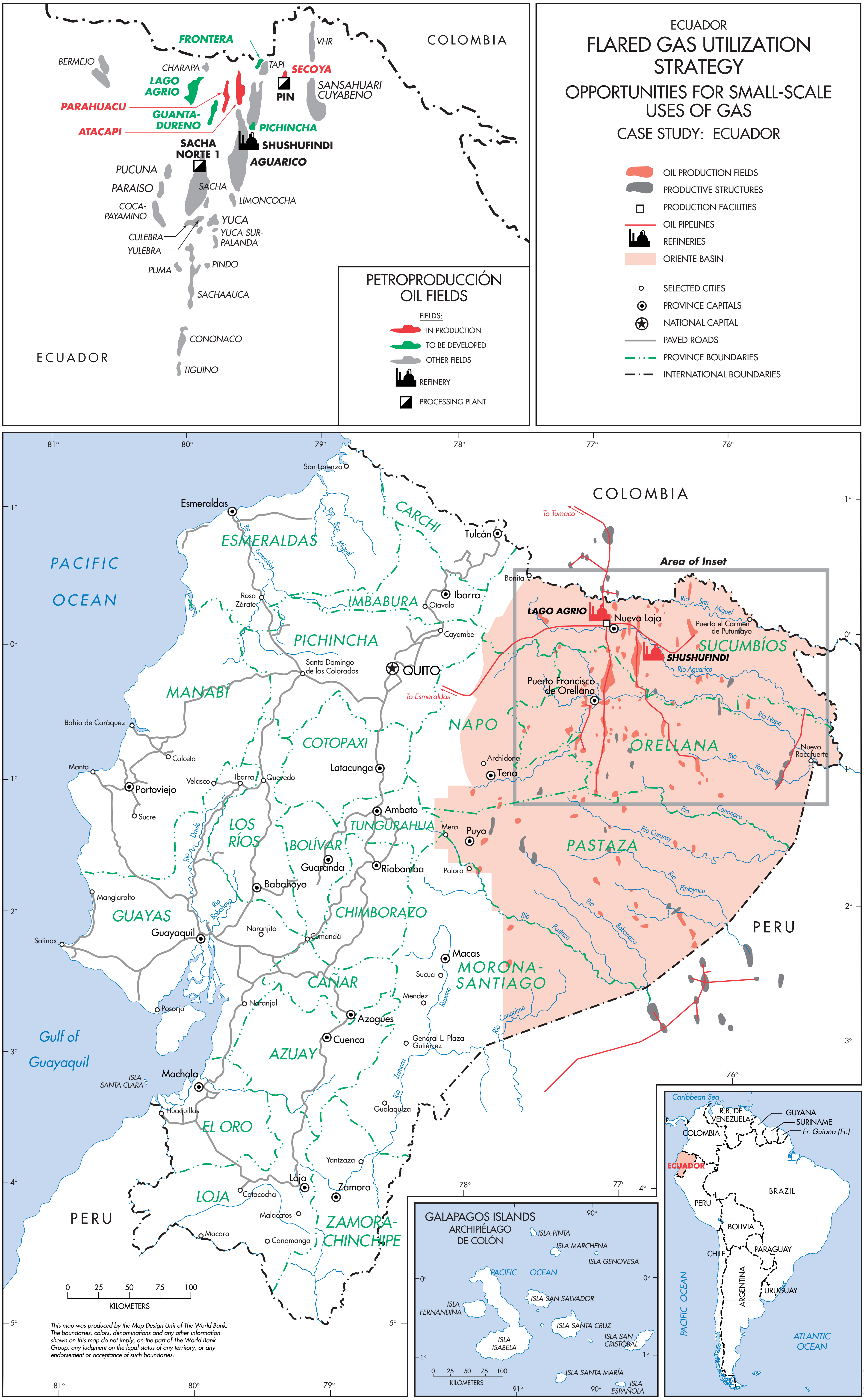

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