Securing Energy Supply and Enlarging Markets through Cleaner Fossil Technology

SESEM – CFT

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A Review of the Power Sector in Latin America and the Caribbean, Evolution in the Market and Investment Opportunities for CFTs

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1 Introduction

A consortium comprising of Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas (Co-ordinator), Forschungszentrum Jülich GmbH / Projektträger Jülich, VGB PowerTech e.V., European Power Plant Suppliers' Association, Gray Associates and Deutsche Montan Technologie GmbH, has been awarded with a contract from the European Commission towards the implementation of the project “Securing Energy Supply and Enlarging Markets through Cleaner Fossil Technology”, hereinafter referred to as ”SESEM”. In the framework of the EU- LAC political dialogues and cooperation agreements the SESEM project is designed to highlight and promote the opportunities in the LAC energy market for priority investments for cleaner fossil fuel technology (CFT).

The study is aimed at decision makers from politics and power industry in the European Union (EU) and Latin America and the Caribbean (LAC) in order to make them familiar with the characteristics of the respective other market. **Chapter 2** provides the reader with a quick overview on the results of the study. At one glance the reader may catch the key findings in the consecutive sequence of the chapters. Afterwards he may directly refer to the chapter that is of most interest to him.

Chapter 3 introduces the reader to the political framework of the ongoing dialogues and activities between the EU and the LAC region that have already lead to several cooperation agreements. In order to make the energy political background of both regions more transparent, the respective energy policies are highlighted in terms of competitiveness, energy supply security and environmental protection for the EU and in terms of market liberalisation and environmental protection for the LAC region. Thus the study contributes to the mutual understanding of the structure and the functioning of both energy markets. This understanding is essential as both regions strongly enhance their cooperation through signing Association Contracts.

Environmental policy in LAC is heavily influenced by the international community. For the power generation sector actual environmental legislation is described and assessed. The development in the short term future is identified. This action describes the legal environment for energy investments in LA.

The perspectives of the fossil fuel energy markets of the EU and LAC are described in **Chapter 4**. It addresses the growing supply dependency of the EU on natural gas and oil and the political activities undertaken to mitigate the implications. The energy perspectives of the LAC region, on the other hand, are also driven by natural gas and oil, especially for the large scale power generation. Strategies of both regions to comply with the respective energy requirements of the domestic energy markets are presented to make the reader well-known with the driving forces in the background.

A review of the LAC power market has been performed in **Chapter 5** describing its structure and functioning as well as energy demand and supply scenarios in order to define the capacity of the market and describe its development. Based on a database prepared by OLADE fossil fuel power plant technologies presently used in LAC were scrutinised with the support of our partner OLADE. Studies already done or being under preparation (e.g. Synergy) were also considered.

This Chapter clearly points out that there is a high activity by the EU CFT industry in the LAC region identifying the share of international stakeholders including many from the EU in LAC power generation and distribution companies. The involvement of Southern European companies such as

Endesa, Iberdrola, Union Fenosa, EdP, EdF, Tractebel, etc. in the LAC region may serve of providing management in the LAC, technology transfer and exporting of EU CFT hardware to LAC markets.

LAC decision makers shall be informed through **Chapter 6** about commercially available state-of-the-art CFT technologies from the EU which may find application in their power market in order to generate power with high efficiency and availability as well as lowest emissions. Only state-of-the-art technologies that correspond to the LAC power market requirements are selected and presented.

Finally, **Chapter 7** provides the EU decision-makers from industry and politics with information on potentials for CFT investment in the LAC fossil fuel energy sector. In the Priority Action Plan (PAP) fuel exploration and exploitation, upgrading and combustion technologies, rehabilitation of existing power plants and potential new power plant projects are evaluated regarding their CFT investment potentials in the short and medium term.

Based on the evaluation of the LAC power market in chapter 5 the short to medium term technological requirements of the LAC power sector are derived. In this context of potential priority investment opportunities for large-scale power production in LAC a specific investment project has been identified and described in agreement with our Latin American partner OLADE. This project shall receive special consideration of the European Commission (EC) as it complies with several energy political issues of the LAC region and is located in Central America, a region where already an Association Agreement is in force which also tackles the energy sector.

The project will be presented and promoted to investors, financing organisations and politics in the upcoming events of the SESEM LAC Energy Conference in Mexico in February 2005 and the final SESEM Conference in Brussels in December 2005.

It is assumed that during the last year of the project further interesting potential investment projects are identified and selected with support of OLADE and industrial LAC partners. Project descriptions will be prepared to attract and convince investors and financing organisations to invest into the project. These projects will be made transparent at the Final Conference in Brussels in December 2005.

2 Key findings

The following summary of key findings shall enable the reader to obtain a quick overview of the most important facts in the LAC power sector. More detailed information on the subjects will be available in the chapters of the study.

Policies related to the energy markets in EU and LAC

- The European Union (EU) is Latin America's (LA) second most important trading partner and most important source of foreign investment.
- The EU has concluded Association Agreements with Central America, the Andean Community and Mexico.
- The EU has signed Agreements for Science and Technological Cooperation with Chile, Brazil and Mexico.
- The EU energy policies are targeting at liberalised energy markets to enforce competitiveness, security of energy supplies and protection of the environment against the adverse effects of energy utilisation.
- Latin America and the Caribbean have started power sector reforms in the beginning of the 1990s which, however, have not been completed in some countries.
- Argentina, Bolivia, Guatemala, Panama, Chile, El Salvador, Peru, Dominican Republic Colombia, Brazil, Nicaragua have open power markets with structures from fully private up to mixed (private/state) ownership structures.
- In the course of the power sector reforms environmental legislation has entered into force demanding environmental impact assessment studies to be performed prior to any power sector investment project.
- Regulations on emission reduction from power generation are not in place. It accounts for 8% of the world's CO_2 emissions. Since the region has received the "developing country" status in the Kyoto Annexes it is not obligated to reduce existing emissions.
- 26 countries from Latin America and the Caribbean (LAC) have signed the Framework Convention on Climate Change, 23 have signed the Kyoto Protocol and in 20 countries the respective National Authorities for the Clean Development Mechanism is in operation.
- Latin American countries provide significant opportunities for CDM project investments.
- A variety of LAC countries have CDM projects in the pipeline including also projects on fossil fuels.

Perspectives of the EU and LAC energy markets

- The European Union represents around 16% of the world energy market and is the largest net energy-importing region in the world in absolute terms.
- Installed EU power generation capacity is projected to increase by nearly 60% from 1999 to 2030 (incl. new member states).

- Over half of existing power plants are expected to be decommissioned until 2030. Most new capacity is expected to be gas-fired, particularly in combined-cycle gas turbine (CCGT) plants.
- EU25 will suffer a significant growth of energy import dependency from 47.1% in 2000 up to 67.5% in 2030, an increase of more than 20%.
- Coal consumption will become increasingly concentrated in power generation and specialised industrial uses, such as steel-making. The power sector will account for 80 % of primary coal use by 2030 compared to 76 % in 2000, and the industrial sector will take almost all of the rest.
- Despite the continuing contraction of the EU coal market, demand will be increasingly met with imports, as indigenous production declines even more rapidly.
- Natural gas consumption in EU has grown more in absolute terms than that of any other fuel over the past three decades, and this trend will continue to 2030. The share of gas in total primary energy demand will continue to rise from 23 % in 2002 to 32 % in 2030.
- Oil will remain Europe's largest energy source, with primary oil demand increasing by 0.5% per year from 2000 to 2030. Almost all demand will come from the transport sector.
- The LAC region has 10% of the world's oil reserves, 4.3% of the world's natural gas reserves, and 1.6% of the world's coal reserves. Moreover, 22.7% of the world's hydroelectric potential is found in the LAC region.
- In 2003 the energy demands of Latin America and the Caribbean constitute approximately 6.6% of the world energy market.
- The region has sufficient energy reserves for its consumption needs and for export to other regions of the world; based on actual consumption (basis: year 2003 and proven reserves) the total reserves of oil and gas, however, would serve the demand for no more than 30 years.
- Energy strategies of Latin America and the Caribbean are focused to increase the access of the population and industry to power.
- To achieve the projected high coverage of power access it is necessary to install rural electrification and the use of renewable energy in remote areas.
- Natural gas is the main fuel for power production and its role will even be strengthened in the future.
- The distribution and access to natural gas will be enforced by strengthening the pipeline network system in the region.
- Countries of the Southern Cone have indicated the intention to refurbish oil fired power stations to gas fired power stations.
- In the LAC region coal actually only plays a minor role as an energy source for power production; however, with the depletion of oil and natural gas reserves in about 30 years, coal may gain a more preferential position in the power sector.
- Hydropower represents a strong option for power generation in LAC and will play an important role in the energy mix of the region for the long term.

<u>The LAC power market</u>

- The installed electrical generation capacity of the LAC region totals approximately 253 GW in 2003.
- In 2003 52% of the installed power is hydroelectric, 45% is thermoelectric, 2% is nuclear, and 1% utilizes sources such as geothermal, wind, solar and biomass.
- Power production in the 26 OLADE countries was 1,021 TWh in 2003, an increase of 42.5 TWh (4.3%) compared to 2002.
- The power market is growing by 4-5% p.a., i.e. approximately 12 GW p.a.
- Many LAC countries report high level of transmission and distribution power losses which is in average about 19% for the region.
- Power consumption in Latin America and the Caribbean was 820.7 TWh in 2003, an increase of 34.2 TWh (4.3%) compared to 2002.
- Coal met only 5% of primary energy demand in Latin America in 2003, of which 65% was used in Brazil. Latin America has proven recoverable coal reserves of 16 billion tons.
- About 42% of coal production is dedicated for export to the EU and United States.
- LAC‘s proven natural gas reserves amounted to 7.5 10^{12} m^3 in 2003, 5% of the world’s total.
- Venezuela holds 54% of the proven reserves, followed by Bolivia (10%), Argentina (10%), Mexico (8%) and Trinidad and Tobago (7%).
- LAC’s natural gas production in 2003 was 197 10^9 m^3. Production is expected to expand significantly over the next three decades, reaching 516 10^9 m^3 in 2030.
- The region‘s proven oil reserves stood at 114.5 billion barrels at the end of 2003, i.e. 10% of the world’s total.
- LAC’s production of crude oil and LNG averaged 9.4 mb/d in 2003 and is expected to increase to almost 12 mb/d by 2030. Production is dominated at present by Venezuela, Mexico and Brazil.
- Compared to the world oil refining capacities LAC has a share of almost 9%.
- South European and US companies dominate the LAC power sector.
- The involvement of Southern European companies such as Endesa, Iberdrola, Union Fenosa, EdP, EdF, Tractebel, etc. in the LAC region may serve of providing management in the LAC, technology transfer and exporting of EU CFT hardware to LAC markets.
- Electricity tariffs in many countries allow the utilities to make profit. However, political uncertainties and legal framework instabilities in the region cause financial risk.
- The LAC region is split into 2 operating power networks with different frequencies: the southern countries operate on 50 Hz whereas the northern countries operate on 60 Hz.
- LAC countries are moving towards integration of the power networks, including the Central Americans countries, through the implementation of the SIEPAC (Sistema de Interconexión Eléctrica de los Países de América Central – System of power interconnection in the Central American countries) project under the Framework Agreement of the Central American Electrical Market and the creation of the Regional Electricity Market.

- The main types of power plants technologies applied are gas fired turbines and gas or oil fired boilers with steam turbines; however, power generation by combined cycle gas turbine technology will obtain more and more shares in the region.
- In order to meet the growth of power demand annually roughly 12 GW of new power plants have to be installed.
- The evaluation of the power plant technologies in LAC has been derived from the Energy-Economic Information System (SIEE) operated by OLADE.
- In the LAC 73% of the power plants have nominal outputs less than 50 MW, 23% are in the range of 50 to 400 MW and 4% are in the range of between 400 to 1000 MW.
- In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam or gas turbines.
- Gas turbines account for 27%, steam turbines for 56%, gas combined cycle plants contribute 7% and diesel engines 6% of the power generation. The balance of 4% is made up by geothermal and nuclear power plants.
- 85% of the power generation is based on oil and natural gas. Coal actually plays no major role in the LAC power sector although large reserves are present in the region.
- A replacement potential of actually around 9 GW can be identified for the running decade.

EU CFT technologies – options for the LAC power market

- Adequate EU CFT technologies for large scale power generation corresponding to the LAC power market needs comprise gas and steam turbine plants as well as combined-cycle plants running on natural gas.
- Options for the longer term (>20 years) include pulverised coal combustion and IGCC plants – for the time when the oil and gas reserves of the region start to deplete.
- For small-to medium-power outputs (up to approximately 30 MW), a diesel generator power plant can be a genuine alternative. The high efficiency of modern diesel engines is slightly less than combined-cycle with the same rating.
- Whenever gas or oil is fired in a power station, the combined-cycle plant is more economical than the steam power plant due to its higher efficiency and lower specific price. Modern combined-cycle plants are simpler, less expensive, and operationally more flexible than steam power plants.
- For short utilization periods (peaking units), the gas turbine is most economical. Gas turbines can serve as intermediate - or base-load units in countries where fuel is abundant at low cost. The lack of water consumption has made this machine popular in dry regions. The short installation time allows a customer to plan a new installation on short notice.
- If all fuels are readily available at world market prices, gas fired combined-cycle plants are the most economical solution for intermediate- and base-load applications. This results in a limited environmental impact (small heat rejection or low water consumption). With clean fuels like natural gas, this technology also achieves lowest emissions.

- EU technologies offer retrofit options for emission reduction either by modifications of the burner design (low-NOx), the process design (air staging, reburning), plant control systems or by end-of-pipe pollution abatement and control technologies (e.g. filters, scrubbers, etc.).

Priority Action Plan

- Total private-sector investment in electricity between 1990 and 2002 in LA amounted to $97 billion, although this has been in decline in recent years.
- The reasons for the observed decline in private investment include badly designed economic reforms, economic crisis and bad business judgements.
- Investments in the electricity sector are dominated by the growth of power demand in Brazil.
- Brazil's electricity demand will increase by two-and-a-halftimes from 2000 to 2030, growing at an average annual rate of 3.2%. To meet this big increase, the country will need to invest more than $330 billion in the power sector, more than half in transmission and distribution networks.
- Cumulative coal investment of around $10 billion will be required in Latin America until 2030. Coal production in the region is expected to grow at 2.6% per annum, from almost 54 Mt in 2000 to 115 Mt in 2030.
- Cumulative investment needs in the Latin American gas sector are projected to total $247 billion, or more than $8 billion per year, over the period 2001-2030, amounting to 8% of global gas sector investment.
- Gas-sector policies will need to be integrated with electricity policies, as gas-to-power projects are the key to ensuring the financial viability of the gas chain.
- Investment in Latin America's oil sector is expected to be dominated by projects in Brazil and Venezuela. Total investment will amount to $336 billion over the period 2001-2030.
- On short to medium term (i.e. <15 years) new installations of power generation will be mainly based on natural gas and corresponding power generation technologies. The favourite technology will be highly efficient combined cycle gas turbines.
- There is a clear statement that actual priorities are given to push the economic growth of the region and that this priority is overruling any request of emission reduction from power generation.
- It is envisaged that in about 10 years emission reduction will be a strong subject of the region and refurbishment of power plants with regard to emission reduction facilities will become an issue.
- Because of the projected depletion of gas and oil reserves in about 30 years and the redundant availability of large coal reserves in the region, principally the clean coal based technology options PF combustion and IGCC may come to the fore in the longer term (>20 years).
- There are principally three main technology options for the fossil fuel fired power plant sector in LAC to be considered for the short to medium term (<15 years): combined cycle

gas turbine technology, refurbishment of oil to gas fired power plants, retrofitting of emission reduction facilities.

- The Priority Action Plan (PAP) identifies the construction of two large CCGT power generation plants on natural gas in Central America with a regional perspective, lending impetus and viability to the power interconnection of the SIEPAC Project.
- According to information provided by the countries through the CEAC, the Central American power sector is expected to grow over the next two decades at a rate of approximately 5.5% per year.
- The Central American region would require 200 MW in new power plants starting in 2005. During 2010, 2015 and 2020, the integrated system would need the availability of an additional 1,300, 3,500 and 5,100 MW, respectively.

3 Policies related to the energy markets in EU and LAC

Key findings:

- The European Union is Latin America's second most important trading partner and most important source of foreign investment.
- The EU has concluded Association Agreements with Central America, the Andean Community and Mexico.
- The EU has signed Agreements for Science and Technological Cooperation with Chile, Brazil and Mexico.
- The EU energy policies are targeting at liberalised energy markets to enforce competitiveness, security of energy supplies and protection of the environment against the adverse effects of energy utilisation.
- Latin America and the Caribbean have started power sector reforms in the beginning of the 1990s which, however, have not been completed in some countries.
- Argentina, Bolivia, Guatemala, Panama, Chile, El Salvador, Peru, Dominican Republic Colombia, Brazil, Nicaragua have open power markets with structures from fully private up to mixed (private/state) ownership structures.
- In the course of the power sector reforms environmental legislation has entered into force demanding environmental impact assessment studies to be performed prior to any power sector investment project.
- Regulations on emission reduction from power generation are not in place. It accounts for 8% of the world's CO_2 emissions. Since the region has received the "developing country" status in the Kyoto Annexes it is not obligated to reduce existing emissions.
- 26 LAC countries have signed the Framework Convention on Climate Change, 23 have signed the Kyoto Protocol and in 20 countries the respective National Authorities for the Clean Development Mechanism is in operation.
- Latin American countries provide significant opportunities for CDM project investments.
- A variety of LAC countries have CDM projects in the pipeline including also projects on fossil fuels.

The European Union is Latin America's second most important trading partner. The European Union has gradually strengthened its economic and trade links with Latin America, resulting in trade figures that more than doubled between 1990 and 2002. European Union imports from Latin America increased from € 26.7 to € 53.7 billion, and exports to the region rose from € 17.1 to € 57.5 billion[1]. This positive trend is bound to be reinforced thanks to the enlargement of the European Union which has become, as from 1st May 2004, an integrated market of 455 million inhabitants. The European Union will thus become the biggest market in the world, offering

[1] These figures include the Andean Community, the Caribbean region, Central America, Chile, Cuba, Dominican Republic, Haiti, Mercosur and Mexico

enormous possibilities for Latin American countries to sell their products to a wider range of consumers.

The European Union is also the most important source of foreign direct investment (FDI) for Latin America. Flows of European FDI to Latin America peaked in 2000 and have since diminished. However, the total stock of European investment in Latin America grew from € 176.5 billion in 2000 to € 206.1 in 2002 [2].

Last, the European Union is the leading donor of development assistance for Latin America. In addition to the contributions from the Member States, since 1996 the European Community budget for Latin America has totalled more than € 500 million [3] per year. Furthermore, between 2000 and 2003 the European Investment Bank invested € 1,104 million in the form of loans for projects of mutual interest to the countries of the European Union and Latin America.

3.1 Political dialogue between EU and LAC

The first Summit between the Heads of State and Government of Latin America, the Caribbean and the European Union was held in the city of Rio de Janeiro on 28 and 29 June 1999. The Summit was convened as a result of the political will to enhance bi-regional relations and its objective was to strengthen political, economic and cultural understanding between the two regions in order to develop a strategic partnership.

The three strategic dimensions of this partnership are:

- a fruitful political dialogue respectful of international law and based on the strong attachment of both regions to multilateralism;
- solid economic and financial relations based on a comprehensive and balanced liberalisation of trade and capital flows; and
- more dynamic and creative co-operation in the educational, scientific, technological, cultural, human and social fields.

On 17 May 2002, the second Summit of Heads of State and Government of the European Union, Latin America and the Caribbean took place in Madrid. This Summit consolidated the process which begun in Rio de Janeiro and confirmed both regions' commitment to the development of the bi-regional strategic partnership.

The Summit marked the conclusion of the Association Agreement (COM(2002) 536) with Chile, which was finally signed in November 2002.

Moreover, the Madrid Summit declaration gave a political mandate for the negotiation of political dialogue and cooperation agreements with the Andean Community and Central America. In December 2003 the European Union concluded negotiations and signed the Political Dialogue and Cooperation Agreements with both regions in Rome.

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[2] These figures include the Andean Community, the Caribbean region, Central America, Chile, Cuba, Dominican Republic, Haiti, Mercosur and Mexico

[3] These figures include the Andean Community, the Caribbean region, Central America, Chile, Cuba, Dominican Republic, Haiti, Mercosur and Mexico

In Article 25 of the Association Agreement with Central America[4] (COM(2003) 677) the energy cooperation is defined as follows:

1. The Parties agree that their joint objective will be to foster cooperation in the field of energy, in key sectors such as hydroelectricity, electricity, oil and gas, renewable energy, energy saving technology, rural electrification and regional integration of energy markets, among others as identified by the Parties, and in compliance with domestic legislation.

2. Cooperation may include, among others, the following:

(a) formulation and planning of energy policy, including inter-connected infrastructures of regional importance, improvement and diversification of energy supply and improvement of energy markets, including facilitation of transit, transmission and distribution within the Central American countries;

(b) management and training for the energy sector and transfer of technology and know-how;

(c) promotion of energy saving, energy efficiency, renewable energy and studying of the environmental impact of energy production and consumption;

(d) promote the application of clean development mechanism to support the climate change initiatives and its variability;

(e) the issue of clean and peaceful uses of nuclear energy.

In Article 25 of the Association Agreement with the Andean Community[5] (COM(2003) 695) the energy cooperation is defined as follows:

1. The Parties agree that their joint objective will be to foster cooperation in the field of energy, including consolidating economic relations in key sectors such as hydroelectricity, oil and gas, renewable energy, energy-saving technology, rural electrification and regional integration of energy markets, taking into consideration that the Andean countries are already implementing electricity interconnection projects.

2. Cooperation may include the following, in particular:

(a) energy policy issues, including interconnected infrastructure of regional importance, improvement and diversification of supply and improvement of access to energy markets, including facilitation of transit, transmission and distribution;

(b) management and training for the energy sector and transfer of technology and know-how;

(c) promotion of energy saving, energy efficiency, renewable energy and study of the environmental impact of energy production and consumption;

(d) cooperation initiatives between undertakings in this sector.

In addition to the above mentioned Association Agreements the EU signed agreements for scientific and technological cooperation with Chile (COM(2002) 0151), Brazil (COM(2003) 0381) and Mexico (COM(2003) 0438).

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[4] Central America; here: Republics of Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama

[5] Andean Community; here: the Republics of Bolivia, Colombia, Ecuador, Peru and the Bolivarian Republic of Venezuela

On 28 - 29 May 2004, the third Summit of Heads of State and Government of the European Union, Latin America and the Caribbean took place in Guadalajara. The Summit took decisions aimed at social cohesion and regional integration of the LAC countries. The Summit paved the way towards the opening of negotiations on Association agreements with Central America and the Andean Community, including Free Trade Agreements (FTA's) and the intensification of negotiations with Mercosur[6] for an Association Agreement in order to enable the negotiations to be concluded by October 2004.

In the Declaration of Guadalajara the Heads of State and Government of Latin America and the Caribbean stressed their commitment to promote energy efficiency and to increase the use of renewable energies as an important element in the pathway towards sustainable development. The participating countries welcomed the Renewable Energy and Energy Efficiency Partnerships and the Johannesburg Renewable Energy Coalition and encouraged countries that have not signed up to them to consider doing so. This process has been followed up at the Renewable Energy and Energy Efficiency Partnerships Conference in Bonn, Germany from June 1-4, 2004.

Moreover, they decided to explore new ways to produce energy such as those based on hydrogen and fuel cells as well as ways to undertake joint research efforts in this area.

3.2 Energy policy in EU

The first step towards a common European energy policy was taken with the Treaty establishing the European Atomic Energy Community (Euratom), which was signed in 1957 as one of the two founding treaties of the European Communities (Treaties of Rome). Its aim was to create the conditions necessary for the development of a powerful nuclear industry in Europe, at a time when nuclear was considered the prime energy source of the future.

However, the process of opening up the energy sector to competition began much later than for other sectors of the economy. The main obstacles to this were differing domestic energy sources and requirements plus the existence of large, state-owned, monopolistic energy industries in each of the Member States. Moreover, as energy policy had no legal basis in the Treaties of Maastricht, Amsterdam or Nice, the Commission had little scope to push for measures and, therefore, the energy policy developed under the umbrella of several different policies (external relations, internal market, environment) and different decision-making procedures.

The aftermath of the 1973 oil crisis revealed Europe's dependence on outside energy sources and therefore its vulnerability. Furthermore, it became clear that the energy sector could no longer be isolated from the increasingly integrated Single Market. This brought about a rapid evolution in a common energy policy, focusing on three basic objectives:

- Developing an internal market in energy
- Developing external energy relations and ensuring security of supply
- Minimising the negative impact of energy use and production on the environment.

Transparency, consistency and predictability of government policies form the backbone of successful energy market development. A comprehensive Community policy on energy aims at economic and social cohesion and seeks to increase the transparency and coherence of co-

[6] Mercosur - countries of Argentina, Brazil, Paraguay, Uruguay

operation between member states. The three above mentioned core objectives of the EU energy policy are strongly interrelated. Improvements in energy efficiency should benefit security of supply, by reducing the amount of energy consumed, and abate emissions of greenhouse gases and other pollutants, by reducing the consumption of fossil fuels. Market liberalisation and additional price competition will benefit competitiveness through reduced prices, but may act as a disincentive to energy saving and encourage consumption unless external costs are fully internalised and energy demand is better managed.

The European Commission has already set the wheels in progress with measures to increase energy efficiency, manage demand for imported oil, action to boost renewable energy use and maintain the nuclear option open. But EU success will be measured by the efforts which are made by Member States, Europe's industry and individual consumers. Below, is the description of the measures taken by the EU in order to meet the three core goals of the energy policy.

3.2.1 Competitiveness in the internal EU energy market

One of the prime objectives of the EU's energy strategy is the creation of conditions for a market-oriented economy through the liberalisation of the internal market for energy. A free European market, unhindered by cross border controls and national tariffs, is one of the founding ideals of the European Union. The EU has adopted a number of measures resulting in the creation of the internal market, especially for gas and electricity, with an initial effect of substantially reducing prices. After several years of discussions, the liberalisation of the electricity market began in 1996 and that of the natural gas market in 1998. As a result two-thirds of the market in electricity and 80% of the market in natural gas has been opened up. After intensive discussion between the Commission, the Council and the European Parliament it has been agreed that the electricity and gas markets should be completely opened up by 2007. The aim was to create single markets for electricity and gas which encompass the whole EU and not to perpetuate separated markets.

The most important issues are tariffs for cross border trade and dealing with scarce interconnection capacity. Cross-border, liberalised energy markets are better suited to bring about a sustainable increase in the wealth of different populations and countries, and so to all of Europe. One of the main driving forces behind opening of the electricity and gas markets is to bring down prices for consumers. Experience in the EU demonstrates that prices are already lowering since the start of market opening. As to the new Member States, it is expected that they will also in the long to medium term see the effects of the internal energy market. In addition, opening up the electricity and gas markets in the new EU Member States will improve their security of supply and economic efficiency.

The integration of the energy markets will be vital to the protection of energy consumers. Essential public services, such as ensuring supplies to all consumers, protecting the old and disadvantaged, can be better achieved in an open market. Service to the customer will be improved if energy suppliers have to compete for their clients. Competition in the energy sector will ultimately lead to new business and, therefore, employment opportunities for current and new players in the markets.

The enlargement of the European Union has created new challenges for the European Union's energy policy. The opening of the electricity and gas markets across the enlarged EU made these sectors more attractive to investors. The establishment of functioning energy markets in Europe will stimulate growth in both, the old and the new Member States. A key challenge will be to include the new EU Member States into the internal energy market in order to benefit from all the advantages associated with electricity and gas markets which are open to competition, the improvement of energy efficiency and the gradual introduction of renewable energy sources.

In the case of coal, operation of the market has been hindered by state help, principally in Germany, Spain and the United Kingdom. However, subsidies are being phased out and coal prices are being brought into line with international prices.

The EU electricity generation market was opened up to competition through a transparent authorisation procedure and introduced electricity supply competition by adopting the Directive 2003/54/EC of June 2003 concerning common rules for the internal market in electricity which repealed Directive 96/92/EC and 90/547/EEC. This Directive and Regulation (Regulation No.1228/2003 on conditions for access to the network for cross-border exchanges in electricity) are two elements of an energy liberalisation package that represents a major step towards the creation of a fully competitive, liberalised internal market in electricity and gas. The aim was to speed up liberalisation in the electricity sector with a view to achieving a fully operational internal market. The key elements include an obligation to allow industrial and commercial electricity and gas consumers a choice of supplier since 1 July 2004 and all consumers by July 2007. It also establishes common rules for separation of transmission and distribution from production and supply and access to grids and downstream pipelines on published, non-discriminatory terms. Such structural measures are essential to achieving properly functioning internal EU markets, which will bring benefits to consumers in terms of prices, efficiency, choice and service levels. Additionally, the EU Member States are required to establish independent economic regulators, with specific duties in relation for example to transmission and distribution tariffs. Such measures will make a major contribution to the reliability of energy supplies in the long term. The United Kingdom and Sweden introduced competition in electricity generation and in supply, based on third-party access, several years ago. Other countries have only recently implemented reforms in response to the adopted directive.

The EU established common rules for the transmission, distribution, supply and storage of natural gas by adopting a Directive 2003/55/EC of June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC. The directive lays down the rules relating to the organisation and functioning of the natural gas sector, access to the market, the criteria and procedures applicable to the granting of authorisations for transmission, distribution, supply and storage of natural gas and the operation of systems.

The EU took also measures to reduce the distortions in competition that existed between energy products (only mineral oils have been subject to EU tax legislation and not coal, natural gas or electricity) by introducing an EU-wide system for the taxation of all energy products. For this reason the EU adopted the Directive 2003/96/EC of October 2003 restructuring the Community framework for the taxation of energy products and electricity. It entered into force in January 2004 with transitional periods in several areas. The Directive widens the scope of the EU's minimum rate system for energy products, previously limited to mineral oils, to all energy products including coal, natural gas and electricity. Moreover, its aim is to increase the incentive to use energy more efficiently as well as to allow EU Member States to offer companies tax incentives in return for specific undertakings to reduce emissions.

The initial results of the opening of the electricity market show: a radical transformation of the entire economic and political landscape of the electricity sector as well as a significant reduction in domestic and industrial electricity prices (on average approximately 6% since 1996, but as much as 20% in some Member States).

It is believed that without adequate safeguards, the move towards market liberalisation may have a damaging impact on the environment. With the advent of the liberalised market, privatisation of the energy industries and increased competition, energy companies are increasingly looking for short-term gains and to increase their market share, often at the expense of the environment.

Competition in the energy sector, which is likely to be dominated by western companies, will lead to lower fuel prices, but in return will reduce the incentives for investments in energy efficiency measures. The present market encourages energy supply companies to sell as much fuel as possible in order to increase profits. Cost-effective rational planning mechanisms, such as Demand Side Management are needed in order to provide an incentive for energy supply and distribution companies to consider reducing demand on an equal basis to that of increasing supply. Alarmingly, some utilities are considering ceasing to meter customer energy consumption in order to reduce the number of staff and, therefore, increase profits. This again could lead to the withdrawal of incentives for consumers to conserve energy and would have severe consequences for the environment.

The main obstacles in arriving at a fully operational and competitive internal market relate to, amongst other things, issues of access to the network, access to storage, tarification issues, interoperability between systems and different degrees of market opening between Member States. For competition to function, network access must be non-discriminatory, transparent and fairly priced. Today, the United Kingdom, which introduced partial gas competition in the late 1980s and full competition in 1998, still has by far the most competitive gas market in Europe.

The single energy market will ensure that electricity and gas in the European Union are sold competitively and in the most efficient way possible, leading to reductions in costs. At the same time the public service aspect of the internal market has been significantly reinforced by new legislation, including a new obligation to provide universal service in electricity, and an obligation to protect vulnerable customers. Energy efficiency will equally be promoted within the framework of the internal market. To ensure that the whole European Union benefits from the internal market, more interconnection between some areas is needed. This will not only guarantee access to competitive suppliers throughout the Union but will also increase security of supply.

3.2.2 Energy Supply Security – The Green Paper

In order to define a coherent and responsible European policy, focusing on a diversification of energy sources and a co-ordinated policy of rationalisation of energy consumption the EU published in 2000, a Green Paper on the security of energy supply. Security of supply should not be considered as a question of reducing import dependency and boosting domestic production. Security of supply calls for a wide range of policy initiatives aimed at diversification of sources and technologies and improved international relations. The Green Paper emphasises that the European Union is extremely dependent on external fuel supplies and that security of energy supply is essential for a future sustainable development, especially, as the life of the North Sea oil and gas reserves is projected to be very short. The Green Paper concludes that the adoption of new measures to reduce energy demand is essential both in terms of reducing the import dependence and in order to limit greenhouse gas emissions.

Thanks to the EU and Russia energy dialogue, both countries have created the principle that, for the EU, energy dependence is only acceptable if Russia guarantees the security and safety of its infrastructure, regular supplies and the protection of investments. According to the forecasts the

European Union will be increasingly dependant on energy from Russia. Russia is today Europe's most important supplier of oil and gas and covers 20% of EU consumption.

With current tensions in the Middle East, supplies from Russia will be of vital importance for long term economic growth. As for gas, an EU scenario shows that up to 60% of EU gas consumption will be imported from Russia by 2030. Energy markets are already truly global, and this will be more so in coming years as Europe's domestic reserves of oil and gas dwindle, demand from developing countries increase and competition builds up for the resources available.

As well as building up EU relations with Russia and the Middle East, it will be important for the EU to develop its energy relations with other key suppliers, such as Algeria and Iran – the country with the world's second largest gas supplies – as well as transit countries, such as Turkey and the Ukraine. The EU future energy security will also depend on maintaining a close dialogue with other major energy consumers – of which the USA, China and Japan are the largest. The strengthening of the producer-consumer dialogue is important but the co-ordinated response by all the EU Member States needs to be ensured, within a framework of solidarity.

Both the former EU-15 and the 10 new EU Member States energy systems are projected to reach similar levels of import dependency in the long run (67.8% and 65.2% respectively in 2030). This is despite the much better current position of the new Member States, with an import dependency of 30% in 2000 compared to 49% in the EU-15. Faster growing energy needs in the new Member States, combined with a decline of indigenous solid fuels production, are the main reasons. The new EU Member States dependency in terms of gas (72%) is higher than that of EU-15 (41.7%). A similar but less pronounced trend can be observed in the case of oil (87.7%, 76.8% in 1998).

The new EU Member States have no significant oil and gas reserves, so enlargement does not lower the import ratio. Because of this the optimisation of the energy supply networks and a continued consumer – producer dialogue will remain crucial. Restructuring of the coal industry in the new EU Member States will be a long and difficult process, just as it has been in the EU-15; in the meantime, in those countries clean technologies for using solid fuels should be widely adopted.

In the context of security of supply, coal has a major strategic advantage, it is widely distributed, and there are known coal reserves in over 100 countries, most of which are politically stable. In contrast to oil and natural gas, there has been continuing price stability over the last two or three decades. This is because of the wide distribution in coal supplies, the existence of an indigenous supply in most coal-using countries, and the ease and low cost of transporting solid fuel by sea in bulk carriers, and by land on trains. Although recently there have been coal price increases due in some part to the scarcity of bulk carriers and increasing use. These increases could be transitory. However these aspects have implications for the worldwide development of sustainable fuel markets.

As stated in the European Commission's Green Paper "Towards a European strategy for the security of energy supply" (November 2000), if no measures are taken, in the next 20 to 30 years 70% of the Union's energy requirements, as opposed to the current 50%, will be covered by imported products. This dependence affects all sectors of the economy and enlargement will not alter these trends.

To secure its external supplies the Union is faced with difficult choices. New forms of partnership will be required with the producer countries (Russia, Algeria, the countries of the Caspian Basin, as well as OPEC countries) and transit countries (such as Ukraine). The Union has already established close partnerships with Russia, and it has found new suppliers through new networks.

The Union must also be able to secure and modernise the existing supply networks. It has to promote renewable energy resources and energy efficiency and find the best response to the sensitive question of the role of nuclear energy in the enlarged Union. In any case the EU will have to favour less polluting energy sources. Greater integration of the electricity and gas markets will be needed in order to make the system more efficient. The framework of a long-term European strategy for the security of energy supply is set out in the Green paper “Towards a European strategy for the security of energy supply”.

According to this strategy:

- It is necessary to continue the creation of an internal energy market, in particular for electricity and gas.
- The Union must rebalance its supply policy by clear action in favour of a demand policy. The margins for manoeuvre for any increase in Community supply are weak in view of its requirements, whereas the scope for action to address demand is more promising.
- The Green Paper calls for a real change in consumer behaviour. It highlights the value of taxation measures to steer demand towards better-controlled consumption, which is more respectful towards the environment. Taxation or financial levies are advocated with a view to penalising the harmful environmental impact of energy.
- The development of new and renewable energies (including bio fuels) is the key to change on the supply side. An objective is to double their share in the energy-supply mix from 6% to 12% and raise their part in electricity production from 14% to 22% by 2010.
- The future of nuclear energy to the security of supply is uncertain. Its contribution will depend on several factors: the Kyoto process, competitiveness, acceptance by the public, solving the waste problem and safety in the new Member States.

Imports of oil and gas are increasing, and a stronger mechanism needs to be provided to build up strategic stocks and to foresee new import routes.

For at least the next 20–30 years, European energy policy will primarily be driven by the energy policies arising from the EC Green Paper towards a European strategy for the security of energy supply and will be influenced to a large extent by the energy strategy of the Russian Federation for 2020.

Energy demand in the EU is forecast to see a steady increase over the coming decades. Extensive studies carried out by the Commission indicate a range of possible energy futures. The following is extracted from the Commission's Energy Policy White Paper:

Some of the key messages which emerged may have policy implications for the Community:

* Europe will significantly increase its dependence on imported energy,
* Gas will compete with oil as a leading component of the fuel mix,
* European consumers will become increasingly dependent on 'grid' supplied energy,
* There is considerable flexibility as to the final shape of the future fuel mix.

According to the White Paper, the weight given to climate change concerns, the effects of technology and the liberalisation of markets and the fact that some renewables are on the threshold of economic viability will be the major determining factors.

In the Community there will be a steady growth in energy demand, compared to some other regions, with annual gross inland consumption increasing at slightly less than 1%. The demand in the industrial sector will stabilise at present levels while the domestic sector shows a slight decline. Transport growth continues and therefore is expected to consume more energy in spite of gains in vehicle efficiency.

On the demand side, natural gas consumption will show the greatest volume increase. Demand will at least double, mainly for power generation. In fact, electricity generation by gas-fired plants could reach almost half of the EU’s total thermal capacity, most of it in combined-cycle plants. In contrast, coal and nuclear are expected to lose market share.

In market share terms, the prevailing trend in Europe is of growing penetration of electricity and gas. Heat from decentralised cogeneration plants and renewables, in particular biomass, biofuels and wind, could make significant gains, squeezing the share of oil, although oil will still continue to hold the largest overall market share at around 42%. Solid fuels will remain significant in the thermal electricity market and could retain a share in excess of one-third of that market by 2020. Electricity generation from renewable sources and waste is planned to increase.

Renewable energies are expected to increase substantially by 2020. Energy intensity will continue to improve as new investments, using more energy efficient technologies, are made and other methods of managing demand are advanced. On the supply side, energy efficiency improvements could be particularly significant in electricity generation, while improved exploration and production technology will continue to release 'new' recoverable oil and gas reserves.

Community energy production seems set to decline, perhaps by one fifth by 2020. Although its onset could be considerably delayed by technological progress, the combination of increasing energy demand and an eventual decline in indigenous production would result in a growing trend in dependence on third countries. Import dependency, currently close to half of gross consumption, could move towards three-quarters by 2020. Dependency on imported natural gas increases most as a consequence of the rapid increase in demand. A significant share of the Community's gas will come from Norway. Dependency on coal imports could also increase as a result of declining domestic production. The Community is already heavily dependent on imported oil.

The EU energy policies, after the enlargement, will have to take account of increased dependency on Russia, important nuclear safety problems, the cost of improving energy efficiency, environment problems, security of supply, and social and regional consequences of necessary restructuring.

3.2.3 Environmental protection

The specific objectives of EU energy policy in the area of environmental protection are to reduce the environmental impact of the production and use of energy, to promote energy saving and energy efficiency, and to increase the use of cleaner energy and its share of total energy production. The vast majority of CO_2 emissions generated by man are attributed to the energy and transport sector. Transport and electricity/steam productions are each responsible roughly for a third of CO_2 emissions. Despite the progress made over the last ten years, the environment is one of the areas where the new EU Member States still have to catch up with EU-15 standards. Emissions are on average higher per capita than in the EU-15 and the energy sector often uses outdated technology and relies on poorer quality fuel.

Projections indicate that an increase of energy efficiency of 1% per year, two-thirds of the available savings potential could be achieved by 2010 – resulting in avoided CO_2 emissions of almost 200 Mt/year or around 40% of the EU Kyoto commitment.

The EU is responsible for 14% of world CO_2 emissions. At the Kyoto Conference in 1997 the EU undertook to reduce its greenhouse gas emissions by 8% between 2003 and 2012, compared with the figures of 1990. The current trend is an increase of 5%. The EU would emit an additional 300 Mt of CO_2 (approximately 10%) annually, if the Union did not use nuclear power to generate electricity. In order to achieve the Kyoto targets, the EC has had to take many measures and implement many regulations. On one side it has had to increase energy efficiency by encouraging the use of new technologies, and on the other side, it has had to introduce many emission limits in order to be ably to benefit from the Kyoto mechanisms. Below, follows a short description of the measures taken aiming at increasing energy efficiency and reducing emissions.

3.2.3.1 Measures aiming at increasing energy efficiency

A key component of the EU's policy for energy efficiency and energy savings and for contributing to the reduction in CO_2 emissions aiming at improving security of energy supply is the Directive 2004/8/EC of February 2004 (amending Directive 92/42/EEC) on the promotion of cogeneration based on a useful heat demand in the internal energy market. It provides for a regulatory framework for the promotion and development of high efficiency cogeneration of thermal heat and electrical and/or mechanical power based on useful heat demand and primary energy savings in the internal energy market.

The European Commission (EC) introduced a legislative framework for limiting energy consumption in the building sector, representing 40% of the energy consumed in the European Union by adopting the Directive 2002/91/EC on the energy performance of buildings. If implemented in all the EU countries, the Directive could help to save about 22% of this energy consumption.

The EC has also issued a proposal for a Framework Directive on eco-design requirements of energy-using products. Apart from the user's behaviour, there are two complementary ways of reducing the energy consumed by products: labelling to raise awareness of consumers on the real energy use in order to influence their buying decisions (such as labelling schemes for domestic appliances), and energy efficiency requirements imposed to products from the early stage on the design phase. It is estimated that over 80% of all product-related environmental impacts are determined during the design phase of a product. Against this background, eco-design aims to improve the environmental performance of products throughout the life-cycle by systematic integration of environmental aspects at the very early stage in the product design. The Commission has, therefore, proposed a Framework Directive on establishing a framework of setting eco-design requirements (such as energy efficiency requirements) for all energy using products in the residential, tertiary and industrial sectors.

In addition to the above, the EC has issued a proposal for a Directive on Energy End Use Efficiency and Energy Services. The Directive aims to enhance the cost-effective and efficient end-use of energy by providing the necessary targets, mechanisms, incentives and institutional, financial and legal frameworks to remove existing market barriers and imperfections for the efficient end-use of energy; and developing a market for energy services and for the delivery of energy efficiency programmes and other energy efficiency measures to end users.

3.2.3.2 Measures aiming at reducing emissions

In order to gradually reduce the annual emissions of sulphur dioxide and oxides of nitrogen from existing plants and to lay down emission limit values for sulphur dioxide, nitrogen oxides and dust in the case of new plants the EC has adopted strict regulations covering the control of emissions from power generation plants, as set out in the Large Combustion Plant Directive (2001/80/EC - LCPD) on the limitation of emissions of certain pollutants into the air from large combustion plants, which was adopted following the LCPD directive from 1988, following the 1985 Helsinki Protocol on SO_2 reductions and the 1988 Sofia Protocol on NOx.

The Directive encourages the combined generation of heat and power and sets specific emission limit values for the use of biomass as fuel. Furthermore, the scope now includes gas turbines in order to regulate NOx emissions as their use in electricity generation is growing. It should be noted that the proposed values are maximum values and that EU Member States may adopt stricter values if they wish so.

The new emissions limits will come into force in 2008, and will fully apply to both new and existing plants from 2016 onwards. By way of concession, existing plants may be exempt from obligations concerning new emissions standards if the operators declare not to operate the plant for more than 20,000 operational hours between 1 January 2008 and 31 December 2015. This, however, places a strict limit on the lifetime of the plant after the onset date of 2008.

The directive applies to all combustion plants with a thermal output greater than 50 MW, irrespective of the type of fuel used. These plants include power stations, petroleum refineries, steelworks, and other industrial processes running on solid, liquid, or gaseous fuel. Depending on the age of the plant, different regulations apply.

Plants, licensed after the onset date of the new Directive, will have to comply with the emission limit values for SO_2, NOx and dust fixed in part B of the Annexes III to VII of the draft Directive, setting values which are twice as strict as the current ones.

Plants licensed after 1 July 1987, the onset date of the old Directive, and before the date of entry into force of the new Directive, will have to comply with the emission limit values fixed in part A of the Annexes III to VII of the draft Directive. These are the values contained in Directive 88/609/EEC as amended by Directive 94/66/EC.

For plants licensed before 1 July 1987, so-called "existing" plants prior to the old Directive, which were previously excluded from the scope of the Directive, EU Member States may choose between two alternatives. By 1 January 2008 at the latest, they shall either: take the appropriate measures to ensure that all licences for the operation of existing plants comply with the requirements set for the plants licensed between 1 July 1987 and the date of entry into force of the new Directive; or define and implement an emission reduction plan on a national level. Existing pre-1987 plants may be exempted from compliance with emission limit values.

In order to achieve integrated prevention and control of pollution arising from defined activities and to tighten emission limits for new plants according to the Best Available Techniques the EC adopted the Directive 96/61/EC concerning integrated pollution, prevention and control called the IPPC Directive (amended by Directive 2003/35/EC and by Directive 2003/87/EC as well as by the Regulation (EC) No 1882/2003). The Directive attempts to strike a balance between the need to take into account local environmental conditions in issuing a permit and the need to ensure the emission standards throughout Europe. The emphasis of the Directive is on harmonising the procedures for regulating industrial emissions rather than harmonising emission limits overall. It requires that existing plants need to be upgraded to new plant standards by 2007, using the best available techniques and taking into account a cost-benefit analysis. Thus existing large combustion plants will be required to be re-permitted in line with IPPC standards. The Directive does, however, allow national pollution control authorities to take into account cost-benefit analysis when deciding whether to upgrade old plants.

In 2000 the EU took further steps to set up emission limit values for acid gases by implementing the Directive (2000/76/EC) on the incineration of waste covering the incineration of hazardous (formerly Directive 94/67/EC) and non-hazardous (89/369/EEC and 89/429/EEC) waste. The Directive prevents or – where it is not practicable - reduces as far as possible negative effects on the environment caused by the incineration and co-incineration of waste. In particular, it reduces pollution caused by emissions into the air, soil, surface water and groundwater. This will be achieved through stringent operational conditions and technical requirements and by setting up emission limit values for waste incineration and co-incineration plants within the Community.

Although the volume of waste incineration is forecasted to increase across the EU in the near future, the Directive will lead to significant reductions in emissions of several key pollutants. Considerable reductions will be achieved for acid gases such as nitrogen oxides (NOx), sulphur dioxide (SO_2) and hydrogen chloride (HCl) as well as for heavy metals. In addition, the Directive targets the incineration of non-hazardous waste, which has been identified as the largest source of emissions of dioxins and furans into the atmosphere.

Moreover, the EU took measures to promote the production of energy from renewable sources by adopting the Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the electricity market. It establishes a framework to increase the share of green electricity from 14% to 22% of gross electricity consumption by 2010 in compliance with the commitments made by the EU under the 1997 Kyoto Protocol on reducing greenhouse gas emissions.

The EC has issued a proposal for a Regulation on Fluorinated Gases. If adopted, the proposed Regulation would introduce a general obligation to take all measures that are technically and economically feasible to minimise emissions of fluorinated greenhouse gases. Specifically, it would introduce measures on the containment, use and recovery of certain fluorinated greenhouse gases, restrictions on the placing on the market of some applications containing these gases, and measures on the reporting of data on these gases. This proposal is now being considered by the EU Member States and the European Parliament. The European Parliament is expected to finalise its initial considerations of the proposal in mid - 2004. This means it is unlikely that the text will be finalised before late 2004 or early 2005.

In order to regulate the future greenhouse gas emissions trading scheme in the EU, the EU adopted a Directive 2003/87/EC of October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community which amends the Council Directive 96/61/EC. In order to minimise the economic costs of its Kyoto[7] commitments on combating climate change, the European Union is setting up an EU-wide market for carbon dioxide emissions of companies. Under this trading scheme, around 10,000 EU companies will be able (from 1 January 2005 onwards) to buy and sell permits to emit carbon dioxide. The directive allows companies who are doing better at reducing their emissions than their nationally set targets to sell their credits to

[7] see Annex

others (who are not reaching their objectives). The EU hopes that this system will stimulate innovation and create incentives for companies to reduce these emissions.

3.3 Energy policy in LAC

In view of the region's diversity, only the major issues on the agenda of the region as a whole are covered below.

In recent years the region's agenda has been focused on peace processes, democratisation and human rights, but now it is directed more towards international issues that affect the region (WTO, environment, new technologies etc).

With respect to other regional groups, the region is seeking political and economic relations balanced between its two principal partners, the United States and the European Union, in particular within the framework of strengthened economic integration. This priority is very much on the agenda, because the project to create an inter-American free trade area will have a decisive impact on trade with the rest of the world, and in particular Europe. A part of this trade is affecting the energy sector as it concerns gas, oil products and electricity exports to the US and coal exports to the EU.

A more detailed country-by-country analysis of the 26 OLADE countries' energy policies is presented in Annex 1.

Medium-term challenges for the countries of the region

Latin American energy systems remain inefficient. For example, for 4% of growth in GDP (in Brazil), the growth in energy demand is about 6%. As a comparison, for an equivalent growth in GDP, OECD countries see a 2% growth in energy demand. These data are alarming in view of the contribution of CO_2 to climate change. Another concern is the upward trend of the Latin-American energy system in terms of energy intensity (consumption/GDP), unlike all the developed countries. Latin America's share of final world consumption of oil is regularly increasing, which in the long term could create tension on the international market. Moreover, the slightest drought (Chile), or natural risks (Honduras, Nicaragua) or just a continuation of recent trends (Brazil) leads to crisis situations or shortages while still parts of the population (poorest sections of peripheral urban areas and isolated rural areas) have no access to energy.

The countries of the region have to face the medium term challenges and must respond to several priorities also influencing the energy sector:

- diversifying export production and supply and inclusion of a greater share of added value in export products;
- continuing regional integration, participation in international trade and compliance with WTO rules; stepping up trade with other regions of the world;
- encouraging external investment by setting up a sure, stable and transparent regulatory framework for companies; opening up strategic economic sectors to the outside;
- developing transport and transmission infrastructure, including the interconnection of intraregional networks

- a more effective energy management policy, aiming at competitiveness, guaranteed supplies and environmental protection;

Sustainable management of energy is a key element of economic and social development and must take account of the environmental dimension (climate change, implementation of the Kyoto Protocol). In view of the poor performances of Latin American energy systems the relevant administrations should be provided with expertise in the form of aid for pooling experiences and knowledge.

OLADE has aggregated the key issues on “sustainable energy management” into a program “Integration and Sustainable Development” that comprises the following objectives:

- To contribute to mitigate contaminating emissions from energy production and use based on the European experience, while not neglecting the growing demands of development in Latin America, and prioritising attention to the least protected sectors of the population.
- To support the creation of an appropriate environment for regional energy trade through the harmonization of laws and the identification and preliminary analysis of energy integration projects in order to better utilize the natural resources of the region and reduce the environmental impact of energy activities.
- To satisfy the crosscutting information requirements of the Member Countries of OLADE, the Permanent Secretariat and the program as a whole, in a timely and properly updated manner.
- To train the human resources of the region’s energy sector for the new challenges inherent in the liberalization of the sector and the integration of regional energy markets.

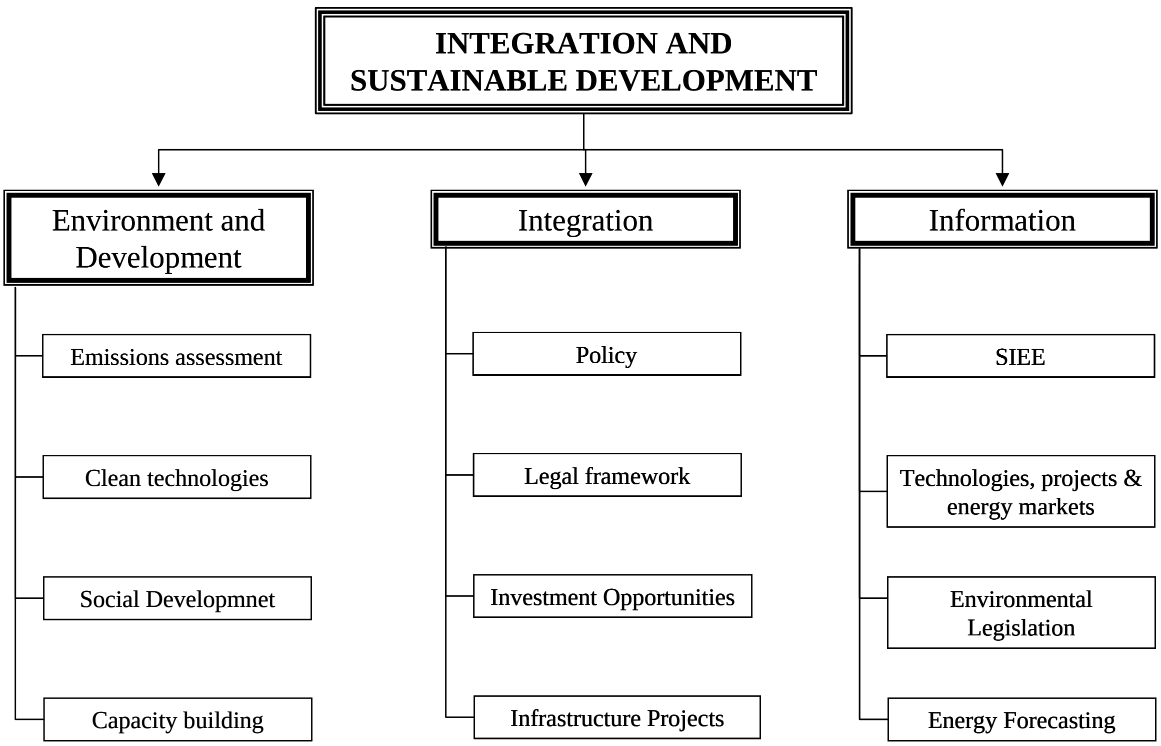


Figure: Composition of the program “Integration and Sustainable Development” (source: OLADE)

To achieve the proposed objectives, the program includes three subprograms:

- Environment and Development,
- Energy Integration, and
- Energy Information.

The three subprograms again include 19 projects with an overall budget of 19.6 million Euros. The European Commission contributes 9.9 million Euros and OLADE and its member countries contribute 9.7 million Euros.

The structure of the proposed Program, its three subprograms, and the areas they involve, are shown in the above chart. Each of the areas has 1 to 5 projects.

In the shown structure, SIEE does not imply additional resources. It is only shown because it provides information that is required by other projects.

Capacity building is also not a separate project, but an integral part of all the other projects and as such a component of each under the specific themes that are to receive attention.

3.3.1 Liberalization of the energy market

In the area of liberalizing energy markets, several countries have taken important steps to create or strengthen public regulatory and control agencies, and to encourage the participation of private companies, especially in electrical energy production, distribution, and marketing. For different reasons some countries have failed to complete the processes, some are retaking public control of certain activities, and others are incorporating second-generation reforms based on market experience in order to ensure the proper functioning of power markets to attract the investments for the expansion of the sector required.

Most Latin American and the Caribbean countries have partially segmented the sectors of power industry in order to ensure proper competition in the power generation sector, adequate availability, free access to transmission systems, and comparative competition in the electricity distribution and marketing sector. It is expected that increased interconnections between countries will bring about the consolidation of regional markets with optimised dispatching systems.

The figure below is prepared to rank the countries of the region according to the current diverse structures of the sector; the vertical axis contains the sector's ownership options, and the horizontal axis contains the sector's operational options; the classifications are explained below.

<u>Ownership Options</u>

a. Exclusive state ownership

The vertical axis begins with the original position of most of the countries prior to reforms, which was exclusive state ownership; all electrical system assets were owned by the state.

b. Mixed ownership

Moving away from the origin, there is a second option where private investors are shareholders of companies with additional participation of the state among the shareholders. There are also a few wholly state-owned companies, but they participate only partially in the sector.

c. Private Property

Finally, the option furthest from the origin refers to countries where the electrical system is predominantly under private ownership. In this case there are two options. The first involves "vertical" segmentation with an obligatory separation between generation, transmission and distribution activities; the second case includes a possibility for "vertical" integration, i.e. generation, transmission and distribution activities may remain in one hand.

Operating options

d. Central control

Traditionally, the entire chain of power generation and distribution was considered a natural monopoly. So it was logical that a single entity should own and operate the electrical service for an area, either owned by the state or by private companies. For years, the power sub-sector was considered monopolistic and a single company had a concession.

The majority of the countries of the region provided electrical service through a single state-owned company.

e. Single buyer

This principle has been applied to the region for several years and has allowed private entities to participate through a limited opening. This has especially been the case for generation, and was part of a process in some cases and a complete step in others.

f. Integrated and autonomous

This type of coordination involves a different distribution of the roles between the State and the company(s) that operate(s) in the sub-sector. The latter perform their activities according to their own initiative, planning and execution. The State has to approve the pertinent decisions on investments, rates, etc. It carries out regulatory functions either on its own behalf or through an agency that represents society (public commission), because it is a public service.

This system does not imply a vertical or horizontal breakdown. Integrated organization has been the dominant method used in the power sub-sectors of industrialized countries such as USA and Germany. A multitude of companies from the private, public or mixed sector participate in these sub-sectors. However, effective competition among them does not exist, because they often have exclusivity under a concession contract for an area of supply, or companies divide a sector among themselves by area or type of customer.

g. Open market

Natural monopolies are only maintained for main electrical power transportation and distribution activities, where its disputability is considered necessary. In sufficiently large systems that permit and ensure competitive behaviour, several participants can compete in the generating and marketing sectors.

OWNERSHIP OPTIONS

		(d) Central Control	(e) Single Buyer	(f) Integrated Autonomous	(g) Open Market
(c) Private Owner-ship	Vertical Segmentation with Incompatibility of Functions				Argentina (***) Bolivia(**) Guatemala(**) Panama(**)
	Vertical Integration Permitted			Barbados	Chile(**) El Salvador(**) Peru(**) Dominican Republic
(b) Mixed Ownership			Cuba Jamaica Ecuador Mexico Trinidad & Tobago Honduras	Costa Rica Grenada Guyana Uruguay Venezuela	(*) Colombia(**) Brazil Nicaragua
(a) Exclusive State Ownership			Suriname	Haiti Paraguay	

OPERATING OPTIONS

(*) With or without a strict vertical breakdown (incompatibility of functions);

(**) With weak horizontal partition;

(***) With a strong horizontal partition

Figure: Current state of power market liberalisation in LAC (source: OLADE)

Resistance to Privatisation

Apart from the dynamics of the response to crisis in Argentina, and the approach of the government in Brazil, there has been significant resistance to electricity privatisation in other Latin American countries.

In Ecuador, government attempts to privatise electricity assets have repeatedly encountered organised resistance including unions, provincial and local governments, indigenous organizations and others. In 2002, these campaigns forced the abandonment of proposals to sell electricity distributors, after Ecuador's Congress passed a resolution rejecting the privatisation, and a Constitutional Court ruling that the sales were unconstitutional. A further attempt at privatisation was abandoned in February 2004 when there was not a single tender for any of the companies. The utility Emelec - which was in limbo after the former owner, businessman Fernando Aspiazu, was charged in 2000 for irregularities in the administration of his bank Progreso - is being taken into public control by the city of Guayaquil, rather than being sold.

In Peru, the privatisation of generating companies, which began in 1995, has faced powerful opposition during the second step when the government tried to complete the privatisation of the smaller distribution companies. In June 2002 there were riots in Arequipa after two electric power plants (Egasa and Egesur) were sold to Tractebel. The government was forced to suspend the sale, and Tractebel backed out of the deal. However, the main utilities have been privatised during the first step.

In Colombia, there has also been resistance, notably in defence of the well-established municipal utilities. The campaign to prevent the privatisation of Emcali, the utility in Cali, has been led by the union SINTRAEMCALI and won worldwide support. (These campaigns have persisted despite the continued attacks on Colombian trade unionists - two trade unionists from SINTRAEMCALI, were critically injured in a letter bomb attack as recently as 7th June 2004).

In Mexico, successive attempts to privatise the electricity system have been defeated by strong campaigns led by the trade unions, resulting in court rulings and parliamentary decisions which have prevented the president from implementing privatisation plans.

3.3.2 Environmental protection

Environmental policy development in the countries of the region over the past years has been particularly intense. However, the energy and environmental policies have not received all the joint treatment that would have been desirable, as their levels of development have been dissimilar.

The implementation of the energy sector reforms was an opportunity to integrate environmental regulations and concentrate responsibilities in one or two institutions by country. Progress in environmental policies was seen since the “formal” integration of environmental protection as a fundamental ingredient of overall wellbeing.

As a consequence of this higher rank for environmental issues, being even included in the Constitution of some countries, environmental policy-making has taken a large leap forward. The issue of public participation in developing, implementing and supervising environmental standards is perhaps where most regulatory activity is seen in the countries of the region, especially with regard to energy development and attention to ethnic minorities. The progress should be highlighted that has been made in terms of participation in the process of environmental impact assessment and regarding rulings legitimating the filing of administrative or judicial action in defense of the environment and its components.

However, if an attempt were made to group the countries of Latin America and the Caribbean into different sub-regions, the formats, orientations and instruments of preference for executing a sustainable energy development strategy would vary in accordance to the outstanding priorities and characteristics of each sub-region, and even within these, differences among countries could be significant.

Another of the new trends seen in the region's environmental policies is that of attending to species conservation in situ. Here too, a certain reactivation of regulatory activities is seen.

Likewise, over the past years, the countries of the region have embarked upon an important process of reforming the administrative apparatus, and significant progress has been made in terms of effectiveness and efficiency in the management of environmental matters on a governmental level. In general, there is a growing trend towards the creation of high-level central environmental authorities with the power to coordinate and integrate environmental management, protection and resources throughout the different sectors. Particularly worth highlighting are the efforts that countries have been making, with varying levels of success, to simplify and rationalize licensing procedures and involve different sectors in decisions that could affect the environment. The orientation of said efforts is fairly even and, together with the regional trade agreements in effect, fans the hope for legislative harmonization.

With regard to Environmental Impact Studies (EIS), significant progress has been made in regulating public participation, access to information, inclusion of minorities, and access to administrative or judicial review. However, it is still necessary to integrate this set of elements into a coordinated procedure, whose terms will be tailored to each particular circumstance. In this regard, it is important to point out that while the first generation of EIS legislation in the region made no reference to establishing objective guidelines or criteria to orient the assessment of environmental impact studies, there are already examples – albeit embryonic in some cases – of enormous progress towards ensuring the effectiveness of the tool and the transparency of the process.

Progress in mechanisms for environmental policy administration and implementation go hand in hand with a renewed emphasis on economic growth, which translates as a marked tendency to flexibilize the legal requirements of environmental protection for development activities. In turn, the above comes along with a greater level of citizen activism seeking to reorient administrative activities towards environmental protection through administrative courts and tribunals, in order to balance development and environmental protection. The combination of new legal participatory tools and growing environmental awareness makes these country jurisdictions the depositories of a high level of experience in dealing with environmental issues in the legal field.

Improving the population's quality of life through equitable access to energy is also a topic that is at the head of policy programs throughout the region and has direct impact on the relationship between environmental protection and development. This concern tends to give way to legislative promotion of alternative energy development, particularly regarding energy access by rural sectors and those located in remote areas relative to existing supply networks. Also noteworthy is the new impetus given by the concept of energy efficiency as one of the best roads to a cleaner, more sustainable energy future. This trend is currently seen reflected in programs, policy papers, and a few isolated rulings that promote efficiency and demand management.

Recently, primarily as a response to the international financial community, several countries of the region have adopted policies that favour utilizing market mechanisms and economic instruments as tools for environmental protection and sustainable economic development. In the Andean countries, available instruments include charging for resource use, payments for polluting, special investment conditions, contract fulfilment guarantees, taxes, subsidies, and also, in the case of Bolivia, the possibility of establishing negotiable permit systems. The special investment conditions and contract fulfilment guarantees are the most used instrument in these countries, which may be due to the relative ease of managing these instruments.

3.3.3 Kyoto Protocol

The Region as a whole has participated actively in world environmental protection activities. This is evidenced by the fact that the 26 OLADE countries have signed the Framework Convention on Climate Change, 23 have signed the Kyoto Protocol (with the exception of Haiti, Suriname and Venezuela, according to current OLADE records) and in 20 countries the respective National Authorities for the Clean Development Mechanism are in operation (with the exception of Barbados, Guyana, Haiti, Dominican Republic, Suriname and Venezuela). The following table provides more detailed information on the countries' participation in these initiatives.

Country	Framework Convention on Climate Change			Kyoto Protocol		National Authority for CDM
	Signed	Ratified	Took Effect	Signed	Ratified	
Argentina	12/06/92	11/03/94	21/03/94	16/03/98	28/09/01	Argentine Office of the Clean Development Mechanism Secretariat of Environment and Sustainable Development
Barbados	12/06/92	23/03/94	21/06/94	--	07/08/00	----
Bolivia	10/06/92	03/10/94	01/01/95	09/07/98	30/11/99	National Program on Climate Change, Clean Development Office, Vice Minister of Natural Resources and Environment
Brazil	04/06/92	28/02/94	29/05/94	29/04/98	23/08/02	Interministerial Commission on Global Climate Change
Chile	13/06/92	22/12/94	22/03/95	17/06/98	26/08/02	National Commission on Environment (CONAMA)

Country	Framework Convention on Climate Change			Kyoto Protocol		National Authority for CDM
	Signed	Ratified	Took Effect	Signed	Ratified	
Colombia	13/06/92	22/03/95	20/06/95	--	30/11/01	Colombian Office on the Mitigation of Climate Change Ministry of Environment
Costa Rica	13/06/92	26/08/94	24/11/94	27/04/98	09/08/02	Costa Rican Office for Joint Implementation Ministry of Environment and Energy
Cuba	13/06/92	05/01/94	05/04/94	15/03/99	30/04/02	Ministry of Science, Technology and Environment (CITMA)
Ecuador	09/06/92	23/02/93	21/03/94	15/01/99	13/01/00	Climate Change Unit, National Committee on Climate, Ministry of Environment
El Salvador	13/06/92	04/12/95	03/03/96	08/06/98	30/11/98	Mitigation Component, National Program on Climate Change, Department of Environmental Management, Ministry of Environment and National Resources
Grenada	03/12/92	11/08/94	09/11/94	--	06/08/02	----
Guatemala	13/06/92	15/12/95	14/03/96	10/07/98	05/10/99	Guatemalan Office for Joint Implementation
Guyana	13/06/92	29/08/94	27/11/94	--	05/08/03	----
Haiti	13/06/92	25/09/96	24/12/96	--	--	----
Honduras	13/06/92	19/10/95	17/01/96	25/02/99	19/07/00	Secretariat of Natural Resources and Environment, Office of Joint Implementation and CDM of Honduras
Jamaica	12/06/92	06/01/95	06/04/95	--	28/06/99	Ministry of Land and

Country	Framework Convention on Climate Change			Kyoto Protocol		National Authority for CDM
	Signed	Ratified	Took Effect	Signed	Ratified	
						Environment
Mexico	13/06/92	11/03/93	21/03/94	09/06/98	07/09/00	Mexican Committee on Projects for Reducing Emissions and Sequestering Greenhouse Gases
Nicaragua	13/06/92	31/10/95	29/01/96	07/07/98	18/11/99	National Office of Clean Environment, Ministry of Environment and Natural Resources
Panama	18/03/93	23/05/95	21/08/95	08/06/98	05/03/99	National Environmental Authority
Paraguay	12/06/92	24/02/94	25/05/94	25/08/98	27/08/99	National Climate Change Program, Secretariat of Environment
Peru	12/06/92	07/06/93	21/03/94	13/11/98	12/09/02	National Council on Environment
Dominican Republic	12/06/92	07/10/98	05/01/99	--	12/02/02	----
Suriname	13/06/92	14/10/96	12/01/98	--	--	----
Trinidad & Tobago	11/06/92	24/06/94	22/09/94	07/01/99	28/01/99	Ministry of Public Utilities and the Environment
Uruguay	04/06/92	18/08/94	16/11/94	29/07/98	05/02/01	Climate Change Unit; National Department of Environment Ministry of Housing, Territorial Organization and Environment
Venezuela	12/06/92	28/12/94	28/03/95	--	--	----

Table: Status of the Ratification of the Framework Convention on Climate Change, the Kyoto Protocol and the establishment of National Authorities for CDM in Latin America and the Caribbean (source: OLADE)

3.3.3.1 Ecological benefits for LAC

Latin America and the Caribbean countries possess significant energy resources such as oil (10% of the world reserves), natural gas (4.4%), coal (1.6%), biomass and other renewable resources as well as a huge hydroelectric potential (22.7%). In the last decade, these countries have increased their energy consumption owing to their economic development and to the growth in their population. This has generated an increase in their greenhouse gas (GHG) emissions. In addition, about two-thirds of the carbon dioxide released from the region stems from the deforestation of 4-6 million hectares of forests that are eliminated annually by burning of the forest. Latin America and the Caribbean produce 8% of the world's GHG emissions. Mexico, Brazil, Argentina, Venezuela, Colombia and Chile rank among the largest emitters of carbon dioxide in Latin America. From an energy point of view, four countries (Mexico, Brazil, Argentina, and Venezuela) consume 73% of the energy and 79% of the electricity. Industry (34%) and transportation (31%) are the sectors that consume more energy in the region. Energy resources used in electricity generation come from renewable resources (70%), followed by thermal generation (14% oil derivatives, 11% natural gas, 3% coal and 2% nuclear). As a result, Latin American countries provide significant opportunities for CDM project investments.

3.3.3.2 Economic benefits for LAC

Countries in Latin America and the Caribbean possess excellent opportunities for investment and technology transfer in mitigation projects under the Clean Development Mechanism (CDM)[8]. This "flexibility mechanism" was established by the Kyoto Protocol with the objective that industrialized nations comply with their commitment of reducing greenhouse gases (GHG) at lower costs. At the same time, CDM provides to developing countries a new source of income through an innovative environmental service: the removal of infrared absorbing gases from the environment.

So far, several CDM project opportunities have been identified in Latin America and the Caribbean. These include areas such as energy supply; energy efficiency; energy management; renewable energy generation; renewable energy training; fuel switching; land-use change and forestry including carbon sinks; fugitive gas capture and in particular methane from landfills and coal mining; industrial process control; agriculture; and water, waste water and waste disposal. Brazil is by far the Latin American country with the largest portfolio of CDM projects. A variety of other Latin American countries have CDM projects in the pipeline including Costa Rica, Colombia, Argentina and Mexico.

[8] see Annex

4 Perspectives of the EU and LAC energy markets

Key findings:

- The European Union represents around 16% of the world energy market and is the largest net energy-importing region in the world in absolute terms.
- Installed EU power generation capacity is projected to increase by nearly 60% from 1999 to 2030 (incl. new member states).
- Over half of existing power plants are expected to be decommissioned until 2030. Most new capacity is expected to be gas-fired, particularly in combined-cycle gas turbine (CCGT) plants.
- EU25 will suffer a significant growth of energy import dependency from 47.1% in 2000 up to 67.5% in 2030, an increase of more than 20%.
- Coal consumption will become increasingly concentrated in power generation and specialised industrial uses, such as steel-making. The power sector will account for 80 % of primary coal use by 2030 compared to 76 % in 2000, and the industrial sector will take almost all of the rest.
- Despite the continuing contraction of the EU coal market, demand will be increasingly met with imports, as indigenous production declines even more rapidly.
- Natural gas consumption in EU has grown more in absolute terms than that of any other fuel over the past three decades, and this trend will continue to 2030. The share of gas in total primary energy demand will continue to rise from 23 % in 2002 to 32 % in 2030.
- Oil will remain Europe's largest energy source, with primary oil demand increasing by 0.5% per year from 2000 to 2030. Almost all demand will come from the transport sector.
- The LAC region has 10% of the world’s oil reserves, 4.3% of the world’s natural gas reserves, and 1.6% of the world’s coal reserves. Moreover, 22.7% of the world’s hydroelectric potential is found in the LAC region.
- In 2003 the energy demands of Latin America and the Caribbean constitute approximately 6.6% of the world energy market.
- The region has sufficient energy reserves for its consumption needs and for export to other regions of the world; based on actual consumption (basis: year 2003 and proven reserves) the total reserves of oil and gas, however, would serve the demand for no more than 30 years.
- Energy strategies of Latin America and the Caribbean are focused to increase the access of the population and industry to power.
- To achieve the projected high coverage of power access it is necessary to install rural electrification and the use of renewable energy in remote areas.
- Natural gas is the main fuel for power production and its role will even be strengthened in the future.

- The distribution and access to natural gas will be enforced by strengthening the pipeline network system in the region.
- Countries of the Southern Cone have indicated the intention to refurbish oil fired power stations to gas fired power stations.
- In the LAC region coal actually only plays a minor role as an energy source for power production; however, with the depletion of oil and natural gas reserves in about 30 years, coal may gain a more preferential position in the power sector.
- Hydropower represents a strong option for power generation in LAC and will play an important role in the energy mix of the region for the long term.

The context for European energy supply policies has been extended over the last 30 years as a result of political, environmental, economic and energy market developments, and now includes such aspects as enlargement, climate change and liberalisation of the markets. At the same time European energy supply policies face different forms of risk – physical, economic, and environmental. The EU is consuming more and more energy and importing more and more energy resources as its own resources diminish. Community production cannot cover the Union’s energy requirements. Without an active common energy strategy, the EU will not be able to meet its long-term economical strategic objectives and is becoming increasingly dependent on energy imports.

4.1 EU energy strategy until 2020

The European Union represents around 16% of the world energy market and is the largest net energy-importing region in the world in absolute terms, importing close to half its needs. Despite continuing economic integration, national energy profiles and trends among the EU member states remain very diverse. This diversity reflects varying stages of economic development and differences in policy priorities, economic structure, taxes, climate and local resources. Nuclear power, for example, is a source of primary energy in some countries, i.e. Belgium, Finland, France, Germany, the Netherlands, Spain, Sweden, Switzerland and the United Kingdom, but plays no role in the other states. The share of renewable energy in each country's energy mix also varies markedly, depending on the local availability of resources and government efforts to promote their use.

Indigenous production accounts for around 56% of the Union's natural gas consumption. The region produces half the coal it bums and 27% of its oil. Production of oil, most of it from the UK sector of the North Sea, has increased over the last decade or so but is now set to decrease. Gas production has also risen but is also like oil set to decrease in the future. Coal production has fallen by more than half since 1990. Subsidies to high-cost coal mines have been slashed in several countries, notably France, Germany, Spain and the United Kingdom.

Oil is the predominant energy source, although its share in primary energy use has declined since the 1970s. Coal use, in both relative and absolute terms, has fallen sharply and is now largely confined to power generation. The share of gas has risen steadily, from 8% in 1971 to 23% in 2000. Nuclear energy now accounts for about 15% of primary energy demand, having grown rapidly between the late 1970s and the early 1990s. In 1998, both capacity and output declined, albeit marginally, for the first time.

Economic growth in the EU15 fell from 3.4% in 2000 over 1.7% in 2001, 1.2% in 2002 to 1.1% in 2003 in line with the slowing global economy. The slump has been most severe in Germany and Italy, while the United Kingdom and France have continued to enjoy moderate growth. The initial weakness of the Euro after its launch in 1999, combined with higher oil prices, intensified inflationary pressures and reduced the European Central Bank's scope for cutting interest rates to stimulate economic activity.

Having in mind the energy situation in the European Union, the chapters below describe the projected development of the energy market in the European Union. The energy strategy of the former European Union consisting of 15 countries (EU Member States as of before 01.05.2004), referred to as EU15, is described on the basis of the projections of the International Energy Agency in the World Energy Outlook 2002, referred to as WEO-2002. These projections are amended by the forecast according to the Green Paper, as well as the newest projections of the publication “European energy and transport – Trends to 2030”, referred to as Trends to 2030. The “Trends to 2030” publication gives detailed projections on energy market development for the EU15 and EU25 (all EU Member States after 01.05.2004) as well as the ACC (new EU Member States since 01.05.2004) separately. These projections show how the future energy and CO_2 emissions may unfold with a continuation of current trends and policies. They are built on a modelling approach encompassing both energy demand and supply.

The reference year of the data from WEO-2002 and Trends to 2030 is the year 2000 which makes the data directly comparable. Additionally, the data are amended by the most actual data from the World Energy Outlook 2004 – referred to as WEO-2004 – which refers to the reference year 2002. Hence, the direct comparison of data is limited, however, trends can easily be recognised.

The projections of WEO-2002 are based on the assumptions that the EU economy will grow by 1.9% a year on average from 2000 to 2030. Growth will be the fastest in the period to 2010 (2.3%), based on a prompt recovery from the current economic slowdown. Growth will slow down to 2% per year from 2010 to 2020 and to 1.6% from 2020 to 2030. The differences in growth rates between countries are expected to shrink with the macroeconomic convergence intended to result from economic and monetary integration. The European population is assumed to decline slightly over the projection period. It follows from these assumptions that GDP per capita will be more than 80% higher by 2030. The European Union would remain the third-richest region in the world, in per capita terms behind the US and Canada and OECD Pacific.

Trends to 2030 project the EU energy demand and supply on the basis of the assumptions of economic activity, world energy prices and on the broad framework conditions for economic actors. Additionally, it is assumed, that energy prices correspond to those for EU15. Policy assumptions follow closely those for EU15 given that the acquis communautaire will be implemented in the ACC. Economic growth in EU25 will be somewhat higher than in EU15, because the ACC grow faster, from lower levels in the past. EU25 GDP is projected to grow 2.4% per year, slightly more than doubling in 2030. According to the Trends to 2030 (and contrary to the WEC), the EU25 population is assumed to grow slightly (whereas the EU15 population is assumed to grow and the ACC population to decline) over the projection period.

The projections of the WEO-2004 is based on the assumptions that global economic growth is assumed to average 3.2% per year over the period 2002-2030, slightly less than in the previous three decades. The rate will drop from 3.7% in 2002- 2010 to 2.7% in the last decade of the projection period, as developing countries’ economies mature and population growth slows.

Economic growth in the European Union remains sluggish in major countries, though the pace of recovery has picked up in some countries. Overall, EU's GDP grew by only 1.1% in 2003. Near-term economic prospects are nonetheless improving. Growth is expected to average over 2% in 2004 and above 2.6% in 2005. Over the period 2002- 20 10, growth is assumed to average 2.3%. It then slows to 2.1% from 2010 to 2020 and to 1.7% from 2020 to 2030. The differences in growth rates among countries are expected to shrink with the macroeconomic convergence that should result from economic and monetary integration. European population is assumed to remain broadly unchanged over the projection period, rising very gradually through to the mid-2010s and falling back very slowly thereafter. As a result, GDP per capita will be 75% higher by 2030 than in 2002.

The demand side of the EU25 energy system has undergone significant changes in terms of the fuel mix during the last decade as a result of shifts towards the use of more efficient energy forms. Energy developments in EU25 are in many respects similar to those in the current EU – especially as regards the key long-term challenges associated with the growth in CO_2 emissions, the penetration of renewables and rising energy import dependency.

4.1.1 Electricity

According to WEO-2004, new power plants with a total capacity of 766 GW are expected to be built in the EU25 over the period 2003-2030. This will yield a power generation capacity of around 1,443 GW by 2030. Installed generation capacity is projected by the WEO-2002 to increase from 573 GW in 1999 to 679 GW in 2010 and 901 GW in 2030, a growth of nearly 60%. Over half of existing plants are expected to be decommissioned over the projection period. Most new capacity is expected to be gas-fired, particularly in combined-cycle gas turbine (CCGT) plants. In 2030, 41% of capacity will be gas-fired, compared to 16% in 1999. Over the first half of the projection period, very few new coal plants are likely to be built and several existing ones will probably be decommissioned. As a result, the share of coal in generation will drop sharply. In the second half of the projection period, higher gas prices and improvements in coal technologies are expected make new coal-fired generation more competitive. According to Trends to 2030, electricity production increases 54% in the period 2000-2030. Power generation capacity is expected to reach 1,132 GW in 2030.

The WEO-2002 projects that the share of nuclear power will reduce to more than half on the assumption that few new plants are built and that many of the existing plants will be decommissioned. Installed nuclear capacity is projected to fall from 124 GW in 1999 to 76 GW in 2030. Fuel-cell capacity is projected to reach 30 GW in 2030. Non-hydro renewables-based electricity, mainly wind and biomass, will increase rapidly. Wind's share of generation will grow from 0.9% in 2000 to almost 5% in 2030. The share of biomass in total generation will also increase rapidly, from 1.8% to 5%. Most biomass, essentially wood, agricultural residues and municipal waste, will be used in co-generation plants, initially in boilers or gas turbines. Gasification technology will become more widespread towards the end of the outlook period. The main sources of uncertainty in EU electricity generation are future fuel price trends, national policies on nuclear power and renewables, technological developments and new environmental regulations.

The WEO-2002 expects the fuel mix to change markedly, with gas and electricity replacing coal and, to a lesser extent, oil products (mostly heavy fuel oil and heating oil). The share of coal in total primary energy use will continue to decline, from 15% in 2000 to 10% in 2030. The share of gas will increase, from 23% in 2000 to 28% in 2010 and 34% in 2030, by which time the use of gas will be almost as extensive as that of oil. The share of non-hydro renewable also rises steadily, overtaking nuclear just before 2030. Nuclear output is projected to fall away after 2010.

In Trends to 2030, the power station sector gradually shifts away from coal and nuclear, which each had a 32% share in 2000. By 2030 the nuclear share falls to 17% and that of coal to 27%. By 2030 gas will be the most important fuel input for electricity (accounting for 36% of power generation, from 16% in 2000).

EU25 primary energy demand has continued to edge higher since 2000. Demand dipped in 2002, largely because of mild winter weather, but rebounded by almost 2 % in 2003. According to WEO-2004, primary energy demand in the EU25 will grow at an average annual rate of 0.7 % from 1,690 Mtoe in 2002 to 1,848 Mtoe in 2010 and to 2,048 Mtoe in 2030. It is the lowest growth rate of any WEO regions. Total primary energy demand in EU is assumed, by the WEO-2002, to rise also by 0.7 % per year from 2000 to 2030 in the reference scenario, slower than the 1.2% rate of 1971-2000. The pace of demand growth will decelerate after 2010, mainly due to saturation effects. Total primary energy demand in EU25 (in this case the same as EU15) respectively ACC is assumed, by the Trends to 2030, to rise by 0.6 % respectively 0.8 % per year from 2000 to 2030.

Final energy demand, according to WEO-2004 will grow by 0.9 % per year, slightly higher than primary energy demand. Electricity will take a growing share of final energy use. The WEO-2002 projects that the EU final energy consumption will grow by 1.2 % per year between 2000 and 2010 and by 0.7 % between 2010 and 2030, compared with 2.9 % in 1971-2000. The transport sector will remain the fastest growing sector in final energy demand. It’s share in the total final consumption will increase from 30 % in 2000 to 33 % in 2030. Electricity use will expand most rapidly in the residential and services sectors, where it will increase by about 0.9 % a year. However in Trends to 2030, final energy demand in EU25 is projected to increase by 29.3 % (0.9 % a year) between 2000 and 2030 well above the projected primary energy needs (+19%) (0.6 % a year). This difference reflects the significant efficiency gains that power generation undergoes. Overall final energy demand growth is rather similar in the EU15 and the ACC (+28.5 % and +34 % respectively in 2000-2030). Thus, while demand growth in EU15 is projected to peak in the next decade and decelerates afterwards, energy demand in ACC is projected to exhibit even stronger growth between 2010 and 2020 and then to slow down in the long run. The main drivers for these different growth patterns include: issues related to the different economic evolution between EU15 and ACC; further reduction of inefficiencies in CEEC; and the likely faster development of saturation effects for a number of energy uses beyond 2010 in the EU15.

According to the Trends to 2030, electricity demand in EU25 is projected to exhibit the highest growth over the projection period (+ 1.6 % per year in 2000-2030). The share of electricity by 2030 will account for less than a quarter of final energy demand. The projected electricity demand growth can be considered as modest, given that, historically, electricity use grew at rates above GDP. Saturation effects, technological progress and the exploitation of energy savings options are the main reasons limiting electricity demand growth.

The EU high import dependence will increase further as demand rises. EU net imports of oil and gas will jump from 566 Mtoe in 2000 (31 % of primary consumption) to 1,116 Mtoe by 2030 (62 %). This is in line with the projections in the European Commission's Green Paper on energy security. By the end of the projection period, the European Union will account for 20 % of global net inter-regional trade in oil and 34 % of that in gas.

According to Trends 2030, the combined effect of increasing primary energy demand for fossil fuels and declining primary production results in a significant growth of import dependency for the EU25 energy system from 47.1 % in 2000 up to 67.5 % in 2030, an increase of more than 20 %. In 2000, import dependency was 30 % in the ACC but close to 50 % in EU15. In 2030, import dependency in ACC is expected to reach 65 %, while that in EU15 reaches 68 %

Despite ongoing improvements in the energy efficiency of household, commercial appliances and equipment and better building insulation, residential and services energy demand, according to WEO-2002, will rise steadily over the next three decades. Driven by growing business activity and rising living standards, which will stimulate demand for larger homes, more office space and new appliances will be required. Much of the growth in energy demand will be in the form of electricity.

Energy use in industry is projected by the WEO-2002 to grow slowly in the coming three decades. By 2030, gas and electricity will account for 63 % of industry's total energy consumption. According to the WEO-2004 energy intensity will continue to fall in line with past trends, at an average annual rate of 1.3 % from 2002 to 2030. Autonomous improvements in energy efficiency (improvements unrelated to new government policies) will drive energy intensity down. So will the continuing structural shift of the EU economy to less energy-intensive activities.

4.1.2 Coal

According to WEO-2004 coal will continue to play a key role in the world energy mix, with demand projected to grow at an average annual rate of 1.4 % to 2030. At the same time the EU25 primary coal demand is projected to decline at an average annual rate of 0.2 % from 767 Mt in 2002 to 716 Mt in 2030. The WEO-2002 expects that primary coal demand in the EU is to go on falling, at an average of 0.6 % per year over the projection period from 2000 to 2030. Coal consumption will become increasingly concentrated in power generation and specialised industrial uses, such as steel-making. The power sector will account for 80 % of primary coal use by 2030 compared to 76 % in 2000, and the industrial sector will take almost all of the rest. Trends to 2030 projects that primary coal demand, after a strong decline to 2010, will regain some market share in the EU25 energy system beyond 2015 as a result of the increasing competitiveness of imported coal and also nuclear plant decommissioning. By 2030, primary energy demand for coal is projected to come close to that observed in 2000. Coal is also projected to exhibit a modest decline with market share of primary coal demand reaching 15 % in 2030 compared to 18.3 % in 2000.

Final demand for coal in specialised industrial uses, such as steel-making declined by more than 50 % between 1990 and 2000. Trends to 2030, projects final coal demand in the EU25 to decline over the period up to 2030 and then it will become an obsolete energy form in end use. By 2030 coal will account for 2.1 % of final energy needs on the demand side, compared to 5.3 % in 2000 and 11,9 % in 1990.

Coal imports, according to the WEO-2004, will grow. Mainly due to further closures of unprofitable mines in those countries which still have them: the Czech Republic, Germany, Poland, Spain and the United Kingdom. As regards Trends to 2030, coal, through import dependency under baseline assumptions, is also projected to grow significantly. It remains at lower levels compared to oil and gas, reaching by 2030 65.7 % up from 30.1 % in 2000.

Despite the continuing contraction of the EU coal market, demand will be increasingly met with imports, as indigenous production declines even more rapidly. The amount of EU hard coal production receiving government support has fallen over the past decade, both in absolute and percentage terms. Subsidised production is now concentrated in Germany and Spain. Germany is expected to reduce subsidies and subsidised output by reducing its number of hard coal mines from 10 mines in 2000 down to 5 mines in 2012. The United Kingdom reinstated subsidies to its coal industry in April 2000, but they only ran until July 2002. Spain expects to reduce production by a further 20% by 2005. Recent EU rules allow coal subsidies to continue, in some cases, on energy security grounds. The EU adopted a regulation in July 2001 that establishes rules for the continuation of state aid after the expiration of the European Coal and Steel Community Treaty in 2002. The regulation will remain in force until 2010.

4.1.3 Natural Gas

Natural gas resources in EU countries, a little more than 2 % of the world's total, are expensive to exploit. Output from the North Sea, a mature producing region, will dwindle over the coming decades. Natural gas (growing by 2.4 % per year – a rate four times higher than average) and electricity made significant increases to satisfy demand during the last decade, substituting for solids and liquid fuels. EU gas production amounted to around 240 bcm in 2003. The total EU25 gas production is projected in the WEO-2004, to decline down to 225 bcm in 2010 and 147 bcm in 2030. The share of gas in power production is projected to increase from 15 % in 2002 to over 35 % in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period. Trends to 2030 predict natural gas production will drop by nearly 40 % to 2030, but this will happen largely in EU15.

Natural gas consumption has grown more in absolute terms than that of any other fuel over the past three decades, and this trend will continue to 2030.

According to WEO-2004, primary gas demand in the EU25 will grow at an average annual rate of 1.8 % from 2002 to 2030 – the most rapid growth rate of any fuel other than non-hydro renewables. The share of gas in total primary energy demand will continue to rise from 23 % in 2002 to 32 % in 2030. According to the WEO-2002, primary gas use will grow by 2.9 % per year from 2000 to 2010 and by 1.6 % from 2010 to 2030. Demand will increase in all end-use sectors, but most dramatically so in power generation. According to the Trends to 2030, primary gas demand will grow by 3.1 % per year from 2000 to 2010 and by 1.6 % from 2010 to 2020 and by 0.5 % from 2020 to 2030. Generally from 2000 until 2030 it will grow by 1.7 %. Natural gas spurred by its rapid penetration both on the demand and the supply sides, accounts by 2030 for 32 % of primary energy needs (+ 9.2 percentage points compared to 2000 levels).

Trends to 2030 predict that final natural gas demand growth in EU25 will decelerate in the long run due to limitations in infrastructure but also through technological factors. The share of final gas demand will rise to 24.5 %, on the final gas demand side by 2030.

The WEO-2004 projects an increase in gas demand which, therefore, will have to be met by increased imports. Rising demand and stagnating production will result in a surge in net imports, from 233 bcm in 2002 to 342 bcm in 2010 and 639 bcm in 2030. The bulk of this gas will go to meet new power-sector needs. The share of imports of total gas demand in EU25 will rise from 49 % in 2002 to over 81 % by the end of the projection period. The growing share of EU gas imports will be shipped as LNG. Incremental imports are expected to come from the Union's three main current suppliers, Russia, Norway and Algeria. Imports of LNG from Nigeria and Trinidad and Tobago are set to rise. New sources will probably include Caspian region, Libya Egypt and Qatar. Venezuela may also emerge in the longer term as a supplier of LNG, while spot shipments of LNG from other Middle East, Latin American and African producers may also increase if a global short-term market in LNG develops.

According to the Trends to 2030 the EU25 external dependence in terms of primary natural gas demand will increase sharply, reaching 81.4 % by 2030 compared to 49.5 % in 2000.

There is undoubtedly enough gas in EU countries to meet EU needs. But the unit costs of getting that gas to market will probably rise as more remote and costly sources are tapped. Piped gas from North Africa and the Nadym-Pur-Taz region in Russia are the lowest cost options, but supplies from these sources are projected by the WEO-2002 not to be sufficient to meet projected demand after 2010. Pipeline projects based on fields in the Yamal Peninsula and the Shtokmanovskoye field in the Barents Sea in Russia are among the most expensive longer-term options. So are pipelines from the Middle East and the Caspian region. LNG, traded both under long-term contracts and on spot markets, could play a much more important role in supplying the European gas market if supply costs continue to fall. LNG would become especially important if there turns out to be less Russian gas available than expected. This could occur if investment in new fields is insufficient to compensate for the decline in production from existing fields. In any event, the distances over which LNG imports from new sources need to be shipped may well drive costs and prices up.

4.1.4 Oil

EU oil production (including LNG) averaged about 3.2 mb/d in 2001, almost all of it coming from the UK (77 %) and Danish (11 %) sectors of the North Sea. Output grew steadily in the 1990s, peaking in 1999. The WEO-2004 projects that the EU25 oil production will fall from 3.2 mb/d in 2002 to 2.2 mb/d in 2010 and to 1 mb/d in 2030. Production from the North Sea, the main source of indigenous supply, has already peaked. Its decline – led by production from the United Kingdom – is expected to accelerate over the coming years. In the WEO-2002 projection production is expected to decline gradually over the coming years, although new discoveries and the development of small marginal fields could arrest the decline, if only temporarily. EU oil production is projected to fall to 2.3 mb/d in 2010 and 1.1 mb/d in 2030. Trends to 2030 depicts that, oil production will fall by nearly 50% over the period 2000-2030, but this will happen nearly entirely in EU15, as the ACC produce little oil. The decline is driven by the increasing competitiveness of imported coal and natural gas.

According to the WEO-2004 EU25 primary oil demand is projected to grow by 0.5 % per year on average, from 13.6 mb/d in 2002 to 15.6 mb/d in 2030. The WEO-2002 projects that oil will remain Europe's largest energy source, with primary oil demand increasing by 0.4 % per year from 2000 to 2030. Oil's weight in primary energy supply will fall slightly, from 41 % in 2000 to 37 % in 2030. Almost all the increase in demand will come from the transport sector. Aviation fuel demand will grow fastest of all. Demand for diesel will increase faster than for gasoline, because of continuing growth in road freight and a continuing trend towards using diesel in passenger cars. No tax changes are assumed and hence most countries will carry on taxing diesel more lightly than gasoline. The Trends to 2030 projects that primary oil demand exhibits a moderate growth of 0.3 % p.a. over the projection period from 2000 to 2030, through at a rate well below average. Oil is also projected to exhibit a modest decline with their market share, on the primary oil demand side reaching 34.8 % in 2030 compared to 38.4 % in 2000.

Trends to 2030 shows final oil demand is the main energy carrier in the EU25 energy demand sectors over the projection period, but growing at rates well below average, constantly losing market share. By 2030 some 80 % of final oil demand is projected to arise from the transport sector, compared to 70 % in 2000. According to the WEO-2004 in the transport sector, where oil use is increasingly concentrated, the pace of demand growth will slow. Saturation effects and major improvements in the fuel efficiency of new cars and trucks will largely cancel out the effect of rising incomes on personal mobility and freight. Alternative fuels, including natural gas, will also displace oil-based fuels. According to Trends to 2030, oil is projected to lose market share on the final oil demand side, dropping just below 40 % in 2030 from 43.2 % in 2000.

Imports already meet 76 % of EU primary oil demand, and this share will grow to 94 % by 2030, according to the WEO-2004. All the net oil-importing regions will become even more dependent on imports over the projection period (2002-2030). Increased trade, especially from the Middle East, will strengthen the mutual dependence among exporting and importing countries. The EU net oil import requirements are assumed by the WEO-2002 to rise sharply as indigenous production dwindles and demand rises. Oil from OPEC countries will meet a large part of these additional needs. OPEC currently accounts for 42 % of the Union's oil imports. The Trends to 2030 project that by 2030 more than 88 % of primary energy needs for oil, excluding requirements for marine bunkers, will be satisfied by imports compared to 76.5 % in 2000. Oil imports are projected to continue consisting mainly of crude oil, as net imports of oil products will remain marginal.

4.2 LAC energy strategy until 2020

The region has 10% of the world’s oil reserves, 4.3% of the world’s natural gas reserves, and 1.6% of the world’s coal reserves (see also chapter 5.1). Moreover, 22.7% of the world’s hydroelectric potential is found in the LAC region.

In 2003 the energy demands of Latin America and the Caribbean constitute approximately 6.6% of the world energy market.

The region has sufficient energy reserves for its consumption needs and for export to other regions of the world, since its total reserves would serve the demand for many years.

In the LAC region coal only plays a minor role as an energy source (see Chapter 5.1.1) for power production. From the power production point of view only the oil and natural gas sector are of strategic importance.

4.2.1 Power market development on natural gas

Future development of natural gas use and trade in Latin America over the next decade will be greatly influenced by Brazil, to be considered as South America’s leading economy. An ambitious plan is currently prepared to increase the country’s gas fuelled electricity generation in the next years, to reduce the strong dependence on hydro-electric generation which is by far the main source of power. It seems clearly admitted that hydro power in Brazil will no more be able to meet energy needs during low-rainfall years and that gas based power generation has to be urgently developed.

In most Latin American countries the same trend will be followed with Brazil and Chile leading the way, with - as a consequence - a major increase of natural gas in the energy matrix. As in many other regions in the world, the initial development of gas-fuelled power generation will be followed by increased gas consumption for industrial, commercial and residential use.

Bolivia will clearly remain the main supplier of gas to Brazil, considering the pipeline already in operation and recent major gas discoveries. The most recent estimation of proven plus probable reserves amount today to 911 10^9 m^3.

Argentina is characterized by a relatively mature domestic market, and will supply Brazil and Uruguay through existing and new pipelines, but also continue to export gas to Chile. However, there is an uncertainty on the real reserve potential of Argentina that has proven reserves of 766 10^9 m^3 .

Peru is well endowed with 274 10^9 m^3 non associated gas reserve in Camisea field. Even thinking that its development has been subject to long delays, by the end of 2004 the gas pipeline arrived at Lima and is in operation.

Venezuela in the north is currently under pressure for increasing its gas activity, with ambitious plans prepared by the State company PDV for opening the sector to private investment. This means that Venezuela, endowed with the seventh-largest gas reserves in the world (5,235 10^9 m^3 of proven plus probable reserves including associated gas), will play a major role and considerably extend its activity in the region in the next decade.

A large growth potential

The necessity of market integration is particularly strong, if the level of expected growth in the region is taken into consideration as well as the ineluctable opening of markets. The current share of natural gas in the energy mix of most countries is still low and provides a significant growth potential. Each country has however a distinct profile and different growth potential in various areas.

In Brazil and Chile gas is a small component in the energy mix, a substantial growth can be expected in all areas. In Argentina and Venezuela domestic markets are mature and gas consumption makes up respectively 47% and 50% of the primary energy mix.

As a whole for the total 26 OLADE's countries natural gas consumption accounted in 2003 for 19% of the region's primary energy mix. Starting from this point natural gas consumption could be expected to more than double in the region from 192 10^9 m^3/day in 2000 to about 422 10^9 m^3/day in 2010.

The same process will be experienced in all countries: initial growth is in power generation, then industrial applications and lastly in the residential sector. Another positive point for gas development is that energy demand in most countries is expected to continue to outrun economic growth with an elasticity in the range 1.0 to 1.1. This is a rule in emerging economies that energy consumption growth has to be greater than GDP growth. Therefore economic growth in most countries of Latin America will require a substantial increase in energy needs and consequently provide a large potential for natural gas market development.

Main candidate projects for natural gas interconnection

Total proven reserves in the area amount to 7,532 10^9 m^3, including a large share of associated gas in Venezuela and Brazil. Considering proven and probable reserves but excluding associated gas this figure drops to 3,141 10^9 m^3. In the present situation Argentina (766 10^9 m^3 of proven reserves) and Bolivia (811 10^9 m^3 of proven reserves) are the exporting countries and importing countries include Brazil, Chile, Uruguay and soon Paraguay. Gas demand in the South America excluding Venezuela and Trinidad & Tobago over the period 2000 to 2015 represents a total of 1,653 10^9 m^3 (low scenario) while expected production in the same area is equivalent to 1,449 10^9 m^3. It means that in the medium / long term demand for gas, driven by large markets such as Brazil and Argentina, will reach such a level that import will be required from Venezuela, Trinidad and Tobago, and possibly Peru. The future optimum configuration of gas flows in the area involving both pipeline links and LNG connections will depend on expectations for additional reserves, transportation costs and structure of markets.

Three gas interconnections are currently under operation:

- From Bolivia to Argentina: this is the oldest connection from Santa Cruz (Bolivia) to Yacuiba (Argentina) with a 500 km pipeline of 24" and a capacity of 8 10^6 m^3/day.
- From Argentina to Chile: the "Gasodusto Bandurria" from San Sebastian (Tierra de Fuego in Argentina) to the methanol plant Planta Cullen (Chile), with 83 km of 14" line and a capacity of 2 10^6 m^3/day has started in 1996. In 1997 the "Gasoducto Gasandes" (463 km, 24", capacity maximum 20 10^6 m^3/day) has allowed to bring to Santiago gas from Neuquen (Argentina). More recently in May 1999 the "Atacama" pipeline (941 km, 20", capacity maximum 8.5 10^6 m^3/day) has started to supply the northern area of Chile (Mejillones) from Salta province in Argentina. Two other pipelines have just started operation : the "Gasoducto Norandino" (1180 km , 20"-16"-12", 7.1 10^6 m^3/day) from Pichanal to Mejillones and Coloso, and the "Gas Pacifico" pipeline (638 km, 24"-20"-12"-10", 9.7 10^6 m^3/day) from Neuquen to Concepcion.
- From Bolivia to Brazil: the "Bolivia-Brazil" pipeline is the most impressive and successful project in the region (3150km, 32", capacity maximum 30 10^6 m^3/day). It takes gas from Santa Cruz in Bolivia and supplies Sao Paulo and southern States of Brazil down to Porto Alegre, and has started operation in May 1999.

Some pipeline connections are still under construction:

- From Argentina to Brazil: the "Gasoducto Uruguaiana" ships gas from Entre Rios to a power plant in Uruguaiana (440km, 24", capacity 12 10^6 m^3/day) and then is projected to reach Porto Alegre (615 km, 20").
- From Argentina to Uruguay: "Gasoducto Cruz del Sur" (208 km, 18 /24", capacity maximum 6.6 10^6 m^3/day) from Buenos Aires to Montevideo).

Some candidate projects for new interconnections can already be identified:

- From Argentina to Brazil: the "Gasoducto del Mercosur" would link gas fields from north Argentina (Salta) to Sao Paulo through Asuncion in Paraguay (3100 km, 36" to 24", capacity 25 10^6 m^3/day). The "Gasoducto Austral" would link gas fields from South Argentina (Cuenca Austral) to Montevideo (Uruguay) and then Porto Alegre (Brazil) (3700 km, 36" /30", capacity 31 10^6 m^3/day).
- From Bolivia to Chile: a pipeline from Villamontes to Tocopilla and Mejillones in northern Chile (850 km, 20" /16", capacity 6 10^6 m^3/day)
- From Bolivia to Paraguay: the "Trans-Chaco" pipel from Vuelta Grande in Bolivia to Asuncion in Paraguay (846 km, 22", capacity 6.9 10^6 m^3/day)

- From Peru to Bolivia: from Camisea field to Carraco in Bolivia (900 km, 36", 40 10^6 m^3/day). This line would in the long term allow to bring gas from Camisea to the largest market of Brazil.
- From Peru to Brazil: from Camisea to Sao Paulo through Porto Belho, (3550km, 32", capacity 30 10^6 m^3/day).

Other projects can be considered, in particular involving LNG import from Venezuela and Trinidad and Tobago. It is clear that some of above projects will be to a certain extent in competition.

Figure: Gas pipeline network system in LAC and its prospects of development (source: Repsol)

An analysis performed by OLADE, ARPEL and Beicip Franlab in 2001 highlights the following prospects on the natural gas market in the LAC region:

- Serious gas supply problems in the Southern Cone will arise around 2010. The two main surplus countries in the area –Argentina and Bolivia- cannot meet the demand to follow growing needs in deficit countries Chile and Brazil. LNG from Venezuela is then required to supply North East Brazil in 2010, and in 2015 LNG supply is extended to South East Brazil, Argentina and Chile.
- If production in Argentina follows a conservative profile (i.e. low production) difficulties are enhanced, and LNG supply from Venezuela or Africa would be also required after 2010 to meet demand for both Chile and Argentina.
- If gas production in Argentina is on the high side, it displaces the most part of LNG needs until 2015 leaving only a terminal to supply North East Brazil.
- Whatever scenario is considered there is in the short term a competition between Argentina and Bolivia to meet the promising Brazilian market. In the medium term this competition is extended to Venezuela as a third potential supplier.
- This competition is reflected in the four routes to supply the South / South East Brazilian market (excluding the existing Bolivia –Brazil pipeline):
  - The old Mercosur route, open to both Argentina and Bolivian gas,
  - The pipeline project from Uruguaiana to Porto Alegre, open only to gas from Argentina,
  - The pipeline project (Pan American Energy) from Montevideo to Porto Alegre, open only to gas from Argentina,
  - A direct line from Bolivia to Porto Alegre through Paraguay, open preferably to gas from Bolivia.
- The Uruguaiana route seems to be the most advanced solution, which gives an advantage to gas from Argentina in the short term. However, on the basis of distance and flow optimization the model was giving the preference to a link along the Mercosur route, with gas shipped from both Bolivia and Argentina and possibility of swaps.
- According to first estimations, gas from Camisea would not be competitive to displace LNG from Venezuela to North East Brazil. However, it could displace LNG supplies to Argentina and Chile.
- An alternate scenario involving a lower gas demand (20% reduction in 2010 and 25% reduction in 2015) allows to eliminate LNG imports until 2015. It would correspond to a situation of "suppressed demand" where LNG price would be too high to compete with local gas and competing fuels.

<u>Barriers to gas development and integration</u>

Gas integration in the region could, however, face some serious constraints linked with the resistance to the liberalization process in leading countries and to the increased participation of private actors in various parts of the gas sector from exploration to distribution. In Argentina where transmission and distribution markets were fully opened to private capital, a serious debate has been seen between Energas, the Regulator, transmission companies, distributors, traders, and consumers. Companies believe that changes imposed by the Regulator will affect their profitability and hinder future investments.

Similar problems appear in Venezuela where the current Government gives to market analysts the impression that it does not favour enough the liberalization process. However, it remains clear that 4,147 10^9 m^3 of proven reserves (even including associated gas) is a strong incentive to attract industry partners. A push for gas development is part of the Government's plan to diversify the economy from oil dependence.

Brazil also raises some questions as to the real signs the Government is giving for opening its gas markets. Some industry analysts believe that the strong role of State and Federal authorities, coupled with the duties of the National Petroleum Agency (ANPE), and the power of Petrobras will complicate and delay the full implementation of the market reform. This could slow down the full development of natural gas penetration in the energy market.

Increased gas market integration will be based not only on new inter-regional pipeline links but also LNG supplies from Venezuela and possibly Trinidad and Tobago. Cristobal Colon LNG project in Venezuela has recently revived on a smaller scale including PDV and partners such as Shell, Exxon-Mobil and Mitsubishi. In Trinidad a project is under way to triple the current LNG production to 9 million tons by adding two additional trains, and export mainly to USA and Spain.

4.2.2 Refurbishment of oil to gas fired power stations

Countries of the Southern Cone have indicated to refurbish oil fired power stations to gas fired power stations in order to free export potentials of oil and oil products.

4.2.3 Enhancement of hydropower utilisation

Although current tendencies in the region clearly show that thermal power generation will continue to replace hydroelectric power generation, hydropower still is a strong option for the long term future. The region has a share of almost 23 % at the worldwide hydropower potential. In 2003 only 22% of the total hydroelectric potential in the LAC region was being utilized. The estimation for 2020 is an increase up to 25%.

On the short term, due to the high investment, the long construction periods and the long distant power transmission (associated with high losses) from the remote hydropower plants to the populated areas, hydropower cannot compete with e.g. highly efficient gas fired power plants. Nevertheless, on the long term (> 30 years) oil and gas reserves in the region will start to deplete and hydropower is envisaged to obtain a larger share in the energy mix of the region.

Actually OLADE feels that a major commitment of international technical and financial assistance for the development of hydroelectric power in the region could free up exportable resources of fossil fuels. This could be the region's contribution to world energy security, and help reduce greenhouse gas production by the LAC electrical sector.

4.2.4 Electricity

Regarding electrical power consumption in the region, it is expected that there will be a greater degree of industrialization in the region that will improve the standard of living of the population. More efficient use will be made of energy and electrical losses in the transmission system will be reduced. Electricity demand is estimated to be about 1.9 million GWh in 2020. Of this figure 24%

will be commercial consumption (including transportation and other services), 50% industrial, and 26% residential.

In 2005 OLADE will publish the next forecast on energy demand and production for the LAC region indicating the development prospects of the LAC energy market until 2025.

5 The LAC power market

Key findings:

- The installed electrical generation capacity of the LAC region totals approximately 253 GW in 2003.
- In 2003 52% of the installed power is hydroelectric, 45% is thermoelectric, 2% is nuclear, and 1% utilizes sources such as geothermal, wind, solar and biomass.
- Power production in the 26 OLADE countries was 1,021 TWh in 2003, an increase of 42.5 TWh (4.3%) compared to 2002.
- The power market is growing by 4-5% p.a., i.e. approximately 12 GW p.a.
- Many LAC countries report high level of transmission and distribution power losses which is in average about 19% for the region.
- Power consumption in Latin America and the Caribbean was 820.7 TWh in 2003, an increase of 34.2 TWh (4.3%) compared to 2002.
- Coal met only 5% of primary energy demand in Latin America in 2003, of which 65% was used in Brazil. Latin America has proven recoverable coal reserves of 16 billion tons.
- About 42% of coal production is dedicated for export to the EU and United States.
- LAC‘s proven natural gas reserves amounted to 7.5 10^{12} m^3 in 2003, 5% of the world’s total.
- Venezuela holds 54% of the proven reserves, followed by Bolivia (10%), Argentina (10%), Mexico (8%) and Trinidad and Tobago (7%).
- LAC’s natural gas production in 2003 was 197 10^9 m^3. Production is expected to expand significantly over the next three decades, reaching 516 10^9 m^3 in 2030.
- The region‘s proven oil reserves stood at 114.5 billion barrels at the end of 2003, i.e. 10% of the world’s total.
- LAC’s production of crude oil and LNG averaged 9.4 mb/d in 2003 and is expected to increase to almost 12 mb/d by 2030. Production is dominated at present by Venezuela, Mexico and Brazil.
- Compared to the world oil refining capacities LAC has a share of almost 9%.
- South European and US companies dominate the LAC power sector.
- The involvement of Southern European companies such as Endesa, Iberdrola, Union Fenosa, EdP, EdF, Tractebel, etc. in the LAC region may serve of providing management in the LAC, technology transfer and exporting of EU CFT hardware to LAC markets.
- Electricity tariffs in many countries allow the utilities to make profit. However, political uncertainties and legal framework instabilities in the region cause financial risk.
- The LAC region is split into 2 operating power networks with different frequencies: the southern countries operate on 50 Hz whereas the northern countries operate on 60 Hz.
- LAC countries are moving towards integration of the power networks, including the Central Americans countries, through the implementation of the SIEPAC (Sistema de Interconexión

Eléctrica de los Países de América Central – System of power interconnection in the Central American countries) project under the Framework Agreement of the Central American Electrical Market and the creation of the Regional Electricity Market.

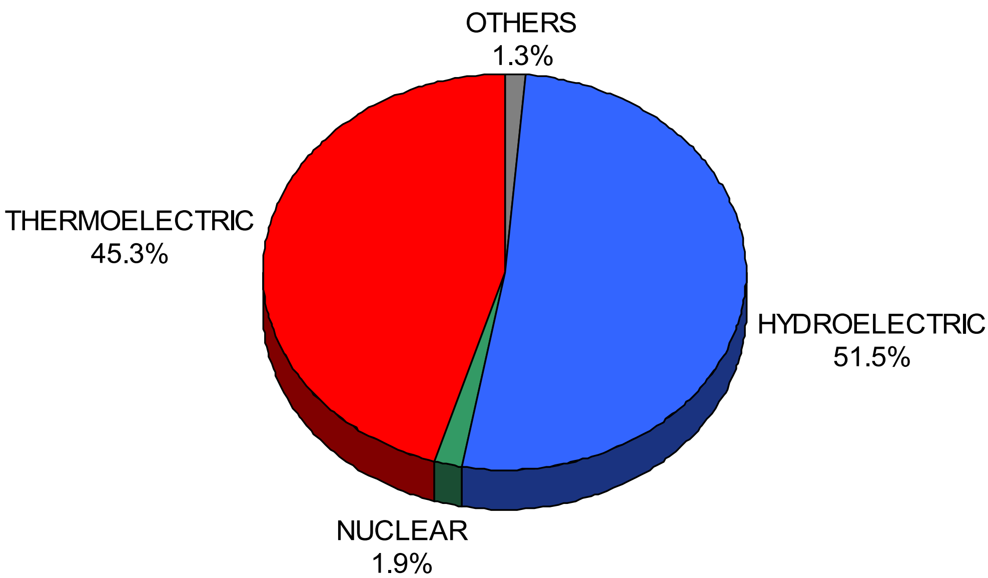
- The main types of power plants technologies applied are gas fired turbines and gas or oil fired boilers with steam turbines; however, power generation by combined cycle gas turbine technology will obtain more and more shares in the region.
- In order to meet the growth of power demand annually roughly 12 GW of new power plants have to be installed.
- The evaluation of the power plant technologies in LAC has been derived from the Energy-Economic Information System (SIEE) operated by OLADE.
- In the LAC 73% of the power plants have nominal outputs less than 50 MW, 23% are in the range of 50 to 400 MW and 4% are in the range of between 400 to 1000 MW.
- In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam or gas turbines.
- Gas turbines account for 27%, steam turbines for 56%, gas combined cycle plants contribute 7% and diesel engines 6% of the power generation. The balance of 4% is made up by geothermal and nuclear power plants.
- 85% of the power generation is based on oil and natural gas. Coal actually plays no major role in the LAC power sector although large reserves are present in the region.
- A replacement potential of actually around 9 GW can be identified for the running decade.

Power Generation Capacities

The installed electrical generation capacity of the region in 2003 totals approximately 253 GW (see following table and figure), an increase of 7% compared to 2002. Of this amount, 233 GW are facilities for public service and the rest are self-generators. Brazil, Mexico, and Argentina are the countries with the greatest installed power capacities for producing electricity. In 2003 52% of the installed power was hydroelectric, 45% thermoelectric, 2% nuclear, and 1% stemmed from sources such as geothermal, wind, solar and biomass.

COUNTRY	HYDROPOWER POTENTIAL	INSTALLED CAPACITY BY TYPE OF PLANT [MW]				
		HYDRO	THERMO.	NUCLEAR	OTHERS*	TOTAL
ARGENTINA	44.500,00	9.782,73	19.772,00	1.018,00	26,33	**30.599,06**
BARBADOS	0,00	0,00	209,50	0,00	0,00	**209,50**
BOLIVIA	190.000,00	479,20	872,86	0,00	1,20	**1.353,26**
BRAZIL	260.000,00	67.791,80	16.705,80	2.007,00	0,00	**86.504,60**
COLOMBIA	93.085,00	8.893,00	4.690,15	0,00	70,00	**13.653,49**
COSTA RICA	6.220,00	1.295,63	395.,57	0,00	247,76	**1.938,96**
CUBA	650,00	57,40	3.901,30	0,00	0,40	**3959,10**
CHILE	26.046,00	4.279,14	6.456,94	0,00	2,00	**10.738,08**
ECUADOR	23.467,00	1.733,58	1.410,00	0,00	397,80	**3.541,38**
EL SALVADOR	2.165,20	442,00	514,60	0,00	262,40	**1.219,00**
GRENADA	0,00	0,00	32,00	0,00	0,00	**32,00**
GUATEMALA	10.890,00	627,30	1.352,80	0,00	29,00	**2.009,10**
GUYANA	7.600,00	0,50	307,50	0,00	0,00	**308,00**
HAITI	173,00	63,00	181,00	0,00	0,00	**244,00**
HONDURAS	5.000,00	465,70	578,30	0,00	0,00	**1.044,00**
JAMAICA	24,00	23,60	667,10	0,00	120,00	**810,70**
MEXICO	51.387,00	9.649,94	37.560,74	1.365,00	962,55	**49.538,23**
NICARAGUA	1.700,00	104,40	510,66	0,00	77,50	**692,56**
PANAMA	3.698,80	833,00	491,00	0,00	231,20	**1.555,20**
PARAGUAY	12.516,00	7.410,00	6,10	0,00	0,00	**7.416,10**
PERU	61.832,40	3.032,31	2.937,05	0,00	0,70	**5.970,06**
DOMINICAN REP.	2.010,00	542,10	4.184,20	0,00	804,00	**5.530,30**
SURINAME	2.420,00	189,00	200,00	0,00	0,00	**389,00**
TRINIDAD & TOB.	0,00	0,00	1.416,00	0,00	0,00	**1.416,00**
URUGUAY	1.815,00	1.538,00	633,00	0,00	0,00	**2.171,00**
VENEZUELA	46.000,00	12.491,00	8.086,00	0,00	0,00	**20.577,00**
REGIONAL	**853.199,40**	**131.724,67**	**114.072,17**	**4.390,00**	**3.232,84**	**253.419,68**

*OTHERS: GEOTHERMAL+SOLAR+WIND



Total: 253.4 GW

Figure: Latin American and Caribbean electricity production capacities by type of plant, 2003 (source: OLADE)

Many energy resources in the region remain to be developed for power production, especially hydroelectric resources. The countries with the greatest potential in this area are Brazil, Colombia, Peru, Mexico and Venezuela. Compared to the world hydropower potentials LAC is a major player (see figure below), however, its capacities are only used to 22% of the maximum potential.

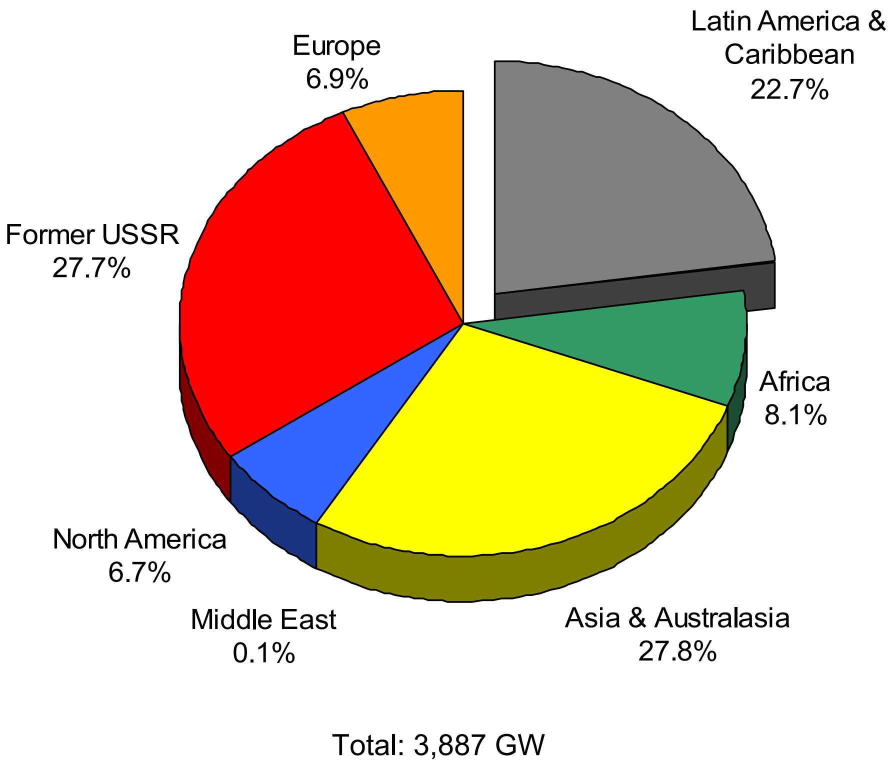


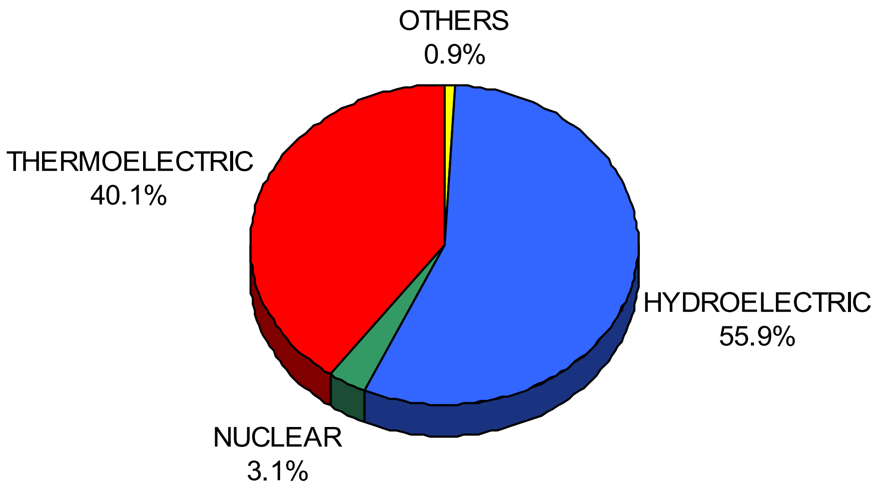
Figure: World Hydropower Potential (source: OLADE)

Power production

Power production in the 26 OLADE countries was 1,021 TWh in 2003, an increase of 42.5 TWh (4.3%) compared to 2002, a confirmation that the regional electricity market is growing and offers good opportunities for investment.

COUNTRY	HYDRO	THERMO.	NUCLEAR	OTHERS*	TOTAL
ARGENTINA	33.777,00	50.635,00	7.566,00	75,00	**92.053,00**
BARBADOS	0,00	870,90	0,00	0,00	**870,90**
BOLIVIA	2.306,72	1.962,76	0,00	0,00	**4.269,48**
BRAZIL	290.006,42	60.758,74	14.080,40	0,00	**364.845,56**
COLOMBIA	35.952,42	11.729,84	0,00	0,00	**47.682,26**
COSTA RICA	6.021,86	157,15	0,00	1.385,88	**7.564,89**
CUBA	79,00	15.831,20	0,00	0,00	**15.909,20**
CHILE	24.176,51	20.878,49	0,00	0,00	**45.055,00**
ECUADOR	7.152,52	4.348,75	0,00	0,00	**11.501,27**
EL SALVADOR	1.704,62	1.930,23	0,00	1.128,86	**4.763,7**
GRENADA	0,00	153,60	0,00	0,00	**153,60**
GUATEMALA	2.176,59	4.189,49	0,00	195,02	**6.561,10**
GUYANA	0,00	819,74	0,00	0,00	**819,74**
HAITI	197,00	315,00	0,00	0,00	**512,00**
HONDURAS	1.745,00	2.784,91	0,00	0,00	**4.529,91**
JAMAICA	353,49	6.792,52	0,00	0,00	**7.146,01**
MEXICO	19.753,00	167.534,99	10.502,00	5.945,00	**203.734,99**
NICARAGUA	297,39	2021,91	0,00	270,70	**2.590,00**
PANAMA	2.871,01	2.799,63	0,00	0,00	**5.670,64**
PARAGUAY	51.761,11	0,42	0,00	0,00	**51.761,53**
PERU	18.537,50	4.388,83	0,00	0,00	**22.926,33**
DOMINICAN REP.	1.562,18	11.926,72	0,00	0,00	**13.488,90**
SURINAME	959,71	535,84	0,00	0,00	**1.495,55**
TRINIDAD & TOB.	0,00	6.436,60	0,00	0,00	**6.436,60**
URUGUAY	8.529,07	48,84	0,00	0,00	**8.577,91**
VENEZUELA	60.177,33	29.639,58	0,00	0,00	**89.816,91**
REGIONAL TOTAL	**570.096,47**	**409.491,65**	**32.148,40**	**9.000,46**	**1.020.736,98**

*OTHERS: GEOTHERMAL+SOLAR+WIND



Total: 1,021 TWh

Figure: Latin American and Caribbean Electricity Generation by Type of Plant, 2003 (in GWh)
(source: OLADE)

Approximately 56% of the electricity produced in the 26 member countries of OLADE comes from hydropower; 40% from fossil fuels, 3% from nuclear power plants and 1% from geothermal, wind and photovoltaic sources. The electrical power produced by self-generators was 10% of the total production.

One of the critical problems in many countries of the region is the high level of electrical power losses, and as a group it stands at 19%. This is high compared with industrialized countries. There are countries in the region that are below 10% and others that are above 30 %.

Power Consumption

Power consumption in Latin America and the Caribbean was 820.7 TWh in 2003 (see table overleaf), an increase of 34.2 TWh (4.3%) compared to 2002.

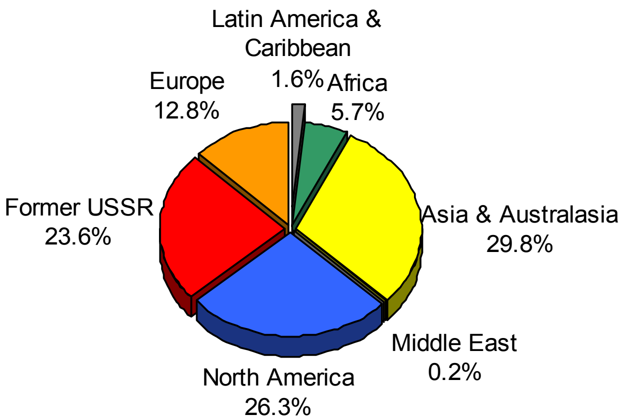
Per capita electricity consumption in 2003 was 1,529 kWh, an increase of 42 kWh compared to 1,487 kWh/person in 2002. Residential consumption per capita increased to 403 kWh, demonstrating a positive trend in the economic development of households.

Electricity's share of the total power demand of the industrial, residential, and commercial sectors was 22.2 %, 22.9 % and 66.3 %, respectively. There was a small percentage increase recorded for the business and services sector.

5.1 Fuels demand and supply [9]

5.1.1 Coal

Coal met only 5% of primary energy demand in Latin America in 2003, of which 65% was used in Brazil. Latin America has proven recoverable coal reserves of 16 billion tons, of which 6.6 billion tons are in Colombia, 5.3 billion tons in Brazil, 1.8 billion tons in Mexico and 1.3 billion tons in Venezuela.



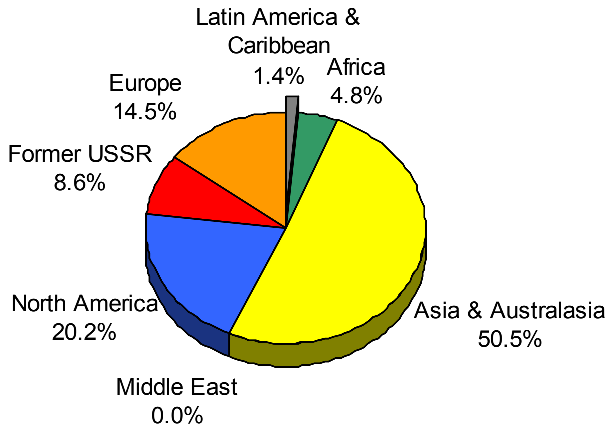


Figure: World reserves of coal (left) and world production of coal (right), 2003 (source: OLADE)

[9] For consistency of data this chapter only refers to data from the SIEE – Energy-Economic Information System of Olade (www.olade.org). Data from other sources (e.g. BP Statistical Review of World Energy 2004) have not been considered.

COUNTRY	POPULATION	GROSS DOMESTIG PRODUCT	FINAL ENERGY CONSUMPTION	PER CAPITA GDP (3)	PER CAPITA FINAL CONSUMPTION	ENERGIE INTENSITY (2) (3)	CONSUMPTION ELECTRICITY FINAL	CONSUMPTION ELECTRICITY PER CAPITA	CONSUMPTION OIL PRODUCTS TOTAL (1)	CONSUMPTION OIL PRODUCTS PER CAPITA	CO2 EMISSION ELECTRICITY GENERATION	CO2 EMISSION OVERALL ENERGY SECTOR
	10^3inhab	$10^6$1995 US$	10^3Boe	1995 US$/inhab	Boe/inhab	Boe/$10^3$1995 US$	GWh	KWh/inhab	10^3Boe	Boe/inhab	10^3tons	10^3tons
	[A]	[B]	[C]	[B/A]	[C/A]	[C/B]	[D]	[D/A]	[E]	[E/A]	[F]	[G]
ARGENTINA	38.401	246.647	314.726	6.423	8,2	1,3	80.026	2.084	174.210	4,5	20.457	121.514
BARBADOS	270	1.843	1.897	6.826	7,0	1,0	782	2.895	2.495	9,2	578	1.085
BOLIVIA	8.898	8.485	19.599	954	2,2	2,3	3.665	412	15.280	1,7	1.728	8.022
BRAZIL	177.268	759.611	1.146.394	4.285	6,5	1,5	329.771	1.860	595.385	3,4	19.925	300.535
COLOMBIA	44.562	103.030	168.338	2.312	3,8	1,6	36.518	819	90.881	2,0	6.488	56.917
COSTA RICA	4.245	16.270	18.381	3.833	4,3	1,1	6.708	1.580	12.764	3,0	438	5.905
CUBA	11.306	48.360	61.984	4.277	5,5	1,3	12.469	1.103	42.355	3,7	7.225	24.711
CHILE	15.774	96.253	148.738	6.102	9,4	1,5	41.895	2.656	91.453	5,8	13.822	55.025
ECUADOR	13.343	23.749	48.047	1.780	3,6	2,0	8.366	627	49.048	3,7	3.266	20.030
EL SALVADOR	6.638	11.681	23.114	1.760	3,5	2,0	4.839	729	14.259	2,1	1.569	6.166
GRENADA	94	299	454	3.176	4,8	1,5	130	1.379	522	5,5	79	214
GUATEMALA	12.309	19.093	50.523	1.551	4,1	2,6	5.808	472	22.298	1,8	2.781	11.120
GUYANA	766	575	5.295	751	6,9	9,2	644	840	3.661	4,8	607	1.559
HAITI	8.827	3.641	12.534	412	1,4	3,4	283	32	3.964	0,4	206	1.652
HONDURAS	7.001	5.023	23.637	717	3,4	4,7	3.817	545	13.725	2,0	1.514	6.364
JAMAICA	2.651	5.379	17.554	2.029	6,6	3,3	6.516	2.458	25.313	9,5	5.695	10.917
MEXICO	103.301	484.334	701.409	4.689	6,8	1,4	160.384	1.553	636.419	6,2	113.350	369.997
NICARAGUA	5.489	4.309	16.308	785	3,0	3,8	1.653	301	9.204	1,7	1.522	3.935
PANAMA	3.116	9.842	16.678	3.159	5,4	1,7	4.359	1.399	12.893	4,1	1.610	5.465
PARAGUAY	5.922	8.731	26.853	1.474	4,5	3,1	4.315	729	9.006	1,5	0	3.911
PERU	27.148	66.143	77.056	2.436	2,8	1,2	20.206	744	51.622	1,9	3.323	24.989
DOMINICAN REP.	8.819	18.270	38.587	2.072	4,4	2,1	11.893	1.349	41.070	4,7	7.631	16.714
SURINAME	423	588	4.188	1.390	9,9	7,1	1.339	3.166	4.151	9,8	1.034	2.294
TRINIDAD & TOB.	1.307	8.157	65.582	6.241	50,2	8,0	5.876	4.496	254.216	194,5	4.458	23.122
URUGUAY	3.408	16.670	16.035	4.892	4,7	1,0	5.970	1.752	9.719	2,9	16	4.090
VENEZUELA	25.554	63.492	256.399	2.485	10,0	4,0	62.477	2.445	181.508	7,1	28.279	128.948
TOTAL	**536.840**	**2.030.474**	**3.280.308**				**820.706**		**2.367.420**		**247.599**	**1.218.205**
REGIONAL AVERAGE				**3.782**	**6,1**	**1,6**		**1.529**		**4,4**		

(*) OLADE estimate based on Energy Balances and IPCC Methodology \ Estirmación Olade con Base en Balances Energétícos y Metodología IPCC

(1) Final Consumption + Transformation Center Consumption + Own Consumption \ Consumption Final + Consumo en Centros de Transformación + Consumo Propio

(2) Final Energy Consumption / Gross Domestic Product \ Consumo Final de Energía \ Producto Bruto

(3) Information of 2003 (base year 1995) \ Informatión de 2003 (año base 1995)

Figure: Latin American and Caribbean energy consumption figures, 2003 (source: OLADE)

LAC exported 42% of its coal production in 2003 to destinations outside the region. Coal production in Latin America in 2003 was headed by Colombia (62%), followed by Mexico (18%), Venezuela (12%) and Brazil (7%). Exports come mainly from Colombia (around 80%) and Venezuela (around 18%). The largest importers are Brazil (68%) and Chile (2.1%). The main destinations for Latin America's international exports are the EU15 and North America, which together account for more than 90% of Latin America's export demand. Colombia exported around 36 million tons in 2003, which accounted for around 93% of its production of mainly low-sulphur steam coal. The main producing areas are the Guajira peninsula (Cerrejón Norte) and the Cesar province. Cerrejón Norte is one of the world largest opencast mines.

COUNTRY	PROVEN RESERVES 10^6tons	PRODUCTION 10^3tons	R / P Years
ARGENTINA	423,05	52,00	8.135,58
BARBADOS	0,00	0,00	
BOLIVIA	0,00	0,00	
BRAZIL	5.259,20	3.783,90	1.389,89
COLOMBIA	6.521,70	50.028,49	130,36
COSTA RICA	32,80	0,00	
CUBA	0,00	0,00	
CHILE	165,43	575,78	287,32
ECUADOR	22,00	0,00	
EL SALVADOR	0,00	0,00	
GRENADA	0,00	0,00	
GUATEMALA	0,00	0,00	
GUYANA	0,00	0,00	
HAITI	8,70	0,00	
HONDURAS	21,00	0,00	
JAMAICA	333,00	0,00	
MEXICO	1.838,40	9.603,74	191,43
NICARAGUA	0,00	0,00	
PANAMA	1,00	0,00	
PARAGUAY	0,00	0,00	
PERU	58,66	15,67	3.743,46
DOMINICAN REP.	0,00	0,00	
SURINAME	0,00	0,00	
TRINIDAD & TOB.	0,00	0,00	
URUGUAY	0,00	0,00	
VENEZUELA	1.288,39	6.612,71	194,84
REGIONAL TOTAL	**15.973,33**	**70.672,29**	**226,02**

Table: LAC coal reserves and production, 2003 (source: OLADE)

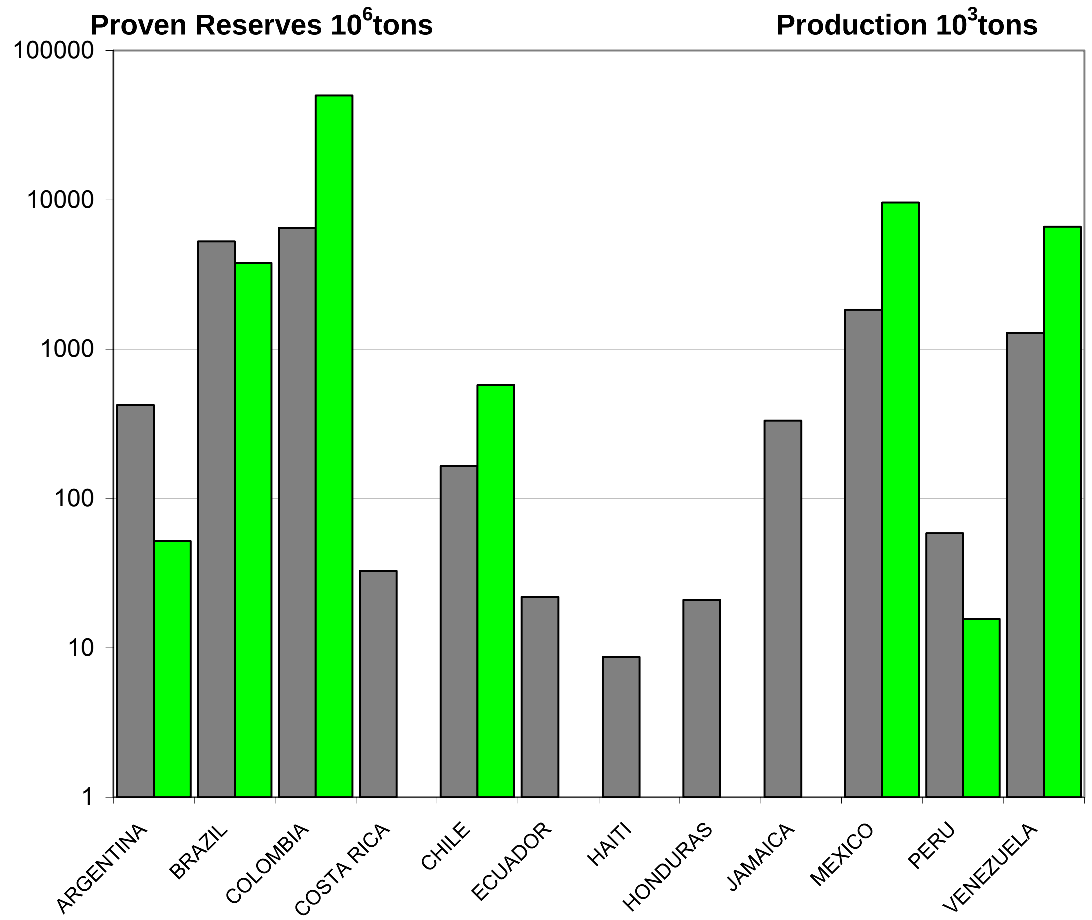


Figure: LAC coal reserves (grey) and production (green), 2003 (source: OLADE)

5.1.2 Natural gas

Latin America's proven natural gas reserves amounted to 7.5 10^{12} m^3 in 2003, 5% of the world total. Probable and possible reserves could add another 6 10^{12} m^3. Brazil's deep offshore fields are thought to have large potential and recent large discoveries in Bolivia and Trinidad and Tobago suggest that intensified exploration could lead to a substantial increase in Latin Americas proven reserves.

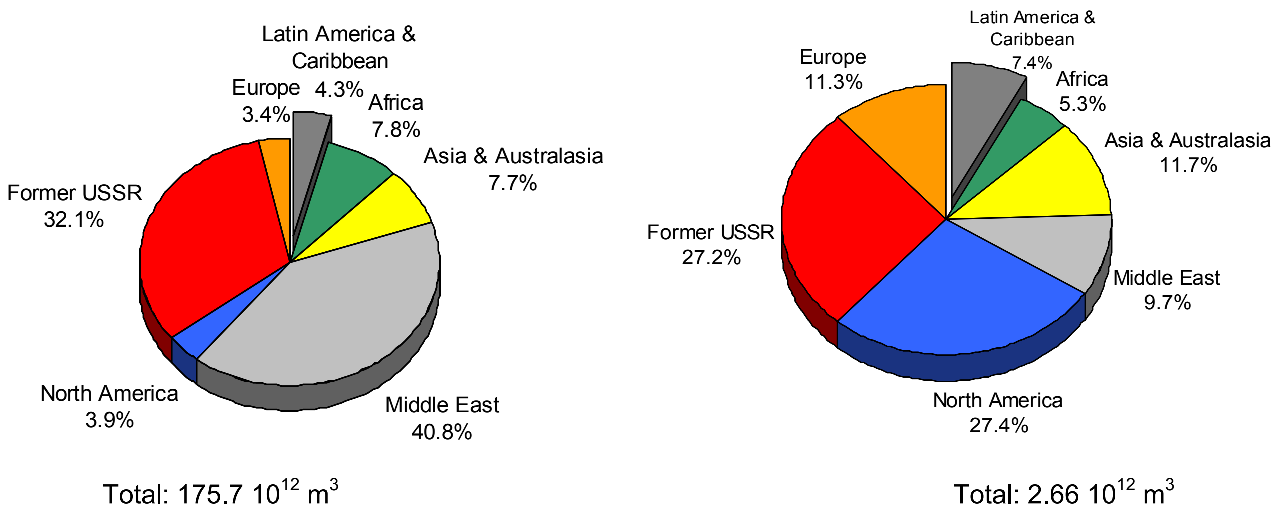


Figure: World reserves of natural gas (left) and world production of natural gas (left), 2003 (source: OLADE)

COUNTRY	PROVEN RESERVES 10^9tons	PRODUCTION 10^6tons	R / P Years
ARGENTINA	766.18	42,434.89	18.06
BARBADOS	0.11	28.95	3.80
BOLIVIA	810.70	7,624.62	106.33
BRAZIL	245.34	14,719.25	16.67
COLOMBIA	188.04	8,013.67	23.46
COSTA RICA	0,00	0,00	
CUBA	70.50	584.00	120.72
CHILE	44.00	2,175.86	20.22
ECUADOR	4.30	1,275.95	3.37
EL SALVADOR	0.00	0.00	
GRENADA	0.00	0.00	
GUATEMALA	0.60	0.00	
GUYANA	0.00	0.00	
HAITI	0.00	0.00	
HONDURAS	0.00	0.00	
JAMAICA	0.00	0.00	
MEXICO	420.51	57,633.60	7.30
NICARAGUA	0.00	0.00	
PANAMA	0.00	0.00	
PARAGUAY	0.00	0.00	
PERU	246.79	1,844.64	133.79
DOMINICAN REP.	0.00	0.00	
SURINAME	0.00	0.00	
TRINIDAD & TOB.	587.90	26,945.03	21.82
URUGUAY	0.00	0.00	
VENEZUELA	4,147.45	33,752.68	122.88
REGIONAL TOTAL	**7,532.42**	**197,033.14**	**38.23**

Table: LAC natural gas reserves and production, 2003 (source: OLADE)

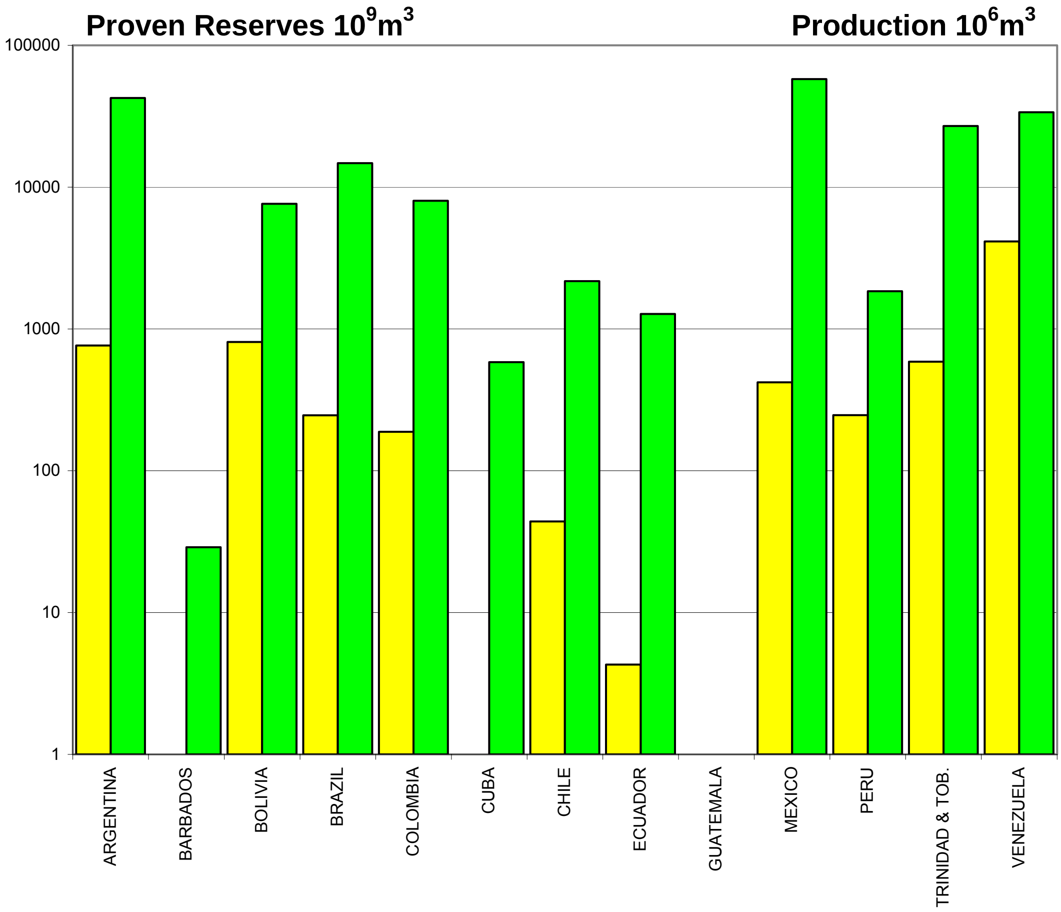


Figure: LAC natural gas reserves and production, 2003 (source: OLADE)

Venezuela holds 54% of the proven reserves, followed by Bolivia (10%), Argentina (10%), Mexico (8%) and Trinidad and Tobago (7%). Latin American natural gas production in 2003 was 197 10^9 m^3. However, gross production was much higher since large quantities of gas were re-injected and flared.

Production is expected to expand significantly over the next three decades, reaching 516 10^9 m^3 in 2030. The share of offshore production is expected to climb from the current 20% to 32% in 2030. The growth in domestic and international demand will drive this expansion. Domestic demand is expected to grow fast, from 101 10^9 m^3 in 2001 to more than 370 10^9 m^3 in 2030. Demand in the power generation sector will account for more than half of this increase, spurred by a need in many countries to reduce dependence on hydropower. Brazil is expected to lead the growth, with a spectacular 7% annual average demand growth over the next thirty years. Brazil will account for 20% of the region‘s gas demand in 2030, and will play a pivotal role in the region‘s gas infrastructure evolution.

The development of gas pipeline interconnections is most advanced in the Southern Cone [10]. Both Argentina and Bolivia have abundant non-associated gas reserves that they are eager to export to neighbouring countries. More than $7 billion have been invested in transmission pipelines over the past 10 years, including the $2.1 billion Bolivia-to-Brazil pipeline and the first stage of the $250 million Argentina-to-Brazil pipeline. Several new pipelines are planned or under construction, providing the basis for a sub-regional gas transportation network.

[10] The Southern Cone encompasses Brazil, Argentina, Chile, Bolivia, Paraguay and Uruguay

Large gas reserves in the North offer potential for LNG projects. Trinidad and Tobago operates a three-train liquefaction plant (9.6 million tons per year) and exported 5.4 10^9 $m^3$of LNG in 2002, mainly to the United States. A fourth train is being built and a fifth is planned. Venezuela has enough gas reserves to become a major LNG exporter, but projects for liquefaction plants have been stalled by a combination of poor economics and lack of political support.

Bolivia is also investigating using some of its reserves for an LNG plant on the coast in Chile or in Peru, which would allow exports to the United States or Mexico. Peruvian gas from the giant Camisea field might also be exported as LNG. The region's LNG exports are expected to grow rapidly over the next three decades, potentially reaching 90 10^9 m^3 in 2030. This would require more than $15 billion in LNG liquefaction plants alone.

5.1.3 Oil

Latin American production of crude oil and LNG averaged 9.4 mb/d in 2003 and is expected to increase to almost 12 mb/d by 2030. Production is dominated at present by Venezuela, Mexico and Brazil, with output in Argentina, Colombia and Ecuador accounting for most of the rest. The region's proven oil reserves stood at 114.5 billion barrels at the end of 2003, i.e. 10% of the world total.

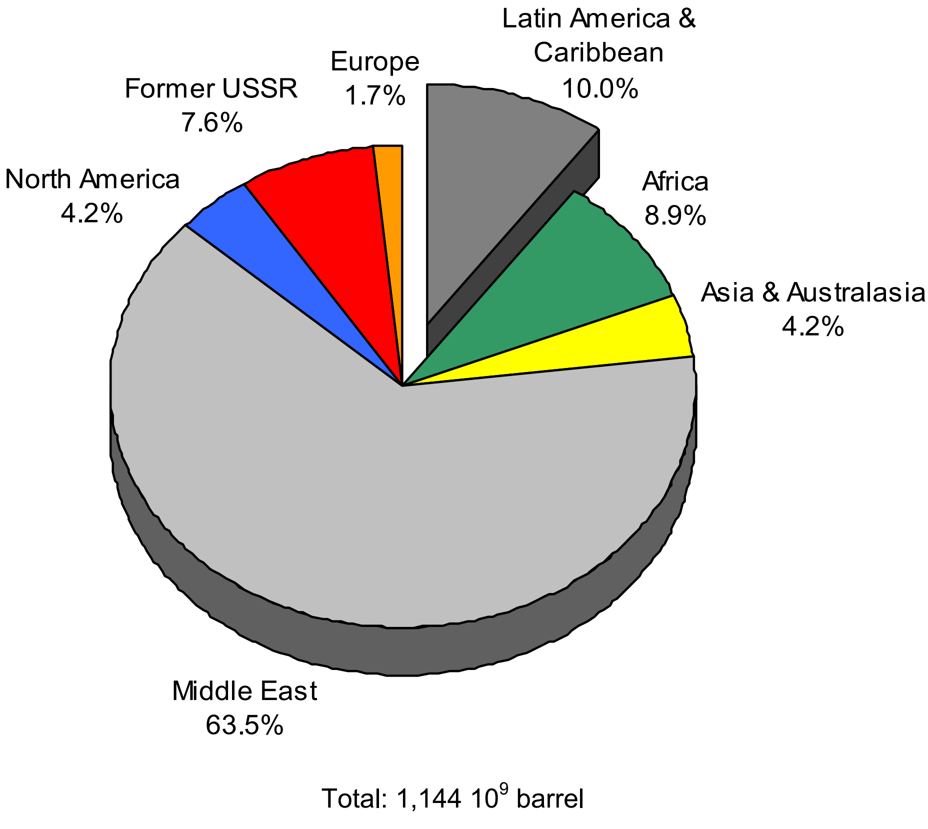


Figure: World oil reserves 2003 (source: OLADE)

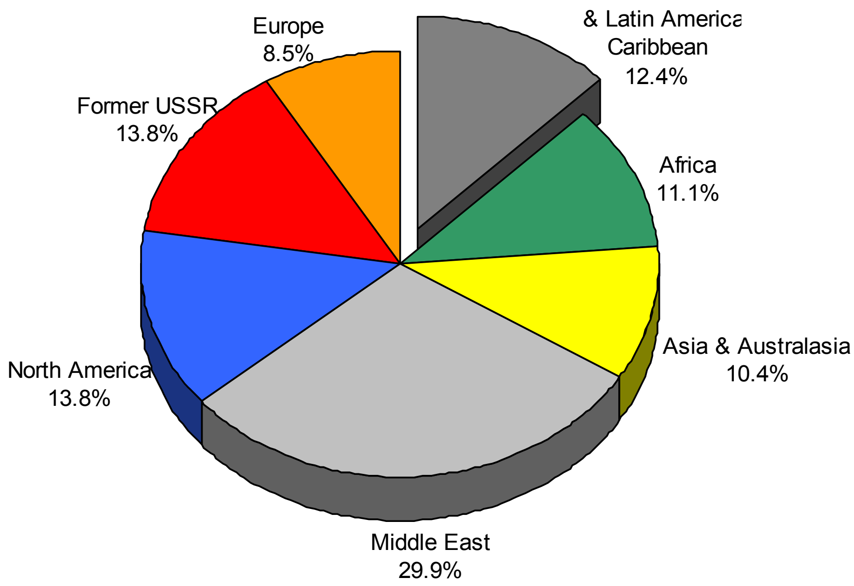


Figure: World oil production 2003 (source: OLADE)

COUNTRY	PROVEN RESERVES 10^6bbl	PRODUCTION 10^3bbl/day	R / P Years
ARGENTINA	3,258.80	740.71	12.05
BARBADOS	2.51	1.61	4.28
BOLIVIA	486.11	33.35	39.93
BRAZIL	10,601.91	1,540.66	18.85
COLOMBIA	1,542.40	541.33	7.81
COSTA RICA	0.00	0.00	
CUBA	74.50	79.93	2.55
CHILE	29.00	3.62	21.93
ECUADOR	5,060.00	417.80	33.18
EL SALVADOR	0.00	0.00	
GRENADA	0.00	0.00	
GUATEMALA	493.15	24.73	54.63
GUYANA	0.00	0.00	
HAITI	0.00	0.00	
HONDURAS	0.00	0.00	
JAMAICA	0.00	0.00	
MEXICO	14,119.60	3,377.79	11.45
NICARAGUA	0.00	0.00	
PANAMA	0.00	0.00	
PARAGUAY	0.00	0.00	
PERU	374.05	91.35	11.22
DOMINICAN REP.	0.00	0.00	
SURINAME	110.00	11.78	25.58
TRINIDAD & TOB.	990.00	134.68	20.14
URUGUAY	0.00	0.00	
VENEZUELA	77,383.31	2,404.06	88.19
REGIONAL TOTAL	**114,525.34**	**9,403.41**	**33.37**

Table: LAC oil reserves and production, 2003 (source: OLADE)

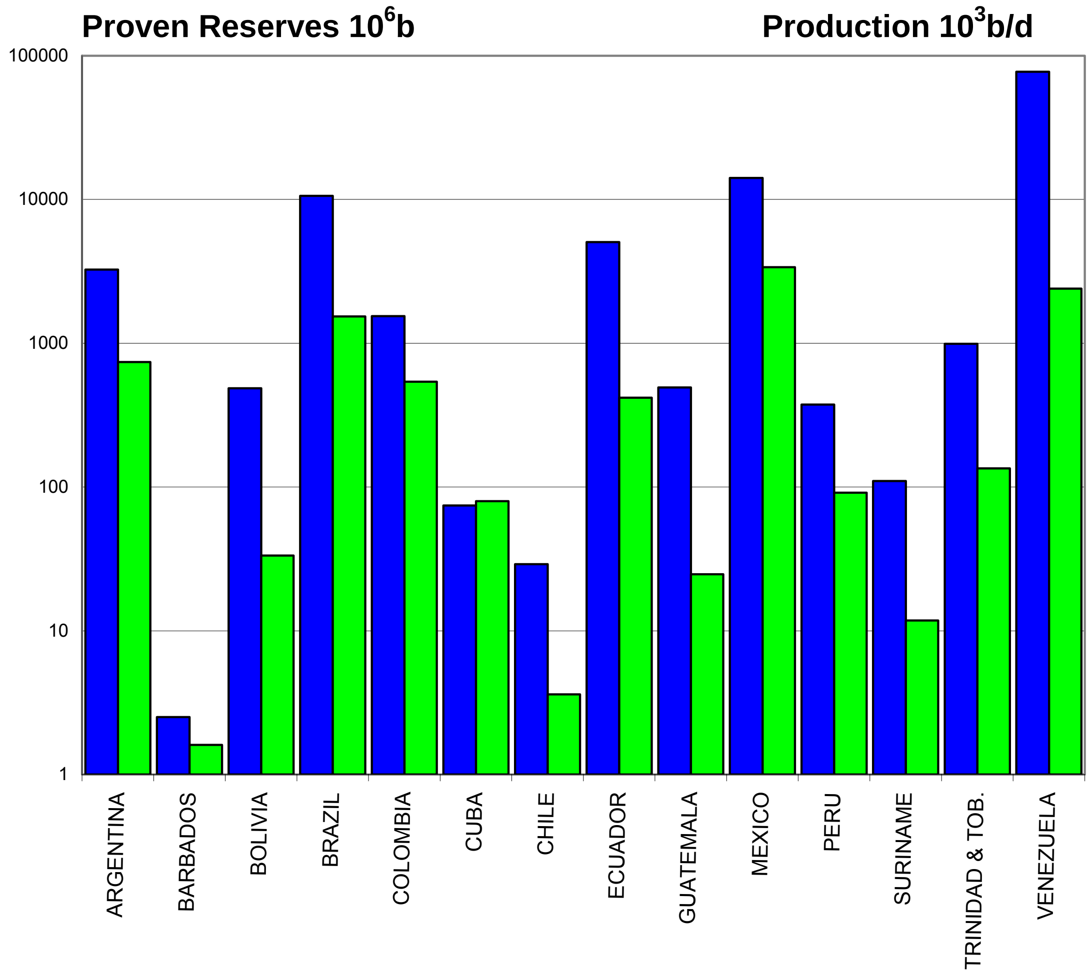


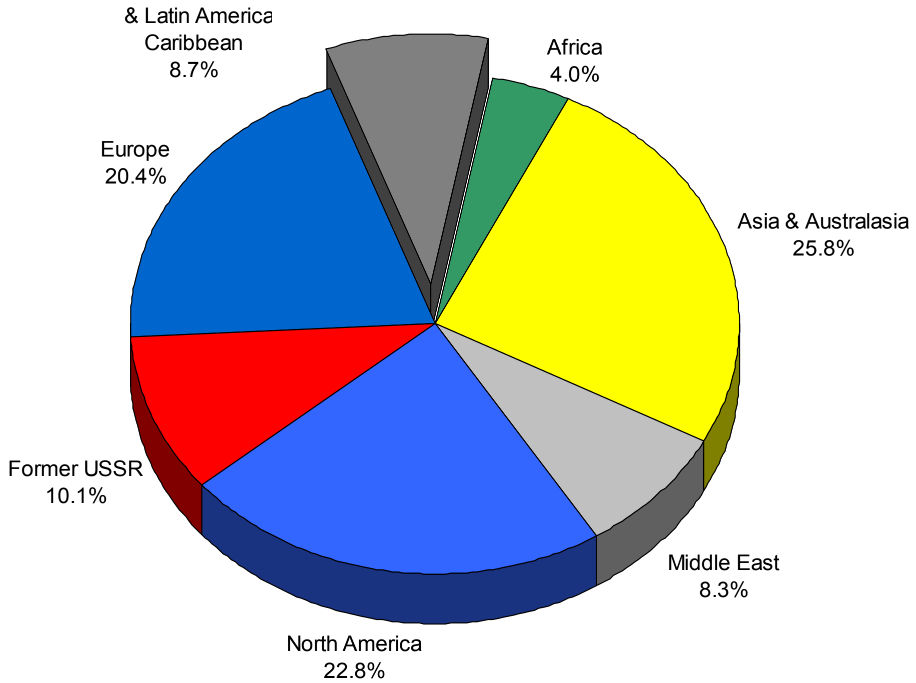
Figure: LAC oil reserves and production, 2003 (source: OLADE)

Compared to the world oil refining capacities LAC has a share of almost 9% (see figures below). With a capacity of 7.2 10^6 b/d the region exports approximately 5.8 10^6 b/d oil and oil products which accounts for ca. 81% of its daily refining capacity.

COUNTRY	OIL REFINING CAPACITY	EXPORTS (1)		IMPORTS (1)	
		OIL	OIL PRODUCTS.	OIL	OIL PRODUCTS
ARGENTINA	625.00	229.81	149.20	2.70	5.10
BARBADOS	0.00	1.61	0.00	0.00	6.99
BOLIVIA	54.00	2.71	0.58	0.00	5.54
BRAZIL	2,041.51	248.97	245.68	361.75	166.01
COLOMBIA	396.00	229.83	65.42	1.17	0.87
COSTA RICA	25.00	0.00	0.14	10.45	29.50
CUBA	150.00	0.00	0.00	26.99	60.30
CHILE	227.00	0.00	34.33	201.73	52.45
ECUADOR	184.00	252.32	38.43	0.00	33.82
EL SALVADOR	44.04	0.00	3.41	19.14	26.44
GRENADA	0.00	0.00	0.00	0.00	1.56
GUATEMALA	22.50	22.59	0.00	0.00	64.81
GUYANA	0.00	0.00	0.00	0.00	10.28
HAITI	0.00	0.00	0.00	0.00	11.09
HONDURAS	0.00	0.00	0.64	0.00	38.88
JAMAICA	35.00	0.00	2.51	17.25	55.64
MEXICO	1,540.00	1,864.07	169.85	0.00	189.09
NICARAGUA	20.00	0.00	0.00	17.10	8.70
PANAMA	60.00	0.00	3.83	0.00	40.03
PARAGUAY	7.50	0.00	0.00	1.63	23.98
PERU	159.30	28.90	41.13	83.37	37.26
DOMINICAN REP.	52.00	0.00	0.00	40.89	77.73
SURINAME	7.00	1.52	0.97	0.00	5.70
TRINIDAD & TOB.	175.00	71.53	97.54	86.04	19.99
URUGUAY	50.00	0.00	9.97	32.85	6.08
VENEZUELA	1,294.40	1,549.28	474.92	0.00	0.00
REGIONAL TOTAL	**7,170.15**	**4,503.15**	**1,338.56**	**903.09**	**977.82**

(1) Includes intra-regional trade
Oil products: (LPG+Gasolines+Kerosine+Jet Fuel Oil+DieselOil)

Figure: Regional Trade and Oil Refining Capacity 2003 (in 10^3 b/d) (source: OLADE)



Total: 82,694 10^3 b/d

Figure: World Refining Capacity 2003 (source: OLADE)

5.2 Structure of the LAC power sector

The power market of Latin America and the Caribbean is composed of 34 countries of different size, different economical power and different indigenous energy resources. As different as these countries are as diverse are the interests and objectives concerning their energy policies and strategies for the future.

A more detailed country-by-country analysis of the leading LAC countries in the power market is presented in Annex 2.

5.2.1 Main players in the sector

Apart from the commercial players in the power sector there are some organisations to be mentioned that play a leading role in the sector's development (see Annex 3).

The Latin American Energy Organization (OLADE) is an international public cooperation, coordination and advisory entity, essentially aimed at promoting the integration, protection, conservation, rational use, marketing and defense of the region's energy resources.

CIER is a Non Governmental Organization comprising the electric utilities and organisations linked with the national electric sectors of ten South American countries and three Associated Members. The main objective of this non-profit international organization is to promote and encourage the integration of the regional electric sectors.

In the oil and gas sector ARPEL is playing the leading role in LAC. ARPEL is formed by more than twenty-five oil and natural gas companies, which represent over 90% of the region's upstream and downstream sectors. Regional integration, a proactive participation in the development process of laws and regulations, the development of cooperation programs with international organizations and the care of the industry's public image are important objectives for the Organization.

Commercial players in the oil and gas sector are internationally operating companies like Repsol, Texaco, BP, Mobil, etc.

With regard to financing of projects in the LAC energy sector IDB and CAF (despite the World Bank) have to be highlighted as major players.

Since its founding in 1959, the IDB has become a major catalyst in mobilizing resources for the region. The IDB provides loans and technical assistance to 26 countries in Latin America and the Caribbean using capital provided by its member countries, as well as resources obtained through bond issues in international capital markets.

The Andean Development Corporation (CAF) is also a multilateral financial institution that promotes the sustainable development of its shareholder countries and regional integration. CAF's mission is to promote sustainable development and regional integration by attracting capital resources to provide a wide range of financial services, with high value added, to the public and private sectors of our shareholders countries.

Internationally operating companies mainly from South Europe and the United States dominate the power market of LAC – as is detailed in the following paragraphs. In addition Annex 4 summarises their stakes in LAC enterprises in tabular form.

A more detailed insight into the LAC power market and its national and international players is provided in Annex 3.

Commercial players in the power market

Endesa (Spain)

This is the largest Spanish electricity company, which has been active in Latin America from the early 1990s. Endesa has stated that it will stop expanding operations in Latin America as it tries to obtain returns on recent investments that have brought it control of 10% of the continent's electricity sector. The company is insisting on higher returns than it obtains in Europe, to justify the risks on Latin American investments and to recoup previous losses. Although Endesa plans to invest $2.9bn in Latin America over the next few years, this will be to maintain its existing assets rather than new investment. Endesa is actively seeking more local partners, so that investment will come from local sources rather than Spain.

Endesa's Chilean subsidiary, Enersis, had to carry out a major financial restructuring in 2002, arranging an extra $2.3bn loans to avoid having to repay existing loans. In Brazil, however, Endesa decided to reinvest in its distribution companies rather than agree to a refinancing arrangement with Brazilian bank BNDES (as was done by other companies, eg AES). In Argentina Endesa is centrally involved in negotiations with the government to try and retain its investments, reclaim the dollarisation agreement and increase electricity prices to improve profits.

Iberdrola (Spain)

Iberdrola is a Spanish company with investments in Brazil, Bolivia, Guatemala and Mexico. Its main presence is in a group of distribution companies in the northeast of Brazil. It has recently invested in a 520 MW gas-fired generator in the region, all of the output from which will be bought by Iberdrola's distribution companies. The cost of this investment is all derived from the surplus of the Brazilian energy operations, not from capital from Spain. Two of Iberdrola's Brazilian distribution companies, Coelba and Cosern, have recently decided to issue bonds worth $143m and $40m respectively: again, this is local money borrowed by the local operators, who all (including the third one, Celpe) have their own independent credit ratings, not funds from Iberdrola.

Union Fenosa (Spain)

Union Fenosa is present in a number of countries, including a number of operations in Central America: Guatemala, Mexico, Panama, Nicaragua, and is constructing a plant in Costa Rica. Union Fenosa's profits in Latin America increased in 2003, but the company strategy is to reduce its investments in the area, if they cannot produce higher returns.

Its distribution operations in Dominican Republic were re-nationalised in 2003 (with compensation).

EdP (Portugal)

EdP (Electricidade do Portugal) is the mainly state-owned electricity company of Portugal. It is active internationally principally in areas of former Portuguese influence, most especially Brazil. In Brazil it owns stakes in distribution and generation companies, notably Bandeirante (Sao Paulo), and a minority 15% stake in Cerj (Rio). It also owns a minority stake in a distributor in Guatemala.

EdF (France)

EdF (Electricite de France) is the French electricity company, which is 100% state-owned. It is active internationally in all continents. In Latin America it has invested in operations in electricity generation and distribution in Argentina and Brazil, and also in generation in Mexico. Its total turn-over in Latin America in 2003 was €1,763 million, about 4% of its total business. In 2003 operations in Mexico were profitable and profitability improved in its operations in Argentina and Brazil, but it lost nearly €1 billion with its Brazilian distributor Light. EDF's strategy is now to concentrate on Europe.

In 2003 EDF brought arbitration cases to the World Bank's International Centre for Settlement of Investment Disputes (ICSID) against the Argentinean government against the ending of dollarisation. EDF has also approached banks to begin restructuring the financial liabilities of its subsidiaries. It has demanded price rises for its distribution companies, but the Argentinean government has not conceded them, but has instead imposed fines because of blackouts that have occurred since 2001. In July 2004 EDF announced it is selling its stake in one Argentinean distributor Edemsa (Mendoza province) to a local business group.

Tractebel – Suez (France)

Tractebel is the energy division of Suez, and an active energy multinational company. It has major stakes in generating companies in Brazil, Chile, and Peru and Mexico (as well as some gas distribution companies in Mexico). It has suspended investment in Brazil for the last two years and will not invest further until it is satisfied on government policies. Tractebel complains that the current policies put Tractebel "in an unfair position by forcing it to compete with state-controlled generators".

AES (USA)

AES is a global multinational electricity company. It is based in the USA, but has a relatively small proportion of its business there; it also operates in Europe, Asia and Africa. Half its total business is in Latin America, with investments in Argentina, Brazil, Chile, Colombia and Venezuela; and in Dominican Republic, El Salvador, Honduras, Mexico, and Panama.

AES has restructured globally in 2002 and 2003, including the sale of 14 subsidiaries (all in regions other than Latin America). In Latin America it has increased its stake in many companies, buying shares from other multinationals who are leaving: it was effectively forced to take over the shares in four companies abandoned by its partner PSEG. It has systematically renegotiated the debts of all its subsidiaries in Brazil - after defaulting on the loans due from its subsidiary Eletrobras - and in Chile. In Dominican Republic, where it owns both generators and distributors, it has been involved in bitter disputes with the government: AES shut down its generators to force the government to make payments, and is now planning to sell the distributor. In Venezuela, AES promised Union Fenosa the right to buy some assets in Colombia in return for its agreement not to enter a bidding war for the Venezuelan utility.

In Argentina, AES notes that "In 2003, the political and social situation in Argentina showed signs of stabilization, the Argentine peso appreciated to the U.S. dollar, and the economy and electricity demand started to recover" and that renegotiation of utilities concessions remains open until the end of 2004. AES does not appear to be taking arbitration cases, except in respect of some gas transmission business. In 2004 Buenos Aires province introduced a law obliging distributors, including AES-owned Eden and Edes, to provide a minimum of electricity to consumers.

CMS Energy (USA)

CMS is a US energy company with 6m customers in Michigan. It has expanded to operate internationally, on all continents. Its investments in Latin America have included electricity generating and distribution companies, in Argentina, Brazil, Chile and Venezuela.

In 2004 CMS announced a loss of $400m on its Argentinean operations. It has taken court cases against the government of Argentina's devaluation of the Peso and ending of 'dollarise' contracts. In October 2001, CMS Energy decided to discontinue the operations of its international energy distribution business (including CPEE, which it had bought in 1999), but in 2003, it reclassified as continuing operations SENECA, which is its energy distribution business in Venezuela, and CPEE, which is its energy distribution business in Brazil, due to its inability to sell these assets. If these sales succeeded CMS' only presence in electricity in Latin America, outside Argentina, would be its investment in the Taltal generating plant in Chile, which is linked to the Gasatacama pipeline - CMS owns 50% of Gasatacama.

El Paso (USA)

El Paso owns two generating companies in Brazil and has minority stakes in generating companies in Argentina, Mexico, and Peru. During 2003 El Paso abandoned its investments in, in the generating companies CAPSA and CAPEX in Argentina. El Paso also has significant operations in gas transmission pipelines in Latin America, including Argentina, Bolivia, Brazil, Chile, Mexico and Venezuela.

PSEG (USA)

PSEG is a USA-based multinational which expanded internationally in the 1990s, under the name of PSEG Global. It developed activities in a number of Latin American countries, often in partnership with AES. It also has subsidiaries in Europe (Poland), North Africa (Tunisia) and Asia (China, Hong Kong and India). The Polish government is currently trying to buy out PSEG Global's IPPs in that country because they are too expensive.

Up to 2002 PSEG's global investments were profitable but have since been affected by general resistance to privatisation and political, economic and social crises especially in Argentina, Brazil and Venezuela. PSEG Global is now reviewing all its international investments and is trying to sell many of its investments. In 2003 it simply abandoned its investments in Argentina, by giving its shares to its partner AES.

Its remaining activities are in electricity distribution companies in Brazil, Chile, and Peru; and a combined generation and distribution company in Venezuela. These are now profitable but PSEG Global but still fears that "adverse political and economic risks associated with this region could have a material adverse impact on its remaining investments in the region". 4

Petrobras (Brasil)

Petrobras Energía Participaciones is Petrobras' main international asset. It is an integrated energy company with operations in Argentina, Venezuela, Brazil, Peru, Bolivia and Ecuador. It is involved in oil exploration etc, and in electricity only in Argentina. It originated in a takeover in October 2002, when Petróleo Brasileiro (Petrobras) acquired a 58.62% interest in Perez Companc S.A., whose only asset was its 98.21% stake in Pecom Energía S.A..

Others

There are one or two cases of other Latin American electricity companies operating outside their own home country. The Chilean power company Enersis expanded into generation and distribution activities in a number of other countries during the 1990s. However, Endesa of Spain was always a minority shareholder, and in 1999 Endesa bought 60% of Enersis. It is therefore treated as a subsidiary of the Spanish multinational Endesa, not as an independent Chilean energy company.

5.2.2 Tariffs, Clients

It is difficult to compare average electricity prices among the countries of the region because of diverse rate systems, variable exchange rates, and increased participation by self-generators, co-generators and unregulated users, whose prices are not always available. In order to provide a reference, the prices are converted into US Dollars based on the average monthly prices that are reported in local currency.

On that basis and the assumption that the average prices for December 2003 are representative for the coming year, the average consumption figures for each country were used to calculate the weighted prices for the region. The following are the approximate average electricity prices in Latin America and the Caribbean, including taxes, in:

7.7 US cents per kWh for residential users,

8.1 US cents per kWh for commercial users, and

4.8 US cents per kWh for industrial users.

The differences among the countries are large, as can be seen in the Economic-Energy Information System (SIEE) that is kept by OLADE (see table below).

The countries with the lowest electricity prices (less than 5 US cents per kWh) were Trinidad and Tobago and Argentina. Those with average prices higher than 14 cents per kWh were Grenada, Barbados, Jamaica, Nicaragua and Suriname. Much of this, as noted above, is distorted by variations in the exchange rate.

Electrical coverage was one of the most difficult aspects to evaluate due to the lack of information in many countries on the percentage of homes that have electrical service. There are countries like Barbados and Costa Rica that have reported coverage in the order of 98%, and others such as Haiti, Nicaragua, Honduras, and Bolivia that report figures of 34%, 55%, 62%, and 65% respectively. It was even more difficult to break down this indicator in order to estimate electrical coverage in rural areas.

PAIS	MONEDA	PARIDAD	COMBUSTIBLES [US$/Galón – DOMESTIC FUELS [US$/Gallon							ELECTRICIDAD - ELECTRICITY US cent/kWh		
COUNTRY	NACIONAL [M.N.] NATIONAL CURRENTLY [N.C.]	M.N./US$ EXCHANGE RATE N.C./US$	GASOLINA REGULAR REGULAR GASOLINE	GASOLINA EXTRA PREMIUM GASOLINE	DIESEL OIL	KEROSENE DOMESTICO HOUSEHOLD KEROSENE	JET FUEL	FUEL OIL	GAS L.P. L.P.G. US$/kg	RESIDENCIAL RESIDENTIAL	COMERCIAL COMMERCIAL	INDUSTRIAL INDUSTRIAL
ARGENTINA	Pesos	2.91	2.15	2.38	0.24	1.54	1.29	0.80	0.34	4.14	4.44	2.08
BARBADOS	Barbadian Dollar	2.00	n/a	2.63	1.31	1.19.	0.40	0.40	1.26	18.80	19.95	19.65
BOLIVIA	Boliviano	7.83	1.61	1.83	1.51	1.04	1.21	1.06	0.28	5.49	8.43	3.98
BRAZIL	Real	2.89	2.62	2.53	1.82	1.28	1.15	0.74	0.77	8.27	7.27	3.84
COLOMBIA	Peso Colombiano	2,780.82	1.56	2.14	1.08	1.09	1.06	0.66	0.32	7.70	9.24	7.17
COSTA RICA	Colón	418.53	2.30	2.41	1.69	1.70	1.60	0.69	0.84	6.19	8.58	5.96
CUBA	Peso Cubano	1.00	1.51	1.89	1.08	0.32	1.14	0.73	0.24	14.26	10.45	8.35
CHILE	Peso Chileno	589.42	1.87	1.89	1.62	1.50	0.61	0.77	0.80	8.56	8.21	5.56
ECUADOR	Dólar	1.00	1.31	1.68	0.90	n/a	1.16	0.69	0.11	13.03	11.11	9.65
EL SALVADOR	Colón Salvador	8.75	1.90	2.03	1.56	1.39	0.89	1.42	0.39	12.85	11.89	12.10
GRENADA	Grenadian Dollar	2.70	n/a	2.03	1.54	1.14	n/d	n/d	0.98	22.10	23.40	18.80
GUATEMALA	Quetzal	8.04	1.87	1.93	1.37	1.55	1.20	1.14	0.51	7.93	6.21	7.48
GUYANA	Guyanese Dollar	194.25	n/a	2.07	1.60	1.24	0.00	0.99	0.00	0.00	0.00	0.00
HAITI	Gourde	42.08	1.81	1.96	1.23	1.11	1.11	0.31	0.35	5.99	8.84	8.45
HONDURAS	Lempira	17.75	2.45	2.52	1.80	1.56	0.83	0.94	0.77	4.41	2.88	3.44
JAMAICA	Jamaican Dollar	60.52	1.63	1.76	1.50	1.42	1.13	0.78	0.60	17.44	15.03	11.55
MEXICO	Nuevo Peso	11.24	n/a	2.28	1.69	n/a	1.05	0.67	1.08	8.09	13.95	6.95
NICARAGUA	Córdoba de Oro	15.55	2.14	2.22	1.88	1.80	0.67	0.43	0.55	13.47	16.24	12.61
PANAMA	Balbao	1.00	1.83	1.87	1.44	0.99	1.00	0.75	0.63	12.10	11.80	9.90
PARAGUAY	Guaraní	6,114.96	1.91	2.41	1.52	0.49	0.48	0.42	0.46	5.60	5.97	3.76
PERU	Nuevo Sol	3.46	2.48	3.22	2.10	2.10	n/d	0.86	0.92	11.37	7.59	7.20
REP. DOMINICANA	Peso Dominicano	37.25	1.61	1.82	1.21	1.22	1.11	1.20	0.32	9.53	10.60	10.82
SURINAME	Florin	401.00	n/a	2.11	1.55	1.36	1.36	0.25	0.72	17.10	17.30	13.10
TRINIDAD Y TOBAGO	Trinidad Dollar	6.30	1.24	1.30	0.77	0.61	1.26	0.51	0.37	3.51	3.73	4.62
URUGUAY	Peso Uruguayo	29.30	2.92	3.24	1.91	2.03	1.65	0.64	082	10.55	7.03	3.89
VENEZUELA	Bolivar	1,598.00	0.15	0.20	0.12	0.28	0.29	0.12	0.14	5.50	7.90	2.80

1 barrel = 42 US gallons = 158.98 liters / 1 barril = 42 galones US = 158.987 litros

NOTAS: n/a no aplicable
n/a no disponible
* datos preliminares

NOTES: n/a not applicable
n/a not available
* preliminary data

Figure: Energy Prices and Electricity Tariffs including Taxes, December 2003 (source: OLADE)

Using the latest coverage figures available and the total population of each country, the number of inhabitants per home was estimated, and on that basis, it was concluded that approximately 91% of the homes in the region have electricity.

5.2.3 Power grid network structure

Many countries move towards integration, including the Central Americans countries, through the implementation of the SIEPAC (Sistema de Interconexión Eléctrica de los Países de América Central) project under the Framework Agreement of the Central American Electrical Market, and the creation of the Regional Electricity Market, after having established regional entities over a period of several years such as CEAC (Central America Electrification Council), Regional Electric Interconnection Commission (CRIE), Regional Operation Entity (EOR), and Network Owner Enterprise (EPR).

It is important to note that in addition to the local generating plants in each country, with each year that passes, more countries are becoming interconnected with others, allowing them to make the best use of the reserves and complementarities of the supply, as well as the non-simultaneities of the demand.

An important achievement in 2003 was the regulatory harmonization between Colombia and Ecuador that permitted the interconnection and synchronous operation of their national electrical systems.

The figure below shows the status of the main interconnection power lines between the countries of South America. Reference is made to operating connections (Interconexion operativa), connections under construction (Interconexion en construccion), projected connections (Interconnexion en proyecto) and planned connections (Interconexion en studio).

According to the numbers given in the figure the following table details the characteristics of the interconnections. It becomes obvious that there are regions operating with different power frequencies as is also highlighted in the figure (bottom, left): the southern countries operate on 50 Hz whereas the northern countries operate on 60 Hz frequencies, what makes the interconnections between those countries even more difficult.

The six Central American countries are already interconnected by 230 kV power lines. They are building a parallel 230 kV power line to reinforce their interconnection.

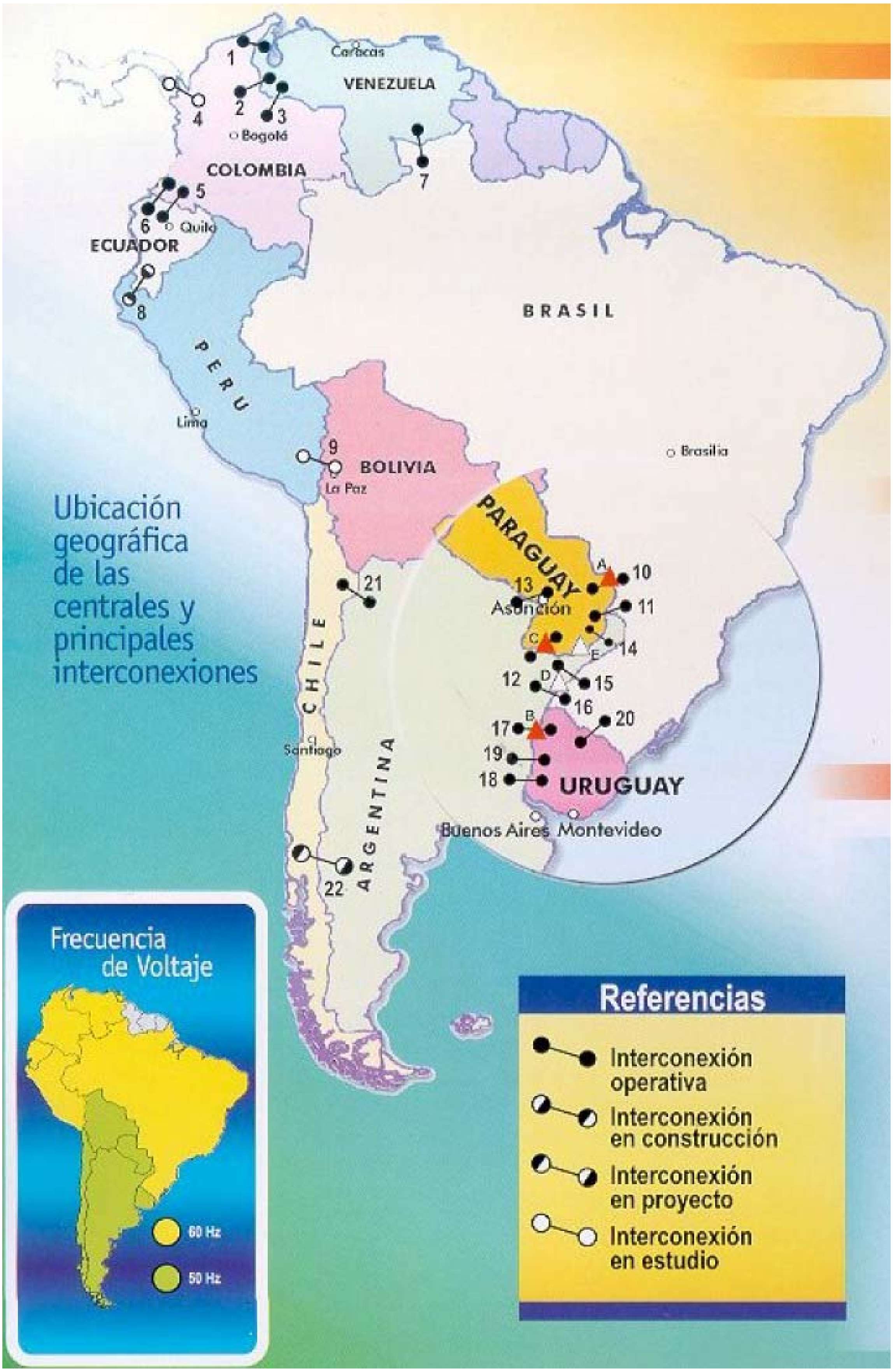


Figure: Power network of South American countries, 2002 (source: CIER)

Country: Location	**Country**: Location	V (kV)	Power (MW)	Notes
Colombia: Ipiales	**Ecuador**: Tulcán	115/138	40	Operatine (60 Hz)
Argentina: Paso de los Libres	**Brasil**: Uruguayana	132/230	50	Operatine (50/60 Hz)
Brasil: Foz de Iguazú	**Paraguay**: Acaray	138	60	Operatine (50/60 Hz)
Brasil: Rivera	**Uruguay**: Libramento	230/150	70	Operatine (50/60 Hz)
Argentina: Clorinda	**Paraguay**: Guaramberé	132/220	80	Operatine (50 Hz)
Colombia: Tibú	**Venezuela**: La Fría	115	80	Operatine (60 Hz)
Colombia: Pasto	**Ecuador**: Quito	230	260	Operatine (60 Hz)
Argentina: Yacyreta	**Paraguay**: Yacyreta	500/220	800/130	Operatine (50 Hz)
Colombia: Cuestecita	**Venezuela**: Cuatricentenario	230	150	Operatine (60 Hz)
Colombia: San Mateo	**Venezuela**: Corozo	230	150	Operatine (60 Hz)
Brasil: Boa Vista	**Venezuela**: Santa Elena	230/400	200	Operatine (60 Hz)
Chile: Norte Grande Chile (SING)	**Argentina**: Cobos	345	643	Operatine (50 Hz)
Argentina. Rincón	**Brasil**: Garabí	500/525	2,000	Operatine (50/60 Hz)
Argentina: Salto Grande	**Uruguay**: Salto Grande	500	1,750	Operatine (50 Hz)
Brasil: Itaipú	**Paraguay**: Itaipú	750CC/220	10,787	Operatine (50/60 Hz)
Colombia	**Panamá**	230		Under study
Ecuador: Machala	**Perú**: Zorritos	230/220	60 (200)	Under construction (60 Hz)
Bolivia: La Paz	**Perú**: Puno	230/220	150	In study
Argentina: El Dorado	**Paraguay**: Mcal A. Lopez	132	33.6	Operating (50 Hz)
Argentina: Colonia Elia	**Uruguay**: San Javier	500	1000	Operating (50 Hz)
Argentina: Conceptión	**Uruguay**: Paysandú	132/150	100/50	
Argentina: C.H. Ailcura	**Chile**: Valdivia	220	250	Projected
Central American Intercn.	**The six Countries**	230	250	Operating (60 Hz)

Table: Power network interconnections in LAC, 2004 (source: OLADE)

5.2.4 Electricity exports in the region

In 2003 international transactions in the region (including those to the United States) have been in the order of 49,000 GWh p.a. The largest exporter of electrical power in 2003 was Paraguay with 45,173 GWh p.a., and the country that imported most was Brazil, with 37,141 GWh p.a. It is envisaged that new interconnections that are being implemented or under study will cause electrical power transactions between the Central American and South American countries to increase.

In general the region is a net exporter of electricity and has exported 2,979 GWh to the United States in 2003.

11.1 IMPORTACION DE ELECTRICIDAD (GWh)				Tasa de Crecimiento (%)	
Paises	1994	2002	2003	94-03	02-03
ARGENTINA	1.774.00	8.780.29	7.578.00	17.51	-13.69
BARBADOS					
BOLIVIA	0.00	9.20	9.38		1.96
BRASIL	31,758.69	36,570.43	37,141.28	1.75	1.56
COLOMBIA	279.50	7.57	68.90	-14.41	810.17
COSTA RICA	0.00	36.25	41.05		13.24
CUBA					
CHILE	0.00	1,812.81	1,667.04		-8.04
ECUADOR	0.00	56.30	1,119.61		1,888.65
EL SALVADOR	32.00	412.59	427.60	33.38	3.64
GRENADA					
GUATEMALA	42.00	54.90	30.54	-3.48	-44.37
GUYANA					
HAITI					
HONDURAS	62.00	415.15	331.34	20.47	-20.19
JAMAICA					
MEXICO	1,140.00	531.11	71.11	-26.53	-86.61
NICARAGUA	97.10	15.12	11.80	-20.88	-21.96
PANAMA	58.00	35.15	2.29	-30.16	-93.48
PARAGUAY					
PERU					
REP: DOMINICANA					
SURINAME					
TRINIDAD Y TOBAGO					
URUGUAY	15.10	559.30	433.72	45.22	-22.45
VENEZUELA					
AL&C	35,258.39	49,296.18	48,933.67	3.71	-0.74

11.2 EXPORTACION DE ELECTRICIDAD (GWh)				Tasa de Crecimiento (%)	
Paises	1994	2002	2003	94-03	02-03
ARGENTINA	19.00	2.860.86	2.543.00	72.30	-11.11
BARBADOS					
BOLIVIA	2.00	0.00	0.00		
BRASIL	0.00	7.00	6.00		-14.29
COLOMBIA	0.00	618.30	1,182.00		91.17
COSTA RICA	6.00	439.83	117.74	39.20	-73.23
CUBA					
CHILE					
ECUADOR	0.00	0.00	67.01		
EL SALVADOR	43.00	29.59	102.50	10.13	246.46
GRENADA					
GUATEMALA	31.00	439.80	427.79	33.86	-2.73
GUYANA					
HAITI					
HONDURAS	6.00	0.00	0.00		
JAMAICA					
MEXICO	1,970.00	343.89	953.06	-7.75	177.14
NICARAGUA	118.00	6.98	20.90	-17.50	199.43
PANAMA	81.00	48.64	182.13	9.42	274.42
PARAGUAY	31,877.90	41,769.99	45,172.61	3.95	8.15
PERU					
REP: DOMINICANA					
SURINAME					
TRINIDAD Y TOBAGO					
URUGUAY	1,675.80	2,287.21	1,138.37	-4.21	-50.23
VENEZUELA					
AL&C	35,829.70	48,852.09	51,913.11	4.21	6.27

Figure: Import (top) / export (bottom) of electricity in LAC countries (in GWh), 2003 (source: OLADE)

5.3 Fossil fuelled power plants in LAC (Technologies and Statistics)

The following evaluation of the power plant technologies in LAC has been derived from the Energy-Economic Information System (SIEE) operated by OLADE. Organisations in the LAC countries are appointed to keep the database updated by providing regular information to OLADE.

However, the database on thermal power plants and their technologies shows minor gaps of data. This can be recognised by comparing the total installed capacity of 121 GW (without hydropower) in the region to the corresponding calculated installed capacity of 104 GW based on the power plant database. Nonetheless, an error of 14% (i.e. 17 GW difference) seems to be tolerable and does not adversely affect the representativity of the evaluation.

Finally, the evaluation shall give a picture of the situation in the power sector and thus may help in understanding its necessities.

5.3.1 Database on LAC power plants (part of SIEE)

In the power plant database 1,295 power plants are recorded according to the following data:

- **Country**
- **Name of plant**
- **Location of power plant**
- **Operating company**
- Owner of plant
- **Year of commissioning**
- Reference year of data update
- **Status of activity**
  - decommissioned
  - operating
  - under construction
- **Type of Plant**
  - Combined Cycle Gas Turbine
  - Diesel engine
  - Fluidised Bed
  - Gas turbine
  - Geothermal
  - Nuclear
  - Steam turbine
- **Nominal Power [MW]**
- Effective Power [MW]
- Power generation per year [GWh]

- ➢ Load factor of plant [%]
- ➢ US$/kW Investment
- ➢ **Type of fuel for power generation**
    - Biomass (biogas, bagasse)
    - Black liquor
    - Coal
    - Diesel
    - Fuel oil
    - Gas (e.g. from blast furnace)
    - Natural Gas
    - Steam (from geothermal sources)
    - Uranium
- ➢ Thermal efficiency of plant [%]

Most entries have been found in the data categories given in bold letters. Especially data taken from the categories country, year of commissioning, type of plant, nominal power and type of fuel have served for the evaluation in the following chapters.

5.3.2 Survey of the size of power plants

The number of power plants in the countries varies significantly (see figure below). Brazil has registered 738 power plants in the database which accounts roughly for 60% of the total registered plants. However, 90% of those plants are below 50 MW power output.

Regarding the installed capacities of the power plants in the region it can be recognised that 73% of the plants have nominal power outputs <50 MW. In the range of 100 to <400 MW 23% of the plants can be found and 4% of the plants have power outputs in the range between 400 and <1000 MW. There are 9 power plants with power outputs between 1 and 2 GW and only 4 power plants show a nominal power output of more than 2 GW. Two plants of those operate in Mexico (type: both steam turbine fired with fuel oil) and the other two in Venezuela (type: one steam turbine and one gas turbine, both fired with natural gas).

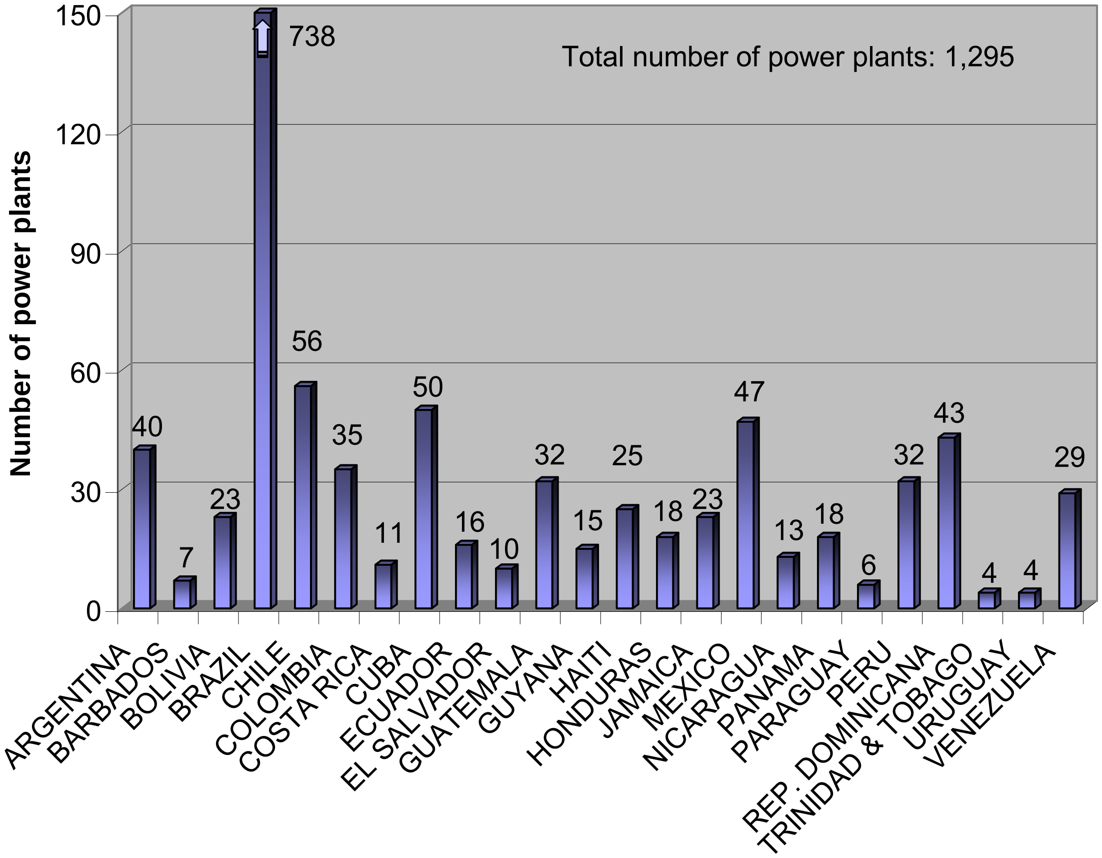


Figure: Number of power plants per LAC country registered in the power plant database, 2004 (source: OLADE)

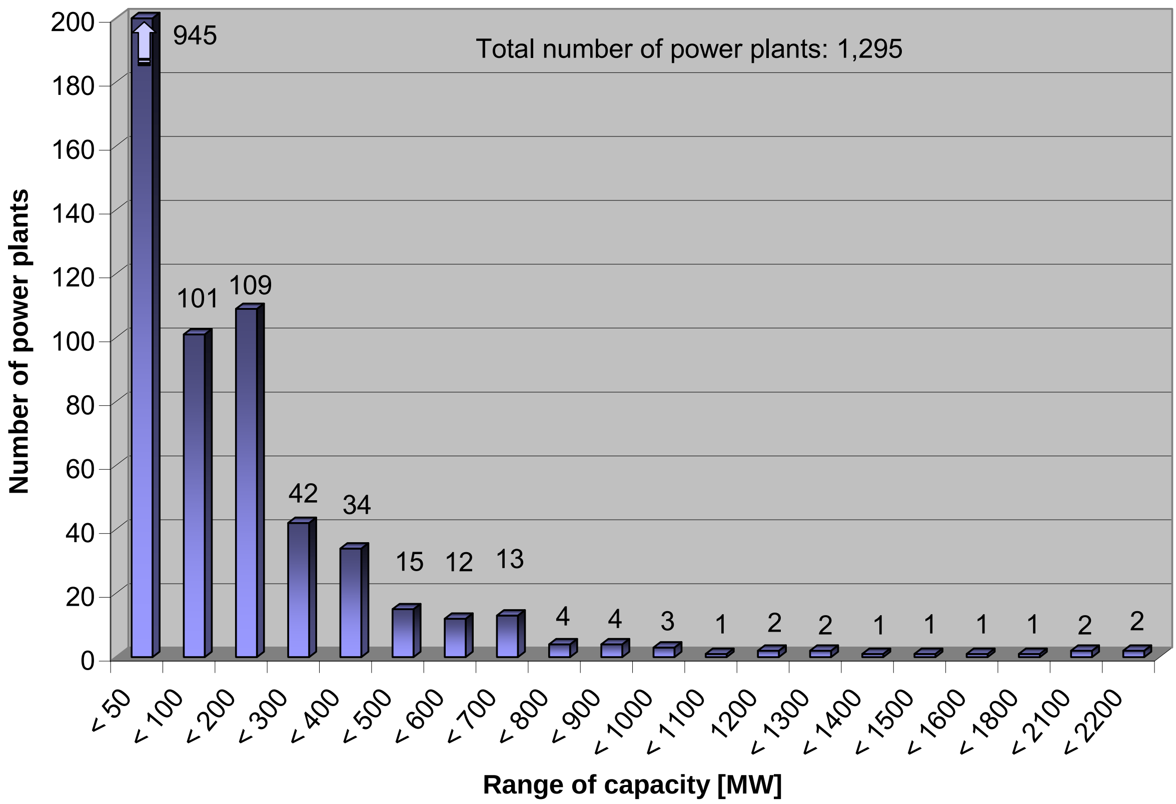


Figure: Capacity range of power plants in LAC acc. to power plant database, 2004 (source: OLADE)

5.3.3 Types of power plants in operation

In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam and gas turbines (see figure below). Since the 1980s natural gas combined cycle plants and - using renewable energies - also geothermal power plants have been constructed and commissioned. In addition to the gap of information about 17 GW of installed power (see para 5.3, p.77) there is unfortunately no information available about the types of the 738 Brazilian power plants which account for ca. 25 GW power capacity in total.

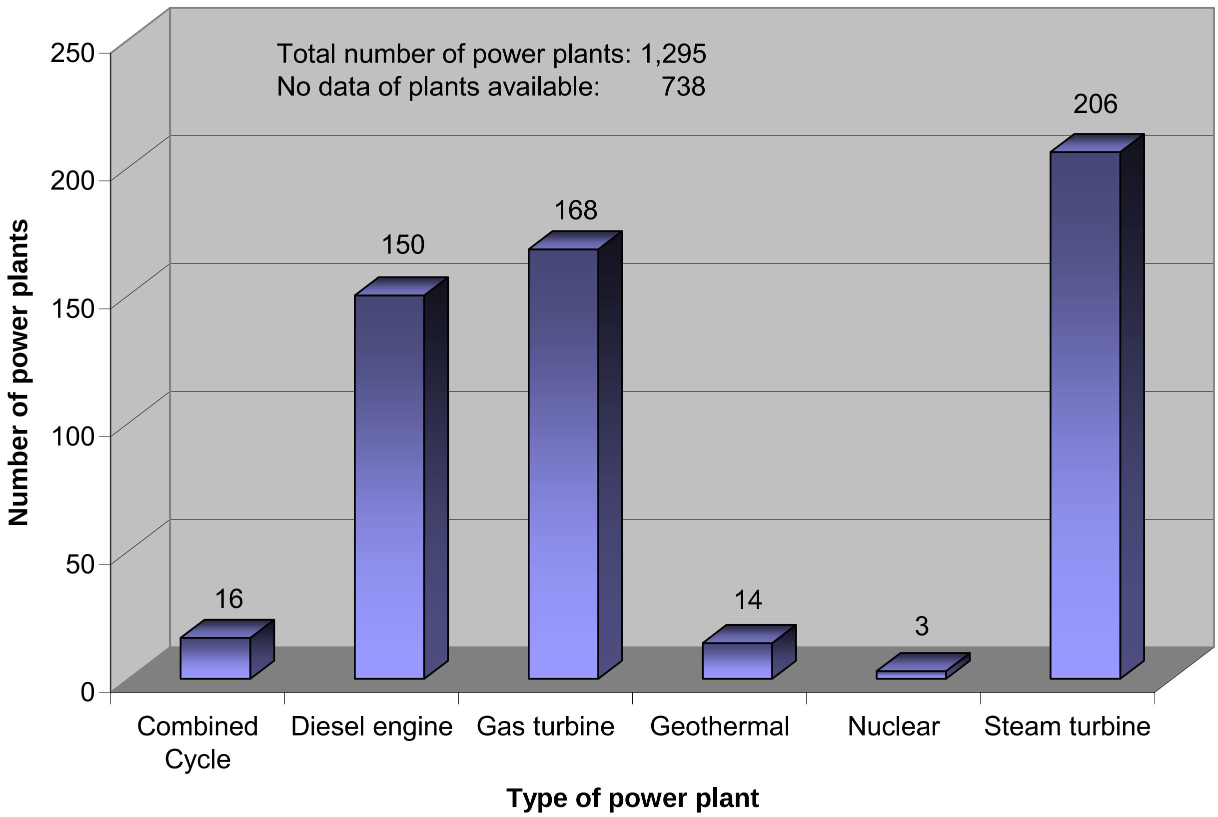


Figure: Number of different power plant types in LAC acc. to power plant database, 2004 (source: OLADE)

Considering, however, the amount of installed power capacities it becomes obvious that the diesel engines, although as numerous as the gas turbine power plants, provide only 6% of the overall power production (see figure below). Gas turbines account for 27% and steam turbines for 56% of the power generation. Gas combined cycle plants contribute 7% to the power generation. The balance of 4% is made up by geothermal and nuclear power plants.

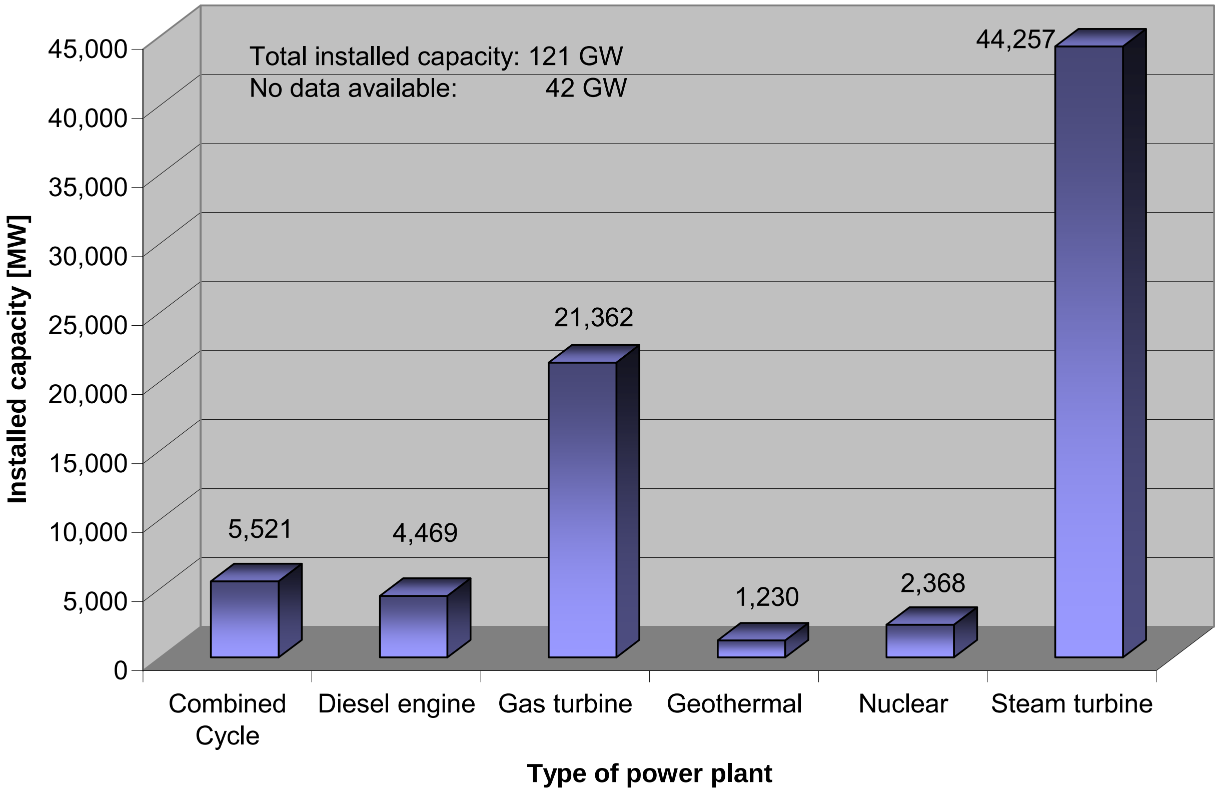


Figure: Installed capacity of different power plant types in LAC acc. to power plant database, 2004 (source: OLADE)

5.3.4 Fuels for power generation

The variety of fuels used in the power plants comprises biomass (biogas, bagasse), black liquor, coal, diesel, fuel oil, gas (e.g. from blast furnace), natural gas as well as steam (from geothermal sources) and Uranium. Regarding the number of power plants it becomes evident (see figure overleaf) that most plants operate on (in descending order) diesel, biomass, natural gas and fuel oil.

As most diesel engines and biomass plants represent power plants of lower capacity, the power generation by fuel has to be highlighted in order to get a feeling for the importance of a certain type of fuel. The figure overleaf shows that natural gas (50%) contributes most to the power generation, followed by fuel oil (25%), diesel (10%) and coal (7%). Biomass has only a share of 3% (similar to the nuclear power generation), despite the high number of plants in operation (mainly from Brazil).

It is not surprising that about 85% of the power generation is based on oil and natural gas while the region is rich of oil and gas reserves. The fossil fuel coal actually plays no major role in the LAC power sector although large reserves are present in the region. Coal is dedicated mostly for exports to Europe and the United States. Nevertheless, some coal fired power plants (pulverised fuel, conventional steam cycle) can be found in Colombia, Chile, Brazil, Dominican Republic and Mexico.

Co-combustion of coal and biomass actually is of minor importance as there are only a few coal fired power plants available in the region. Co-combustion may gain importance when the number of coal fired plants will increase in the medium to long term future.

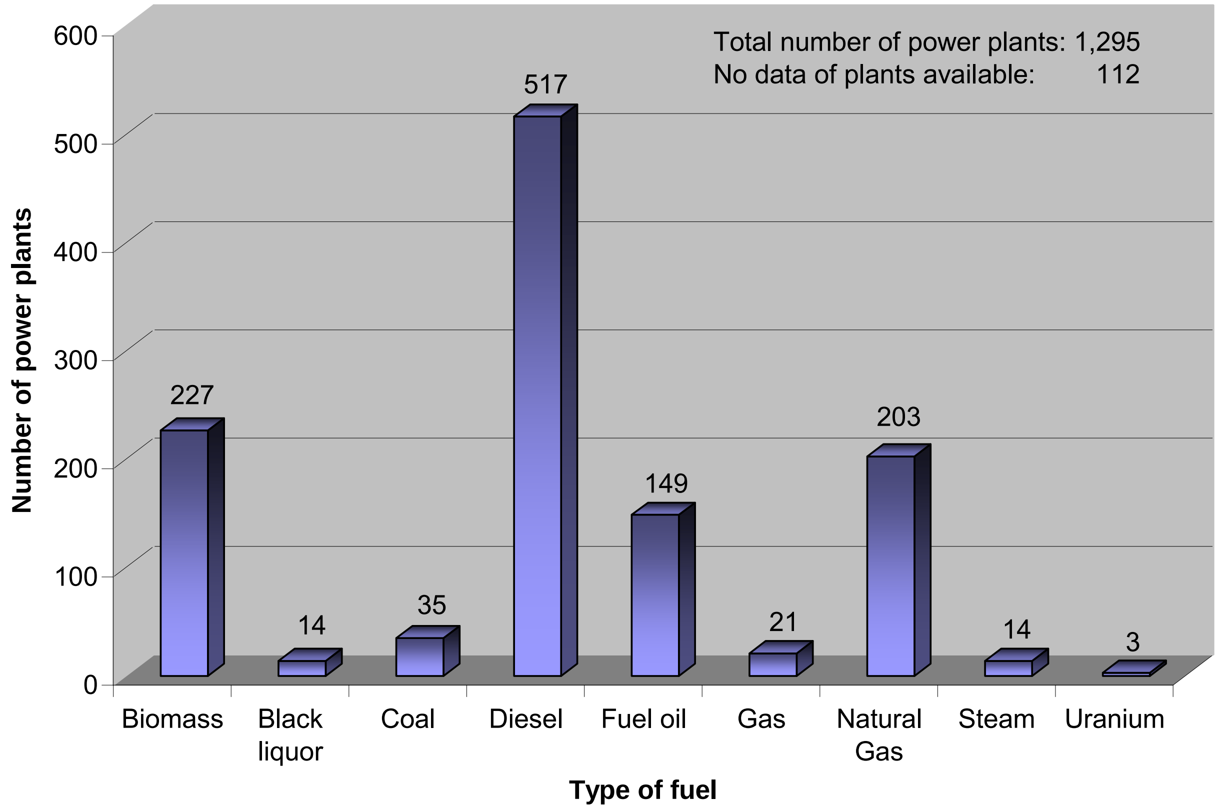


Figure: Fuels used in LAC power plants acc. to power plant database, 2004 (source: OLADE)

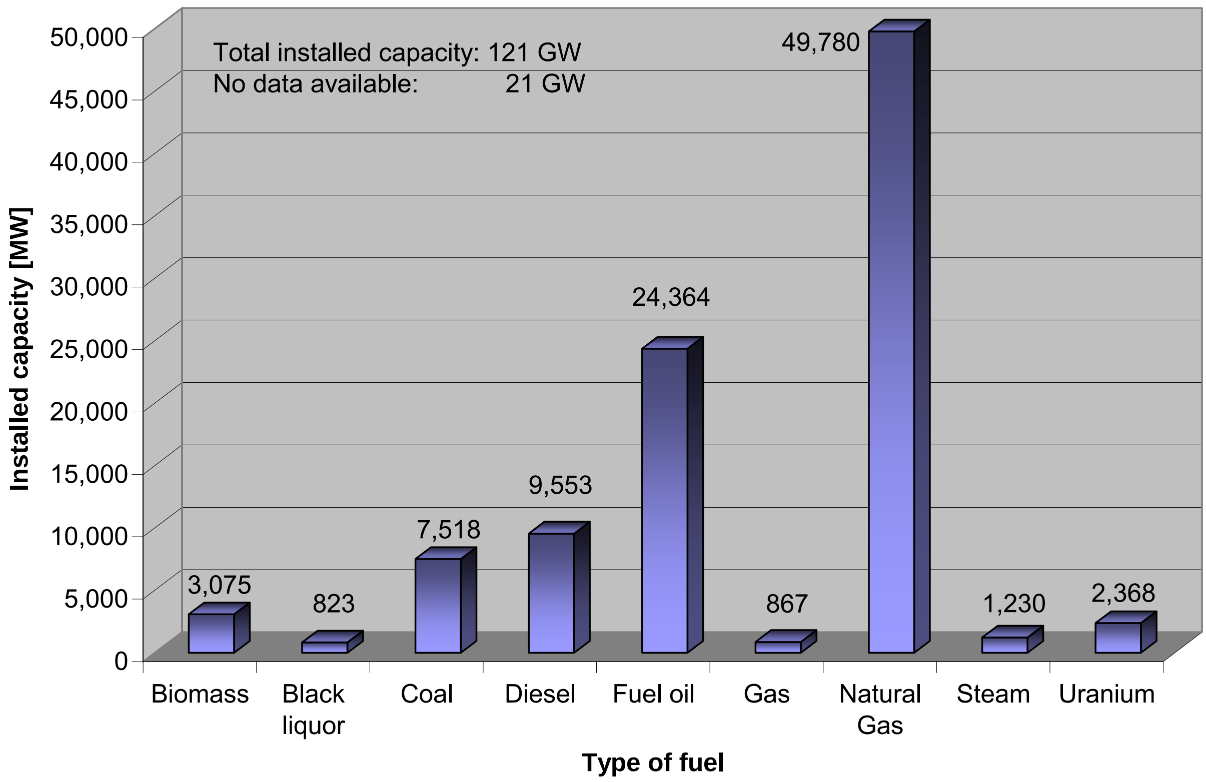


Figure: Contribution of different fuels to power production in LAC acc. to power plant database, 2004 (source: OLADE)

In the following figure (below) the installed capacities of the different types of power plants are compared, however, this time under consideration of the fuel used. Combined cycle plants are using mostly natural gas; only a minor number of plants uses also fuel oil. Diesel engines run on both diesel and fuel oil. As a speciality, there is one diesel engine also operating with biogas in El Salvador. The gas turbine power plants use natural gas at a high share, but also some facilities are running on fuel oil and diesel. The power plants operating with steam turbines mainly burn natural gas and fuel oil. To a minor extent coal is used at feedstock. There are even some steam turbine plants operating on diesel.

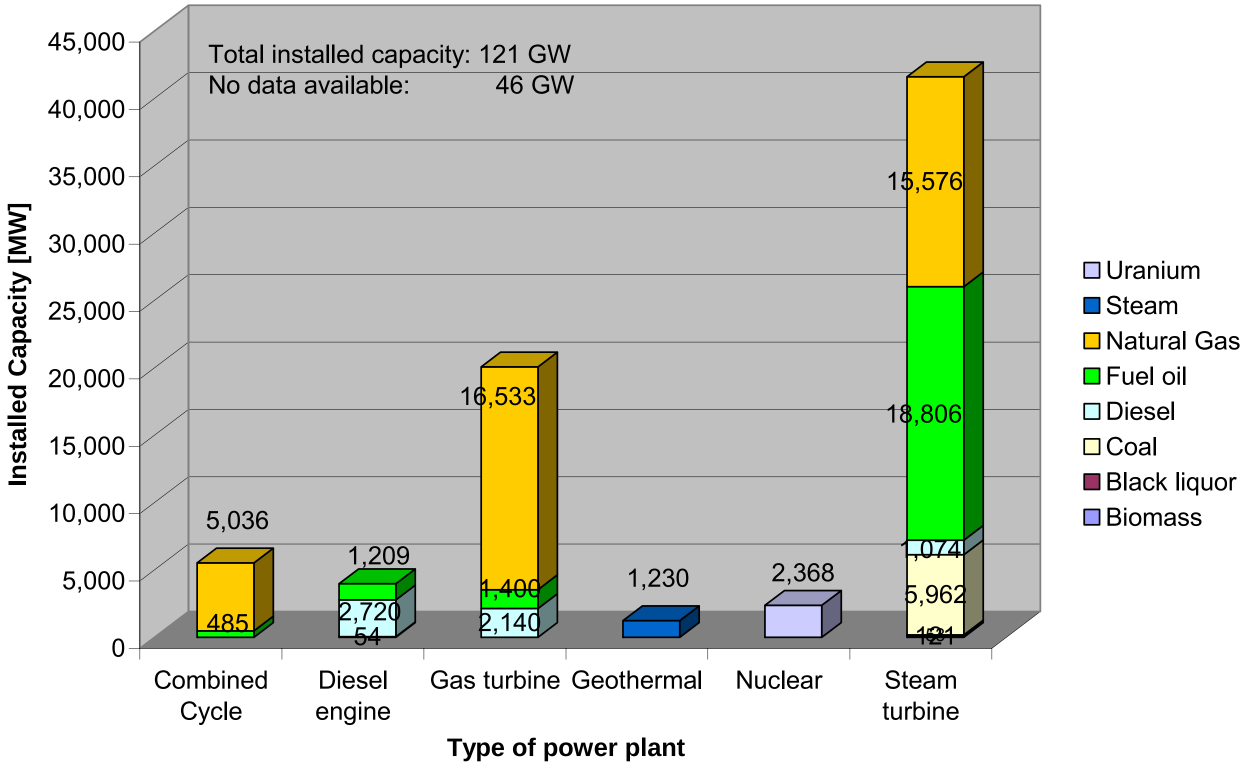


Figure: Fuel feed to different types of power plants acc. to power plant database, 2004 (source: OLADE)

5.3.5 Age of the power plants

The figure overleaf shows the decade of power plant commissioning and summarises the installed capacities per decade.

The main development of the power market commenced in the 1960s and increased through the 1970s. However, a remarkably decrease of new capacities can be detected in the 1980s. In the 1990s again considerable capacities have been installed contributing to the overall increase of generating capacities in LAC. In the decade < 2010 obviously only 4 years have passed and 6 years are to come where the power plant capacities will further increase.

In the period until the end of the 1960s mainly steam turbine power plants have been constructed (see figure overleaf). Since the 1970s gas turbines became a main competitor to steam turbines for large scale power generation. Also since the 1970s an increasing number of diesel engines can be recognised in the LAC power market taking care of decentralised power supply in remote areas.

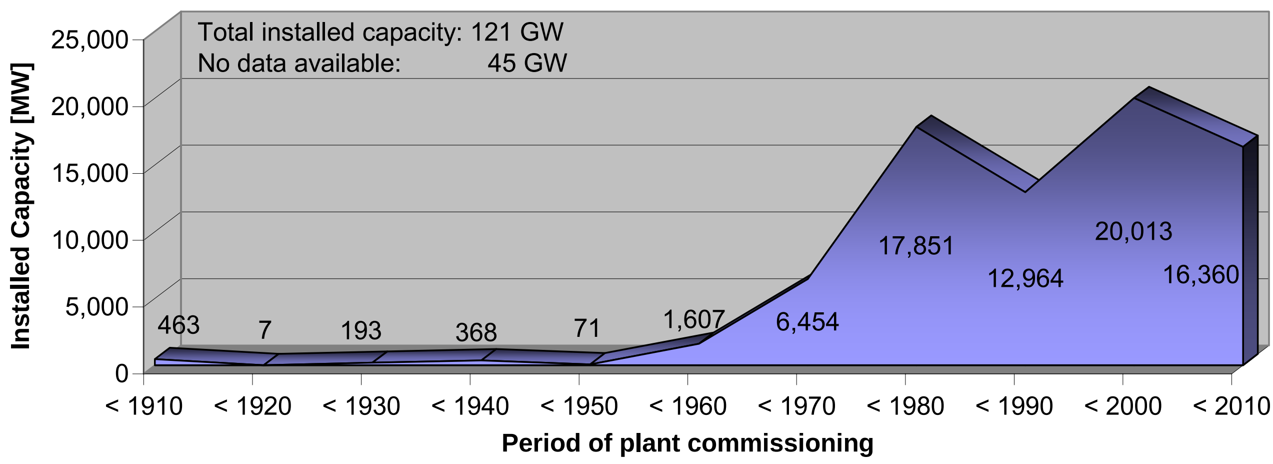


Figure: Installed capacity and period of plant commissioning acc. to power plant database, 2004 (source: OLADE)

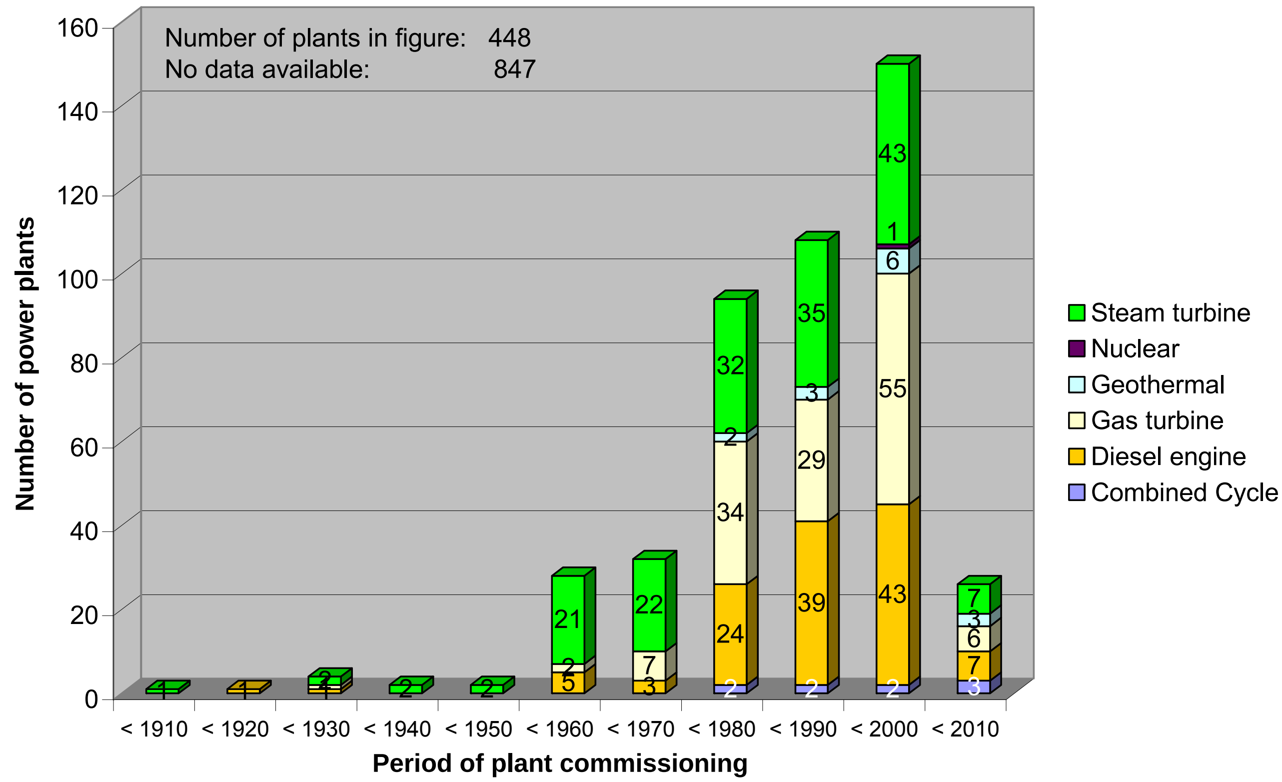


Figure: Periods of commissioning of different power plants acc. to power plant database, 2004 (source: OLADE)

Taking a possible replacement of the installed capacities after 30 years of operation into account a potential can be calculated which is actually in the order of 9 GW (7%) of the actually installed capacities, but will rise in the coming decade. Moreover, the LAC power market is growing at a rate of 4-5 % p.a. (i.e. some 12 GW p.a.).

5.3.6 Emission reduction from power plants

Actually there is no legislation in place that regulates emission output of power plants of any size. Hence, most commonly there are no emission reduction facilities installed at the operating power plants in LAC.

6 EU CFT technologies – options for the LAC power market

Key findings:

- Adequate EU CFT technologies for large scale power generation corresponding to the LAC power market needs comprise gas and steam turbine plants as well as combined-cycle plants running on natural gas.
- Options for the longer term (>20 years) include pulverised coal combustion and IGCC plants – for the time when the oil and gas reserves of the region start to deplete.
- For small-to medium-power outputs (up to approximately 30 MW), a diesel generator power plant can be a genuine alternative. The high efficiency of modern diesel engines is slightly less than combined-cycle with the same rating.
- Whenever gas or oil is fired in a power station, the combined-cycle plant is more economical than the steam power plant due to its higher efficiency and lower specific price. Modern combined-cycle plants are simpler, less expensive, and operationally more flexible than steam power plants.
- For short utilization periods (peaking units), the gas turbine is most economical. Gas turbines can serve as intermediate - or base-load units in countries where fuel is abundant at low cost. The lack of water consumption has made this machine popular in dry regions. The short installation time allows a customer to plan a new installation on short notice.
- If all fuels are readily available at world market prices, gas fired combined-cycle plants are the most economical solution for intermediate- and base-load applications. This results in a limited environmental impact (small heat rejection or low water consumption). With clean fuels like natural gas, this technology also achieves lowest emissions.
- EU technologies offer retrofit options for emission reduction either by modifications of the burner design (low-NOx), the process design (air staging, reburning), plant control systems or by end-of-pipe pollution abatement and control technologies (e.g. filters, scrubbers, etc.).

According to the findings about the LAC power market (see chapter 5) natural gas and oil are the main fuels used for fossil fuel power generation. Coal actually plays only a minor role.

Corresponding to the recent requirements of the LAC power sector this chapter will focus on available state-of-the-art EU technologies for large scale power generation from oil and gas, i.e.:

- Gas Turbine Power Plant
- Combined Cycle Gas Turbine (CCGT) Power Plant
- Steam Turbine Power Plant

Nevertheless, as projections of the future oil and gas demand indicate a depletion of the resources in the region at less than 30 years coal may gain an increasingly importance in the LAC power sector. Therefore also two options of power generation from coal will be taken into consideration, i.e.:

- Pulverised Fuel Combustion

- Integrated Gasification and Combustion of Coal (IGCC)

6.1 Gas / oil fired gas turbine power plants

6.1.1 Gas turbines characteristics

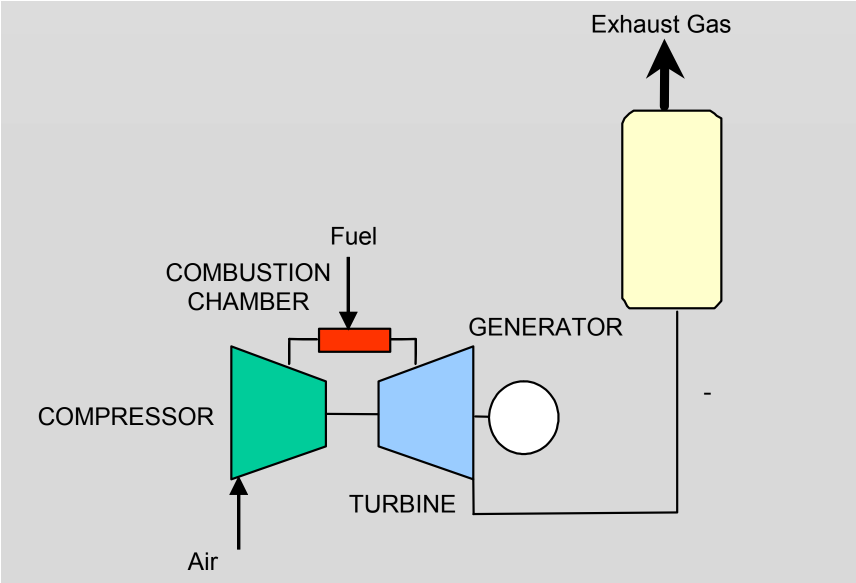
Gas turbines can be divided into three main types:

- Heavy-duty industrial gas turbines (GTs) which are considered conventional in design, the firing temperatures and cycle efficiency of these units are conservative by modern standards and this is reflected in the design and choice of materials throughout the GT. These units range in output from 15 to 170 MW and yield an open cycle efficiency of approximately 29 to 34 per cent. These conventional design units are noted for being very reliable machines and they have accumulated considerable operating hours.
- Heavy-duty industrial GTs which are considered “state of the art”: The firing temperatures, compression ratios, combustion systems, cooling and sealing systems, material selection, manufacturing processes and blading designs in these machines are considered in many cases to be “state of the art”. In general, these units fall into two main output bands in simple cycle 50 Hz configuration: 60 to 70 MW and 250 to 270 MW. The open cycle efficiency figures range from about 34 to 38 per cent.
- Aero-derivative GTs: These GTs as the term suggests are land-based derivatives of successful aero-engine designs. Aero-derivative units are characterised by high open cycle efficiency figures and short start-up times, compared with heavy-duty industrial GTs. The largest aero-derivative GTs are in the region of 45 to 50 MW, going down to 2 to 3 MW at the low end of the range. Typically open cycle efficiencies in the 25 to 50 MW output band are in the range 38 to 42 per cent.

All three types of gas turbines can be used in open-cycle (OCGT) or combined-cycle (CCGT) configuration, which are in more detail described in Annex 7.

6.1.2 Gas fired turbines

The term "gas turbine" is most often used as an abbreviation for a gas-turbine engine, which is a heat engine that accepts and rejects heat and produces work. The input heat is usually in the form of fuel that is burned (giving rise to the term “combustion turbine”), but may also come from another process via a heat exchanger. The rejected heat is usually in the form of hot engine-exhaust flow released to the atmosphere, but may also be rejected to another process via heat exchanger. The work may be given as output torque in a turning shaft or as the velocity and pressure energy in a jet, which would produce thrust on a moving airplane. The term “gas turbine” can also be used more narrowly for just the turbine expander in a gas-turbine engine.



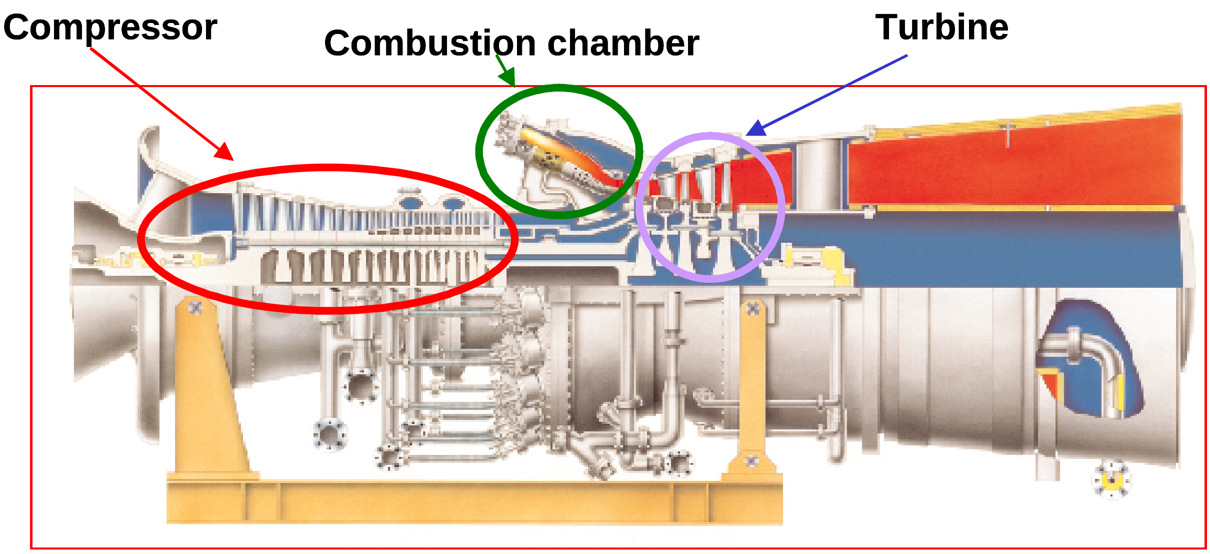


Figure: Simple gas turbine cycle

Therefore, the gas turbine is typically an internal combustion rotary engine, the most widely known example of which is the jet aircraft engine. Basically, the engine burns a lean mixture of fuel with compressed air. The hot pressurized combustion gases expand through a series of rotating turbine wheel and blade assemblies resulting in shaft power output, propulsive thrust, or a combination of the two. Today the gas turbine engine is a widely used source of propulsive thrust and mechanical power.

The basic gas turbine engine consists of a compressor, a combustor, and a turbine in series. The basic cycle is illustrated in the figure given above. The intake air is compressed and delivered to the combustor at substantially increased pressure and temperature. There, the fuel is burned and the temperature raised to a higher value (beyond of 1100 °C during continuous operation). These high pressure/high temperature combustion gases then expand through the turbine, causing it to rotate. The turbine drives the compressor and any excess energy available produces shaft power, thrust, or a combination of both. Every gas turbine engine operates on some variation of this cycle.

The number of stages or configuration can change, but there is always compression followed by heating followed by expansion of the working fluid (air in this case).

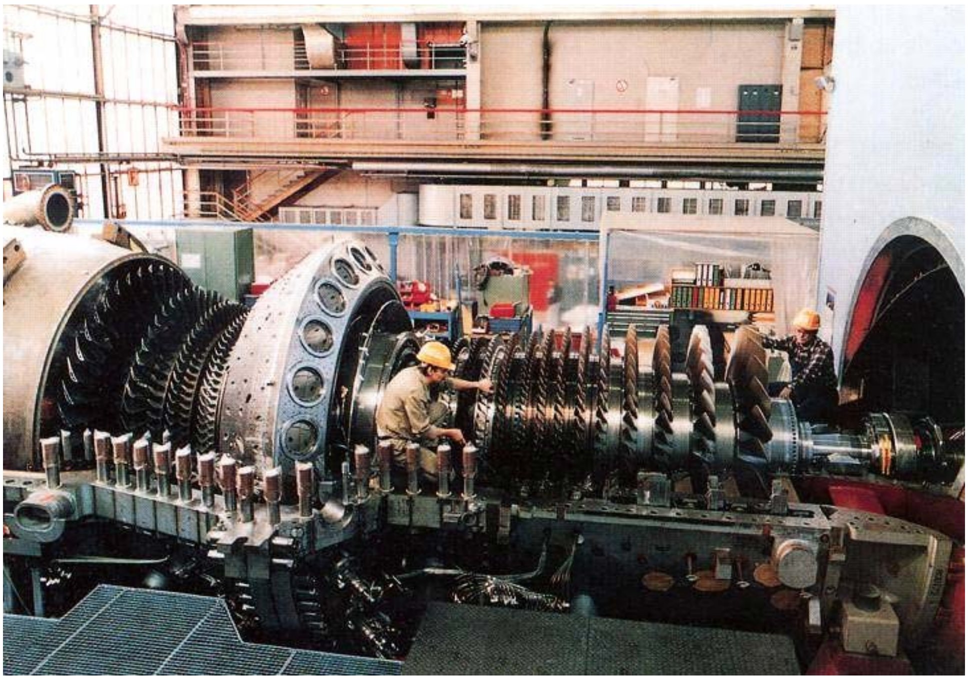


Figure: Gas turbine assembly (photo: courtesy of Alstom)

It is important to realize that in the gas turbine the process of compression, combustion and expansion do not occur in a single component as they do in a reciprocating engine. They occur in components which are separate in the sense that they can be designed, tested and developed individually, and these components can be linked together to form a gas turbine unit in a variety of ways (see figure above). The possible number of components is not limited to the three already mentioned. Other compressors and turbines can be added, with intercoolers between the compressors, and reheat combustion chambers between the turbines. A heat exchanger which uses some of the energy in the turbine exhaust gas to preheat the air entering the combustion chamber may also be introduced. These refinements may be used to increase the power output and efficiency of the plant at the expense of added complexity, weight and cost. The way in which these components are linked together not only affects the maximum overall thermal efficiency, but also the variation of efficiency with power output and of output torque with rotational speed. One arrangement may be suitable for driving an alternator under varying load at constant speed, while another may be more suitable for driving a ship's propeller where the power varies as the cube of the speed.

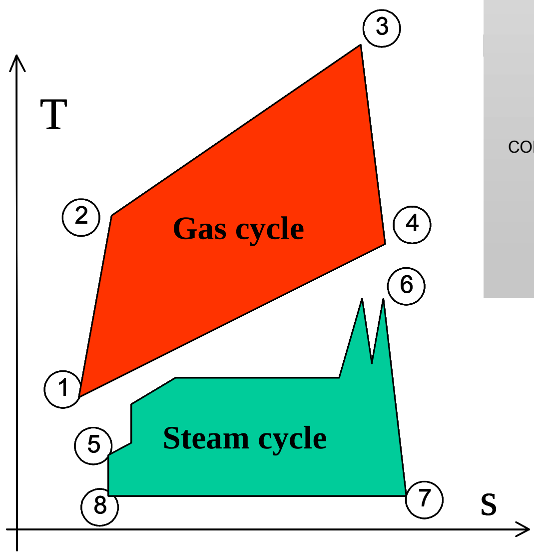
Apart from variations of the simple cycle obtained by the addition of these other components, consideration must be given to two systems distinguished by the use of open and closed cycles.

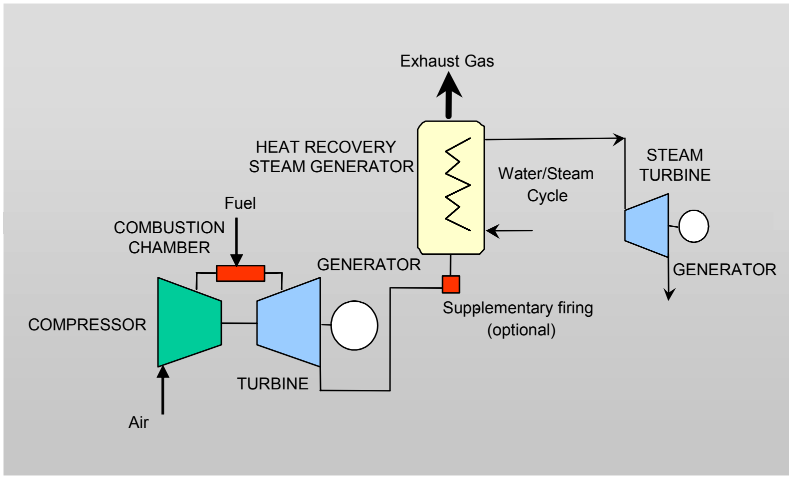
6.1.3 Combined-cycle gas turbines (CCGT)

The previous explanations of the gas turbine process clearly showed that the exhaust gas still leaves the turbine with a high temperature. In the case of an improvement of the simple cycle, this heat potential can be partly utilized by means of recuperative heat exchange (HRSG – Heat Recovery Steam Generator).

This heat potential can be used even more efficiently, if the gas turbine is combined with other plants. A steam process is connected to the gas turbine process in order to achieve an increase in power and efficiency, because the exhaust gas temperature of present gas turbines is higher than the turbine inlet temperature of a steam process. In order to meet the demand for heat, the heat contained in the exhaust gas can be exchanged to a district heating network in a waste-heat boiler

The advantage of the gas turbine process lies in the heat supplied at a high temperature level. The high exhaust gas temperature is disadvantageous. The turbine inlet temperature of the steam process is limited by the material technology and has a relatively low temperature level. The extraction of the heat at a low temperature level is advantageous. Combining both processes, the advantages of each can be used.





1-2	Compressor
2-3	Combustion chamber
3-4	Turbine
5-6	Heat Recovery Steam Generator
6-7	Steam Turbine
7-8	Condenser

Figure: Heat exchange of a combined cycle

The description of the combination of a gas and steam turbine in a T,S-diagram (see figure above) shows the transfer of heat contained in the gas turbine´s exhaust gas to the steam cycle by a heat exchanger. This results in the heating up of the water in the steam cycle followed by evaporation and superheating of the steam. Therefore, a required minimum temperature difference between the exhaust gas and the steam must be maintained. In general this state exists at the boiling point of water. The super-heated steam expands in the steam turbine.

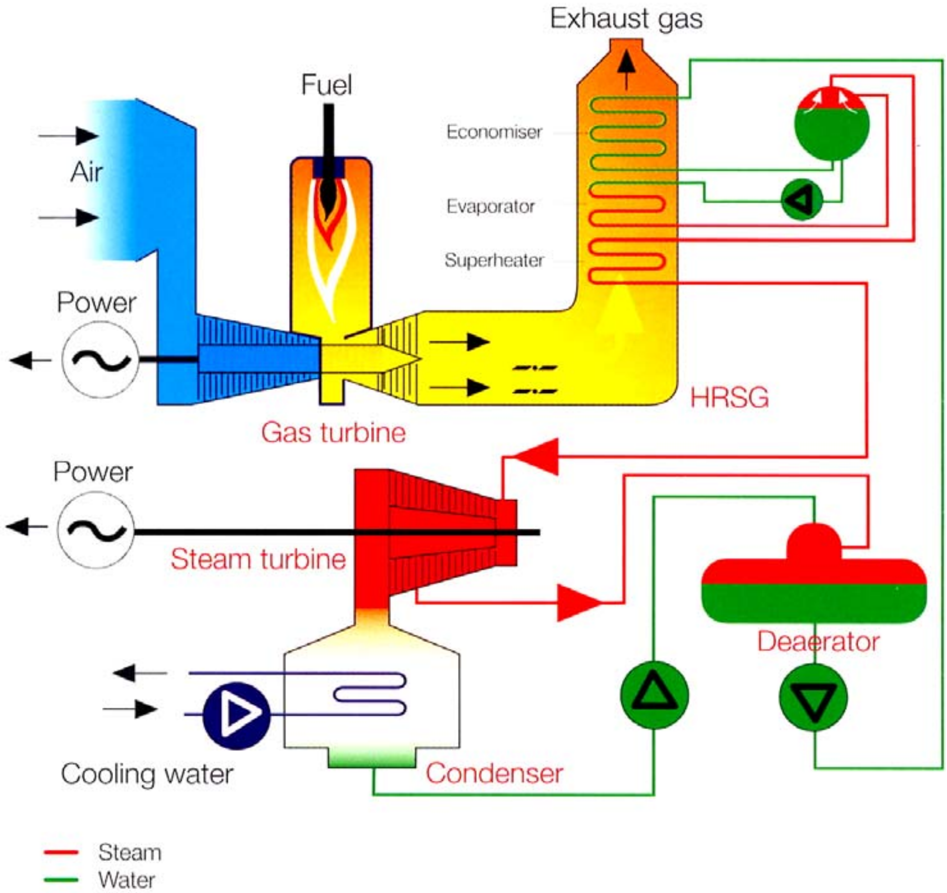


Figure: Combined Cycle Power Plant

The rise in power and efficiency achieved by combining both processes is based on the additional effective power available through the steam turbine process.

The schematic description of this combined gas and steam turbine process is shown in the figures given above. The gas turbine process consisting of a compressor, a combustion chamber and a turbine is combined with a waste-heat boiler used as a heat exchanger in which the water is transformed into steam by a pre-heater, an evaporator, and a superheater. The steam flows through the turbine and is condensed to water in a condenser. This combination of processes is the most efficient of all thermal power plants.

A rise in the effective power of the total cycle can be achieved by heating the exhaust gas of the gas turbine by means of a supplementary firing. In the heat exchange with the steam process the exhaust gas is available at a higher temperature with the result that the turbine inlet temperature can be increased. Consequently the steam turbine delivers more power than a steam turbine operating in the unfired process.

6.1.3.1 Emission control from gas-fired turbines and combined cycles

Abatement of dust emissions

Fuel dust contained in natural gas is washed out at the production site if necessary. Dust or particulate matter emissions from gas turbines burning natural gas are not an environmental concern under normal operation and controlled combustion conditions.

Other gases, such as the by-products of chemical plants, can contain dust. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with primary and secondary measures to reduce the dust emissions if these limits cannot be met.

Abatement of SO_2 emissions

Fuel sulphur in natural gas in the form of H_2S is washed out at the production site. Thus, fuel qualities are obtained which directly meet SO_2 emission limit values for all applications. Other gases, e.g. as by-products of chemical plants, can contain sulphur. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with FGD technology if these limits cannot be met.

Abatement of NOx emissions - Water or steam injection

Since dry low-NOx combustors (DLN) have reached an acceptable state of development, water/steam injection has become used in Europe, although only to a minor degree so far, as a NOx reduction measure. However, for existing installations, it is the most easily applicable technology, and may be applied in combination with other NOx abatement measures. In Canada, about half of the gas turbines with NOx control are equipped with steam/water injection.

Water/steam injection can be performed either by the injection of a mixture of fuel and water or steam or by the injection of water or steam through nozzles directly into the combustion chamber. The evaporation or superheating of steam requires thermal energy, which is then not available to heat the flame. Thus, the flame temperature decreases and NOx formation also reduces. The emission reduction rate strongly depends on the amount of water or steam used. In order to reach high emission reduction rates, large amounts of water or steam are necessary. Sometimes the amount of water or steam injected is higher than the amount of fuel burned. A higher emission reduction rate can be achieved with water than with steam (for a given water or steam-to-fuel ratio), which can be explained by the fact that more energy is required to evaporate the water (in practice approximately twice as much steam is necessary to achieve the same NOx emission reduction). Water injection is often used when steam is not available, e.g. in simple cycle applications and in pipeline compression, whereas steam injection is usually preferred on natural gas fired combined cycles, where steam is readily available from the exhaust heat recovery system.

The steam, or water, injected into gas turbines needs to be of very high purity, which requires the use of high quality water treatment plant, which in turn may create a liquid effluent requiring disposal. Also, the steam or water needs to be injected at high pressures, usually 20 bar or greater. The use of steam or water injection may also reduce the life expectancy of a gas turbine.

Emission reduction rates between 60 and 80 % can be achieved but without limiting CO. If CO emission limit values are observed, NOx reduction rates between 40 and 60 % can be achieved. The steam/water to fuel ratio depends on the gas turbine type (e.g. for flame) and it varies between 1 to 1.2. NOx emissions can be reduced to approximately 80 – 120 mg/Nm3 (at 15 % O2).

The injection of water or steam has an influence on the general gas turbine parameters, such as the output, efficiency, and the exhaust mass flow. For example: the efficiency of a gas turbine is reduced through water/steam injection, and flame stability problems can be observed at high water-to-fuel ratios.

The investment costs for retrofitting gas turbines with water or steam injection can vary widely. They are mainly related to the water conditioning and injection devices used. The additional operating costs incurred by the water/steam injection are due to an increased fuel consumption.

Some major drawbacks of this NOx abatement technique are the increased emissions of CO and hydrocarbons, a decrease in the thermal efficiency of the installation, and an increase in fuel consumption. Steam injection causes a greater efficiency loss than water injection (3 – 4 % for water injection). Furthermore, direct injection of water or steam results in a higher material stress (small fissures can occur on the material surface due to temperature shock) than injection of a fuel/water or steam mixture. As a consequence, the latter alternative is preferred.

The emission levels can vary a lot, depending on the load of the turbine. In many installations, the steam can be produced only in higher loads, which means that emissions will be reduced only after this base load level has been reached. This makes steam injection of little use for gas turbines with lots of load changes. A steam injection retrofit for a 140 MWth gas turbine costs about € 1.7 million.

Abatement of NOx emissions - Dry Low-NOx (DLN) technologies

Currently, dry low-NOx combustors are applied for large gas turbines, and seem to be becoming more widespread in small facilities (e.g. gas turbines with capacities even below 20 MWe). DLN technology has recently also been applied to gas turbines operated offshore.

The basic characteristic of dry low-NOx combustors is that the mixing of the air and fuel and the combustion take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature are achieved, resulting in lower NOx emissions. Currently, dry low-NOx combustors represent a well-established technology, especially for gas turbines using natural gas.

Dry low-NOx combustion systems are very effective and reliable. Today, almost all gas turbines in industrial use are equipped with dry low-NOx systems. Modern dry low-NOx burner retrofits cost appr. € 2 million for a 140 MWth gas turbine. Due to their high efficiency, new burners are very economical to operate, especially as there are no big losses of energy from fuel losses, or in the form of hydrocarbons etc.

Selective Catalytic Reduction (SCR)

Many gas turbines currently use only primary measures to reduce NOx emissions, but SCR systems have been installed at some gas turbines in Austria, Japan, the Netherlands and in the US (especially in California). It is estimated that approximately 300 gas turbines word-wide are equipped with SCR systems.

6.1.4 Oil fired gas turbines

Gas turbines fuelled with liquid fuels as the main fuel (not as the back-up fuel) are very rarely applied in Europe, due to the extensively high costs of such fuels, mainly light distillate oil; and the stress imposed by liquid fuels on gas turbine blades and rest systems compared to natural gas. Therefore, applications are very rare and only exist in those cases where a natural gas supply does not exist. Two types of liquid-fuel-fired gas turbines are currently applied: heavy-duty gas turbines and gas turbines derived from aeroplane engines, so-called aeroderivatives.

By means of an axial compressor, pressurised air is driven into the combustion chambers, where the fuel injectors are connected. During the combustion reaction, the gas temperature rises, and at between 1000 °C and 1350 °C it is introduced into the turbine. These hot gases are depressurised in the turbine, which simultaneously drives both the air compressor and the alternator, which in turn generates electricity. In the “open cycle” configuration, the combustion gases are released directly into the atmosphere at a temperature of >450 °C. The thermal efficiency is then between 30 and 40 %.

Gas turbines (GT) can operate with a wide range of liquid fuels, such as residual fuel naphtha. Gas turbines in general and aeroderivatives in particular run on light distillate fuel oil or on kerosene. For recent designs of turbines, which have high turbine inlet temperatures, the manufacturers' specifications for fuel supplies are very stringent. They stipulate the physical and chemical properties needed in order to meet both the equipment demands and the environmental standards, particularly with regard to metal contaminants (sodium, potassium, lead, vanadium, calcium), sulphur and ashes.

6.1.4.1 Emission control from oil fired turbines

Abatement of SO_2 emissions

Switching to low-sulphur oil can make a significant contribution to SO_2 emissions reduction. The sulphur content of light fuel oil used in gas turbines is determined by the relevant Directive 93/12/EEC (relating to the sulphur content of certain liquid fuels valid in the EU), and should be below 0.05 %. This very low sulphur content ensures low emissions levels of SO_2 from gas turbines fuelled by light distillate oil.

Abatement of NOx emissions

NOx formation can be restricted by decreasing the combustion temperature. This is accomplished by the pre-mix burner technique, where fuel is blended with the combustion air in order to avoid excessive peak flame temperatures. This, however, only operates when the unit is operating near full load. A different combustion method must be applied for part-load operation, start-up and shutdown, in order to avoid flashbacks. Steam injection and water injection are also used to reduce combustion temperatures and consequently NOx.

Applying stage combustion in gas turbines at lower temperatures needs a different design of gas turbines as two pressure stages with separate fuel supply are needed.

Wet reduction processes: Water or steam is injected into the combustion chambers in order to reduce the combustion temperature, thus avoiding the formation of thermal NOx. For gas turbines

(GT) operating in the "open cycle" system, water is used for injection, whereas for GTs operating in a "combined cycle" or cogeneration system, steam is more often chosen for the injection.

Some gas turbine combined cycle plants in Europe, particularly in Austria, France, Germany, Italy, and the Netherlands, have also applied SCR systems to reduce NOx emissions.

6.2 Gas / oil fired steam turbine power plants

6.2.1 Oil fired steam boilers

Boilers designed for burning liquid fuels such as heavy fuel oil are very similar to boilers that are used for the combustion of coal. A typical heavy fuel oil boiler is shown in the Figure below.

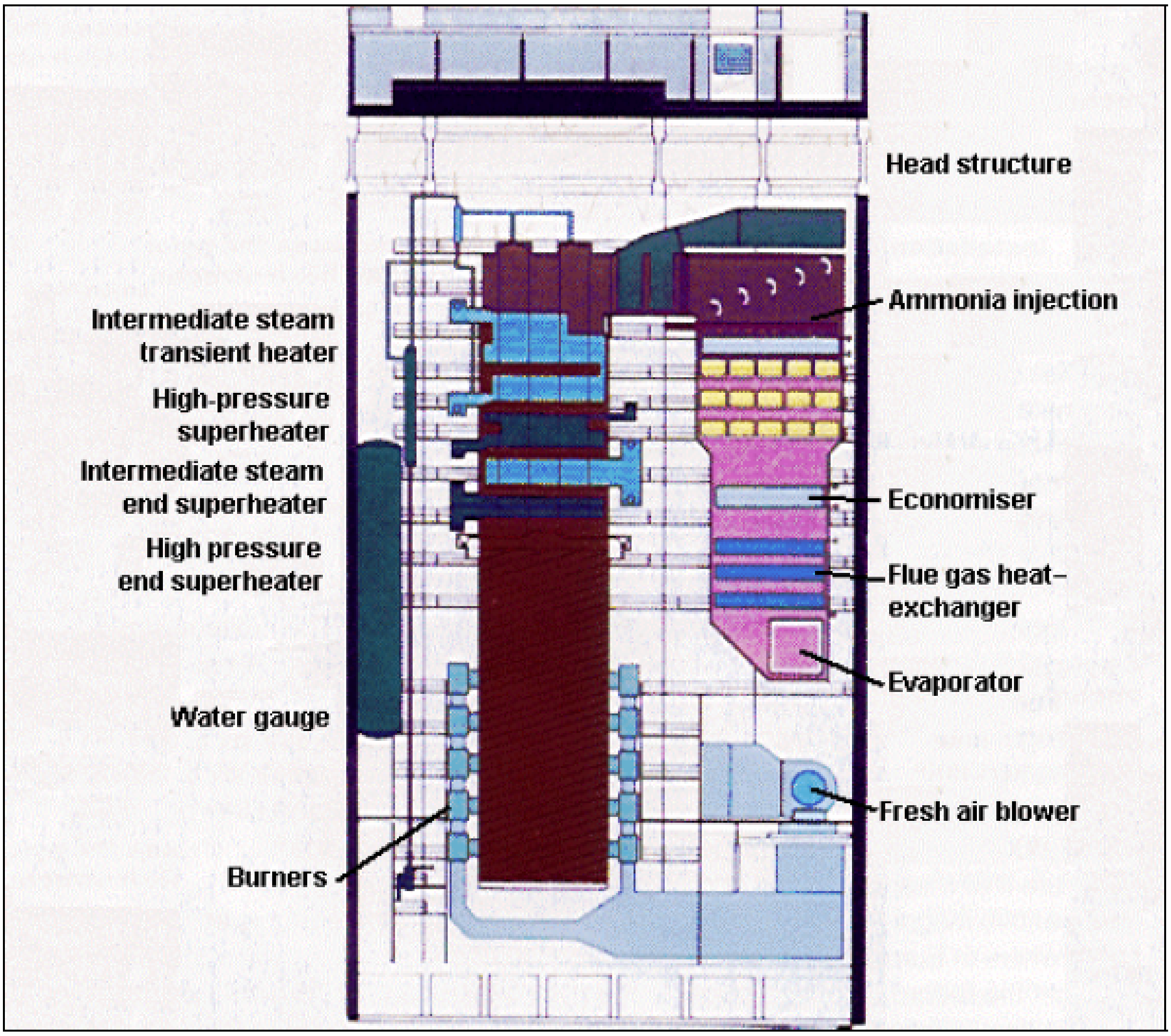


Figure: Sketch of a heavy fuel oil fired boiler

6.2.1.1 Firing systems

The firing systems used in liquid fuel combustion boilers are similar those used in combustion plants where coal is used as a fuel. To achieve a homogeneous combustion, fine aerosol droplets measuring from 30 to 150 µm are sprayed into the boiler by a mechanical process, or through the action of an auxiliary fluid (air or steam) under pressure, or even through a combination of both.

All burner designs are supplied directly with air. When heavy fuel oil is used, low viscosity is needed at the burner, in order to ensure correct atomisation of the fuel. To obtain this viscosity, the heavy fuel oil must be heated to around 120 - 140 ºC. Additives are used to improve the combustion of heavy fuel oil.

Wall- or front-firing systems: In horizontally wall-fired systems the fuel is mixed with combustion air. The burners are located in rows, either on the front wall only or on both the front and rear walls. The latter arrangement is called "opposed firing".

Tangential- or corner-firing systems: The tangentially-fired system is based on the concept of a single flame envelope. Both fuel and combustion air are projected from the vertical furnace corner windboxes along a line tangent to a small circle.

There are three major technical issues that need to be taken into consideration when firing heavy fuels:

- the need for heated storage, transportation and additional heating before atomisation, due to the high viscosity of the HFO
- its tendency to form coke particles
- the formation of corrosive deposits

The first two points are caused by the high molecular weight and the asphaltene nature of some of the constituents. The second and the third points stem from the presence of sulphur, nitrogen, vanadium and other metals in the fuel.

With emulsions, the physical effects of a water addition lead to better combustion properties by improving the atomisation. Micro-explosions are produced as a result of the formation, growth and bursting of vapour bubbles within the superheated droplet. Since the oil can sustain very high temperatures during combustion, the water droplets can be superheated. The emulsion droplet is eventually shattered by the internal formation of water bubbles and their rapid vaporisation. This process is called secondary atomisation, and increases the evaporation surface area and the mixing of the burning species in air. The amounts of particulates and smoke formed are minimised.

6.2.1.2 Control of emissions to air

When using heavy fuel oil (HFO) emissions of NOx and SOx, which lead to air pollution, arise from the sulphur and to a certain extent from the nitrogen contained in the fuel. Particulates originate mainly from the ash content and marginally from heavier fractions of the fuel. The presence of particulates can also lead to higher operational costs, resulting from losses due to the unburned fuel and from deposits in combustion facilities, if the equipment is not well maintained.

Abatement of particulate emissions

Particulate emissions from the combustion of heavy oils may contain two major fractions:

1. Material arising from the organic content of the fuel and its failure to complete the burn-out process:
    - unburned hydrocarbons (smoke)
    - particulates formed via gas phase combustion or pyrolysis (soot)
    - cenospheres produced from cracked fuel or carbon along with ash (coke).
2. Ash from the inorganic content of the fuel:

Smoke may arise from unburned fractions of hydrocarbon fuel exhausted in the form of a fine spray. Such hydrocarbon fractions are the remainders of reactions frozen by thermal quenching. Emissions of unburned hydrocarbons are highest at high equivalence ratios (fuel-rich conditions). Their main environmental effect is their reactions in the atmosphere with NOx and sunlight to form photochemical smog.

Soot is formed in gas-phase reactions of vaporised organic matter in a complex process involving fuel pyrolysis, polymerisation reactions, nucleation, particle growth and burn-out. Fuel droplets burning in envelope flames are subjected to very high temperatures, leading to fuel evaporation and thermal cracking of the large molecular structures, thus resulting in species of higher C/H ratio than the fuel source. Soot is most likely to be formed in fuel-rich conditions, and is normally fully burned as it mixes with air at a very high temperature in highly oxidising zones, e.g. as secondary air is injected into the combustion chamber of a gas turbine.

Coke particulates are formed in liquid-phase processes, and contain all the non-soot carbon and also part of the ash material. Such particles are nearly spherical, hollow and porous, and they range in size from 1 to 100 μm.

Ash fouling and corrosion are major problems when burning heavy oils. Vanadium and sodium are the most harmful elements, respectively forming vanadium pentoxide (V2O5) and sodium sulphate (Na2SO4). Ash deposits jeopardise heat transfer to metallic surfaces and cause corrosion of the combustion hardware, thus decreasing the equipment lifetime. In gas turbines, ash reduces the aerodynamic path for the gas flow, and therefore the turbine performance. Values given in the literature show that a mere 0.32 cm thick deposit can cause a 10 % decrease in turbine power.

Solid particulates cause corrosion, erosion and abrasion, all of which reduce the lifetime of the hardware. Carbon particulates may also increase the radiative power of the flame, causing damage to the combustion chamber materials. In addition, there is an economic loss from losing unburned material to the atmosphere, which therefore means a decrease in fuel efficiency.

Because of the effects mentioned above optimum combustion conditions are important for the minimisation of particle and ash production. Viscous fuel oil can be atomised by preheating the fuel. Additives combine with fuel constituents and combustion products to form solid, innocuous products that pass harmlessly through the combustion equipment and may be used to support the optimum combustion conditions. In older oil-fired boilers, burners with mechanical atomisation were installed. The improved design of burners with steam atomisation gives a more efficient combustion of HFO, and results in lower particulate emissions. PM emission concentrations in the raw gas (before dedusting) of lower than 100 mg/Nm3 may be achieved, though this depends greatly on the ash content of the HFO.

Particulate emissions are normally reduced by ESPs. Particles are generally collected in an ESP in a dry form, which can then be landfilled in controlled landfills. The ash resulting from fuel oil combustion presents a high content of unburned carbon. This ash can therefore be incinerated (in industrial kilns), or can be re-injected into the combustion chamber of a boiler. Fly ash from oil firing installations is regarded as hazardous waste.

Abatement of SO_2 emissions

Sulphur is usually found in hydrocarbon fuels, normally up to a maximum of 3 % by weight, and mostly in organic form, although it also exists as inorganic compounds. Heavy fuel oils usually contain higher amounts of S than other petroleum products, as it tends to concentrate in the residue along with asphaltenes during the refining processes.

At the high temperatures and oxygen concentrations typical of combustion, sulphur combines with carbon, hydrogen and oxygen to form SO_2, SO_3, SO, CS, CH, COS, H_2S, S and S_2. Under such circumstances almost all of the sulphur is in the '+4' oxidation state, hence SO_2 is the predominant sulphur compound formed in combustion. Even with a 20 % air deficiency, 90 % of the sulphur is in the form of SO_2 and as little as 0.1 % is as SO3; with SO accounting for the remainder of the sulphur.

At lower oxygen concentration (40 % deficiency) H_2S, S_2 and HS are also present in significant proportions, while SO3 is negligible. During combustion these species are in super-equilibrium concentrations. As the gases cool, their rates of consumption decrease and equilibrium may be "frozen" before the products reach room temperature.

In oxygen-rich flames, i.e. normal operation in combustion facilities, SO and SO_3 are present, as well as H_2SO_4 as a result of the combination of SO_3 and H_2O. Sulphuric acid is responsible for corrosion in combustion equipment. This is a major reason for controlling sulphur combustion.

Switching to low-sulphur oil might be a technique which can make a significant contribution to SO_2 emissions reduction. A decrease of 0.5 % in the oil sulphur content leads to a decrease in the emission value by about 800 mg/Nm3. To reduce SO_2 emissions from liquid-fuel-fired boilers, especially those burning HFO, some plants apply wet scrubbers. The figure below shows a wet scrubber applied to an Austrian HFO fired boiler.

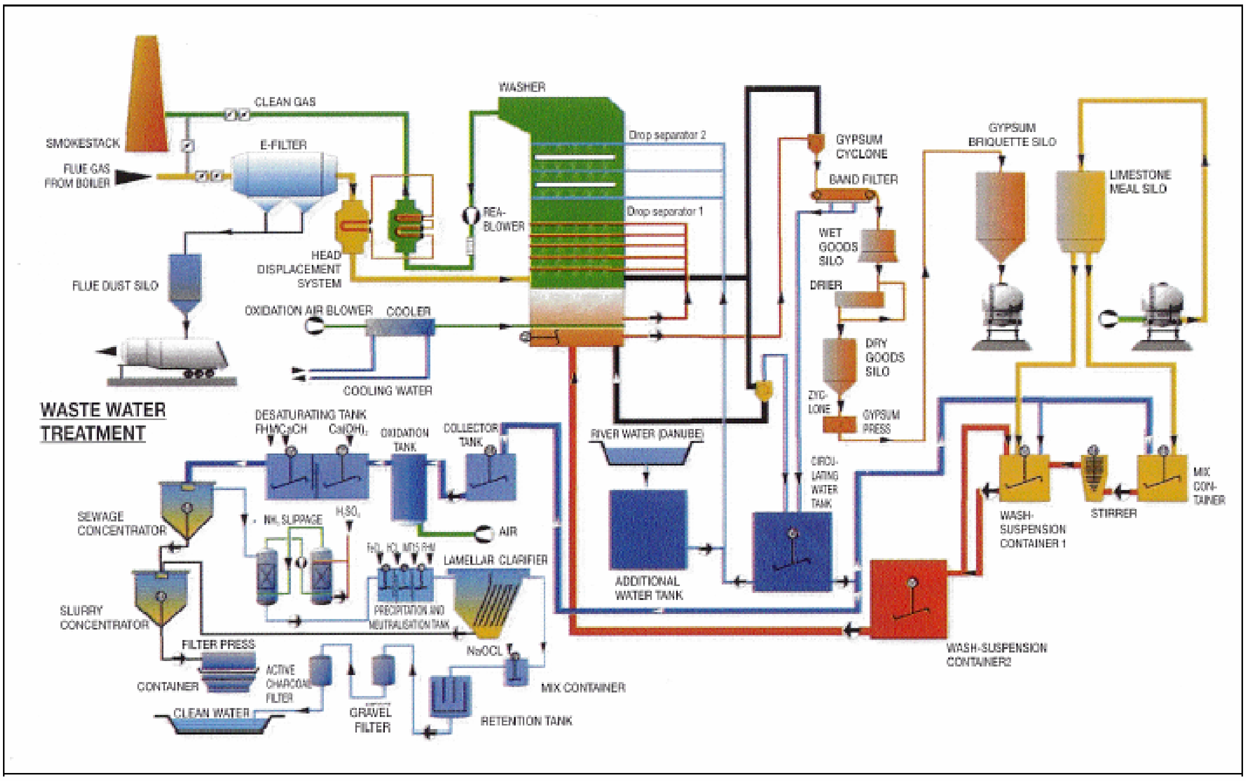


Figure: Wet FGD process applied to a HFO fired boiler

<u>Abatement of NOx emissions</u>

With conventional fuels, the NOx formation rate very much depends on the gas temperature and the amount of nitrogen in the fuel. Both characterise the most important routes for the formation of NOx. The thermal NOx can be controlled through a reduction of the flame peak temperature (e.g. limited combustion chamber load). The quantity of fuel nitrogen must also be considered and should be limited in supply contracts if necessary. The NOx concentration in the exhaust of an oil-fired boiler indicates that the NOx concentration decreases with excess air. The boiler size also plays an important role in the concentration of NOx in the flue gases. Factors such as the method of firing have little influence.

For oil-fired boilers, the usual excess air is in the range of 2 - 4 % O_2 (in flue gas). A low excess air combustion will be characterised by 1 - 2 % O_2. This technique is rarely used alone, but is very often used in combination with ‘Low-NOx burners’ or ‘Overfire Air’.

Flue gas recirculation is more often used in oil- or gas-fired boilers than in coal-fired ones. The higher combustion temperature improves the NOx reduction through the addition of cold clean flue gas. This technique is often used in combination with low-NOx burners and/or OFA, together achieving a 60 - 75 % reduction from the original NOx emission baseline level.

Amongst all the air staging techniques, the most commonly used in oil-fired boilers are ‘burners out of service’ (BOOS) and ‘Overfire Air’ (OFA). With modern OFA designs (optimised nozzle design, separated and swirled air flux), the NOx reduction can be as high as 60 % in tangential firing units.

Flue gas recirculation type burners are used in oil-fired boilers, matched with the various types of Low-NOx burners (LNB) and achieves a corresponding NOx emission reduction of 20 %. The key point in designing an efficient oil LNB is to ensure a good oil atomisation coupled with the burner aerodynamics, so as not to increase the carbon-in-ash level while decreasing NOx. Modern LNB designs with a proper oil atomisation system can reach a 50 % NOx reduction. For oil-fired plants in general, the NOx emission reduction limits with low-NOx burners are 370 - 400 mg/Nm3 (at 3 % O_2).

In oil-fired boilers, reburning can be implemented with gas or oil as the reburning fuel. Gas is more commonly used than oil. Reburning is interesting for new power plants but is less adapted to existing units. Many existing oil-fired boilers have been equipped with gas/oil reburning during recent years (e.g. Italy has units from 35 to 660 MWe). It is important to note that these units have all been equipped with at least OFA and flue gas recirculation at the same time, and some of them with low-NOx burners. The share of the reburning fuel is 10 to 15 % of the total thermal input. The corresponding NOx reduction is 55 - 80 % from the original NOx baseline level for oil reburning and 65 - 80 % for gas reburning.

Secondary measures such as SNCR and SCR systems have been applied to a number of oil-fired combustion plants. In Europe, SCR systems are applied, in particular, in Austria, France, Germany, Italy and the Netherlands, whereas outside Europe they are mostly applied in Japan. The SCR technology has proven to be successful for liquid-fuel-fired power plants.

6.2.2 Gas fired steam boilers

The large gas-fired boiler design is similar to that of the oil-fired boilers as described in the previous chapter. The heat from the combusted fuel is used for the production of superheated steam, which expands in a steam turbine that drives a generator. In order to efficiently convert the energy from the steam to electricity, modern gas fired boilers use supercritical steam parameters, which produces plant efficiencies of up to 48 % in the condensing mode and fuel utilisation figures of 93 % at combined heat and power production. The application of double reheat and increase of the supercritical steam parameters to 290 bar and 580 °C can reach these high efficiencies.

The burners of the boilers are in general arranged in several levels in the walls (front firing or opposed firing) or at several levels tangentially in the four corners of the boiler. Firing systems for gas-fired boilers are similar to coal- or oil-fired boilers.

6.3 Refurbishment of oil to gas fired gas power plants

Recently in Peru a power plant has been refurbished to replace the use of diesel and convert to natural gas. The owner of the plant is Empresa de Generación Termoeléctrica Ventanilla S. A. (ETEVENSA), Lima. The installed power of the diesel fired plant amounted to totally 340 MW with 2 units, 170 MW each. The diesel fired turbines have now been converted to gas fired and are operating with natural gas since the end of August 2004. Typically the effective capacity was reduced by the measure to now 325 MW (production: 2002: 9.52 GWh; 2003: 6.15 GWh) which is 15 MW lower than the prior nominal figures with diesel. This is due to the different heat and radiation properties of gas flames and the respective adjustments to be made in the control systems. In order to improve the efficiency and the power output again the owner is planning to install a heat recovery boiler to establish a combined-cycle system.

In Peru there are three other power plants also interested in refurbishing to use natural gas. Countries of the Southern Cone plan as well the elimination of oil fired plants by converting the plants to natural gas firing.

Activities like these are re-powering measures which supplement either an existing gas turbine plant (in line with a swap from diesel / fuel oil to natural gas) by adding heat recovery boiler(s) or an existing steam power plant by adding gas turbines and heat recovery boiler(s) in order to realise a gain in overall power output and efficiency. Principally, it consists of transforming an existing conventional power plant into a combined-cycle system, as pure combined-cycle re-powering results in the most efficient arrangement.

For re-powering a steam power plant the following 3 main technologies are available that are based on commercially proven experience:

- Heat recovery re-powering / pure combined cycle re-powering
- Condensor / feedwater heater re-powering
- Boiler windbox re-powering

6.3.1 Heat recovery re-powering

Heat recovery re-powering systems are the most common application of re-powering. These systems utilize gas turbine exhaust energy to generate steam in a heat recovery steam generator (HRSG), thus displacing the power boiler in the existing steam plant. The design can comprise a single throttle pressure non-reheat cycle in which all of the existing steam cycle feedwater heaters are utilized. Other cycles can be designed for increased efficiency using two- or three-pressure HRSG configurations with and without feedwater heaters.

The high exhaust temperature of advanced technology gas turbines makes re-powering a reheat steam turbine an economically viable option. Options using a three pressure level reheat HRSG are receiving considerable attention as utilities enhance use of existing sites.

A multi-pressure combined-cycle system can be accommodated by existing steam turbines that have multi-flow low-pressure sections since the crossover pipe from the intermediate-pressure section to the low- pressure section can be readily modified to accept the low-pressure steam admission. The intermediate-pressure steam is admitted to the cold reheat piping which is part of the re-powering system. If the economic evaluation requires a lower cost system, it can be provided by a two- or single-pressure system with higher heat rate.

Since combined cycles achieve highest efficiency with no extraction feedwater heaters and multiple low-pressure admissions, the throttle flow of the re-powered steam turbine must be reduced relative to its design to maintain the same exhaust flow and heat rejection to the condenser cooling water. Further, the pressure drop between the HRSG superheater discharge and the steam turbine nozzle should be minimized for highest combined-cycle efficiency. Therefore, the re-powered steam turbine should operate with valves open in a sliding pressure mode. Since the throttle flow is reduced about 25%-30% to maintain the design condenser flow, the steam pressure would be similarly decreased. Since the combined-cycle heat rate is relatively insensitive to steam pressure, the reduced steam pressure does not significantly increase the plant heat rate. Economics may justify steam turbine modifications to improve efficiency in some applications. The performance change is application specific and depends on the match of the new gas turbine with the existing power plant. Because heat recovery re-powering leads to the largest improvements in net plant output and heat rate, most of the industry focus today is on this re-powering approach.

6.3.2 Condensor / feedwater heater re-powering

In a fossil steam plant, approximately 20% to 30% of the throttle steam flow is typically used for feedwater heating. If the feedwater heating duty was supplied by the gas turbine exhaust energy, then additional steam would be available for passing through the entire length of the steam turbine. In practice, the amount of additional steam passing ability is limited by the exhaust loading of the steam turbine, the heat rejection duty of the condenser or cooling towers and/or the site license discharge limits. The gas turbine is used to heat feedwater in the economizer before the feedwater enters the boiler. Feedwater to the economizer can be taken from the condenser or following any combination of heaters. The greatest improvement in cycle heat rate occurs, if all existing feedwater heaters are displaced.

6.3.3 Boiler windbox re-powering

Boiler windbox re-powering systems utilize gas turbine exhaust gas as preheated combustion air in the existing boiler. In this application, the hot, oxygen-rich gas turbine exhaust gas provides the function of the forced draft fan and air heater. The heated combustion air reduces the boiler fuel requirements.

Windbox re-powering displaces the air preheater and would result in a high stack gas temperature, if no modifications of the boiler heat recovery sections were made. In most instances, additional economizer surface will be added to the boiler, transferring this duty from the steam turbine extraction cycle to the boiler, in order to arrive at a reasonable stack gas temperature for the re-powered configuration.

Additional issues in this form of re-powering include the quantity of gas turbine exhaust flow relative to boiler needs, the exhaust pressure losses imposed on the gas turbine, and possible steam system derating due to the reduced oxygen content from turbine exhaust gases relative to ambient air.

6.3.4 System selection factors

The selection of the most economic re-powered configuration for a specific application is dependent upon many factors. These include:

Fuel	Natural Gas Light Distillate Oil Coal
Duty Cycle	Base Load Mid-Range Daily Start-Stop
Steam Plant	Non-reheat Reheat Turbine Size Type of Cooling Cooling Water Temperature
Environmental Requirements	Emissions Thermal Discharge
Economic Factors	Fuel Cost Interest Rate Fixed Charge Rate Life of Plant

The most appropriate configuration has to be decided individually for each project.

6.4 Coal fired power plants

6.4.1 Pulverised fuel combustion

Since its introduction in the 1920s, pulverised fuel (PF) combustion has been the mainstay of coal-based power generation and is likely to dominate the market well into the future. Over the years, PF technology has been the subject of continuing development effort, but perhaps the most significant recent development has been the introduction of advanced boilers capable of operating under supercritical steam conditions.

In PF combustion fuel is blown with air into a boiler furnace. There are "sub-critical" and "supercritical" boilers. PF boilers are termed "sub-critical" if the steam generated is below the critical pressure of 221.2 bar. Above this pressure, there is no distinct water/steam phase transition, and the boiler is named "supercritical". Compared with sub-critical power generation, the increased thermal efficiency of supercritical boiler technology has brought benefits of reduced fuel consumption and reduced emissions of harmful pollutants. As a result, supercritical steam cycles have gained rapid acceptance in OECD countries, with some 19.4 GWe of supercritical plant commissioned between 1995 and 1999 compared to just 3.0 GWe of sub-critical capacity.

In PF combustion, coal is finely ground and then blown with air through a number of burners into a boiler furnace. The coal burns and the heat released is used to produce high-pressure superheated steam. This is then charged to a steam turbine/alternator set to produce electricity. Boiler units are typically large (300-1000 MWe) and matched with a single dedicated turbine/alternator set.

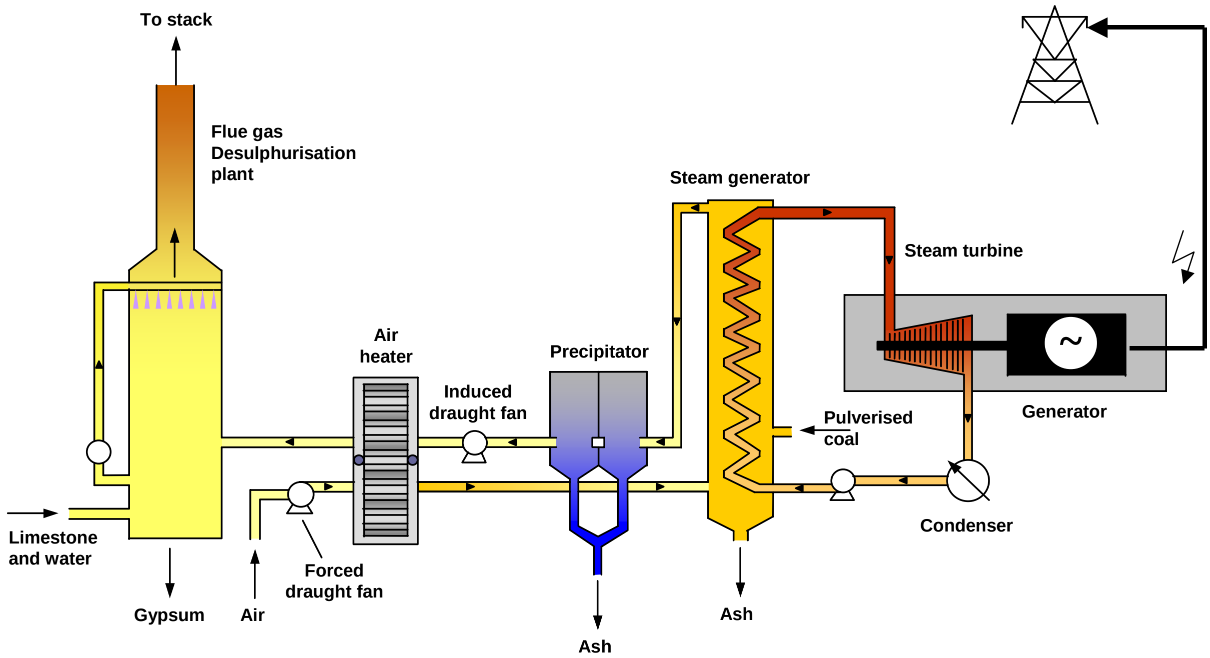


Figure: Schematic diagram of a typical PF power plant

Currently, the state-of-the-art supercritical pf plants currently operate at up to 300 bar and 600ºC, with net efficiencies ~45%, depending on coal type and plant location. Ålborg Power Station Unit 3 at Vendsysselværket, Denmark - a double-reheat supercritical 285 bar/580ºC, 412 MWe coal-fired plant - currently achieves 45.1% efficiency.

Steam conditions and cycle efficiencies continue to improve steadily. By 2020 650-700ºC is expected to be commercially available, with cycle efficiencies in the range 50-55%. About half this efficiency gain is expected to come from enhanced steam conditions and the rest from reduced plant losses (e.g. lower flue gas exit temperatures, higher feed water temperatures, lower pressure drops, better combustion, more efficient auxiliaries) and improved operating methods.

Enhanced steam conditions put considerable demands on boiler and steam turbine materials. Work is under way to develop materials with the required strength and ductility that can withstand the highly corrosive and erosive environment pertaining to advanced steam conditions, without it advances will be forfeited. Currently, a number of new ferritic and austenitic steels are being investigated for applications up to 650ºC, whilst nickel (Ni)-based alloys are under consideration for 700ºC and above. There are now approx. 100 supercritical pf plants around the world. Besides material developments, the most significant recent advances include double reheating, reduced condenser pressure and improved turbine designs. The replacement of spiral-wound furnace tubing with vertical furnace-wall tubing represents a further imminent advance; this would be both cheaper and easier to install and maintain, and would add to the boiler efficiency through presenting a lower pressure drop.

The table below shows the most advanced PF installations in Europe, together with data on the boiler.

Power Station	Fuel	Output net [MWe}	Steam pressure [bar}	Main steam temp. [°]	Reheat steam temp. [°]	Net efficiency LHV [%]	Year of Commis-sioning
Niederaussem (D)	lignite	965	275	580	600	45.2	2002
Avedore (DK)	coal	390	290	580	600	48.3	2001
Boxberg (D)	lignite	907	266	545	581	41.8	2001
Lippendorf (D)	lignite	930	267	554	583	42.3	2000
Nordjyllands (DK)	coal	411	290	582	580	47	1998
Schwarze Pumpe (D)	lignite	1600	267	547	560	41	1998
Skaerbaek (DK)	nat. gas	411	290	582	580	49	1997
Schkopau (D)	lignite	950	285	545	560	40	1995
Hemweg 8 (NL)	coal	630	260	540	568	42	1994
Esbjerg (DK)	coal	411	250	560	560	45	1992
Staudinger (D)	coal	509	262	545	562	43	1992

Table: Selected state-of-the-art supercritical steam power plants in Europe

One of the world's largest and most environmentally friendly lignite-fired power plants "Schwarze Pumpe" is situated in the state of Brandenburg, some 60 km northeast of Dresden in Germany. The plant has two 800 MWe units and was built as the first of a series of three plant of this type. The units entered commercial operation between November 1997 and May 1998. The power plant's most important task is to generate base-load power for the public power grid. Designed with extraction condensing turbines, this power plant also supplies district heat to surrounding towns and villages and process steam to the neighbouring briquette factory. The power plant can also provide an immediate reserve of 5% of rated capacity in 30 seconds for grid frequency regulation.

The units in the tale are characterised by supercritical steam conditions, as well as single reheat and variable-pressure operation. They achieve a net electrical efficiency of more than 41% and a fuel utilisation factor of up to 55%. With advanced combustion processes and efficient flue-gas scrubbing systems, plant emissions remain safely within strict statutory limits, and in most cases by a significant margin below it.

6.4.2 An option for the future - Integrated Gasification Combined Cycle (IGCC)

An alternative to coal combustion is coal gasification. When coal is brought into contact with steam and oxygen, thermo-chemical reactions produce a fuel gas, largely carbon monoxide and hydrogen, which when combusted can be used to power gas turbines. Integrated Coal Gasification Combined Cycle (IGCC) power generating systems are presently being developed and operated in Europe and the USA. These systems give increased efficiencies by using waste heat from the product gas to produce steam to drive a steam turbine, in addition to a gas turbine. Existing commercial systems achieve efficiencies close to 45%. With recent advances in gas turbine technologies these systems are capable of reaching above 50%. IGCC systems additionally produce less solid waste and lower emissions of SO_X, NO_X and CO_2. Over 99% of the sulphur present in the coal can be recovered for sale as chemically pure sulphur.

In a typical integrated gasification combined cycle (IGCC) power-generating plant, pulverised coal is fed into a gasifier at about 30 bar pressure, together with O_2 from an air separation unit (ASU). The raw fuel-gas is produced in the gasifier at about 1300ºC and is cooled to about 200ºC before being scrubbed with water to remove compounds such as NH_3 and hydrogen chloride (HCl). It is then further cooled and scrubbed with a solvent to remove sulphur compounds such as hydrogen sulphide (H_2S). The cleaned gas is then fired in a gas turbine. Ash in the coal is recovered as a mineral slag from the gasifier and the sulphur compounds removed from the gas are recovered as sulphur. N_2 from the ASU is typically added to the fuel-gas in the gas turbine to control NOx emissions.

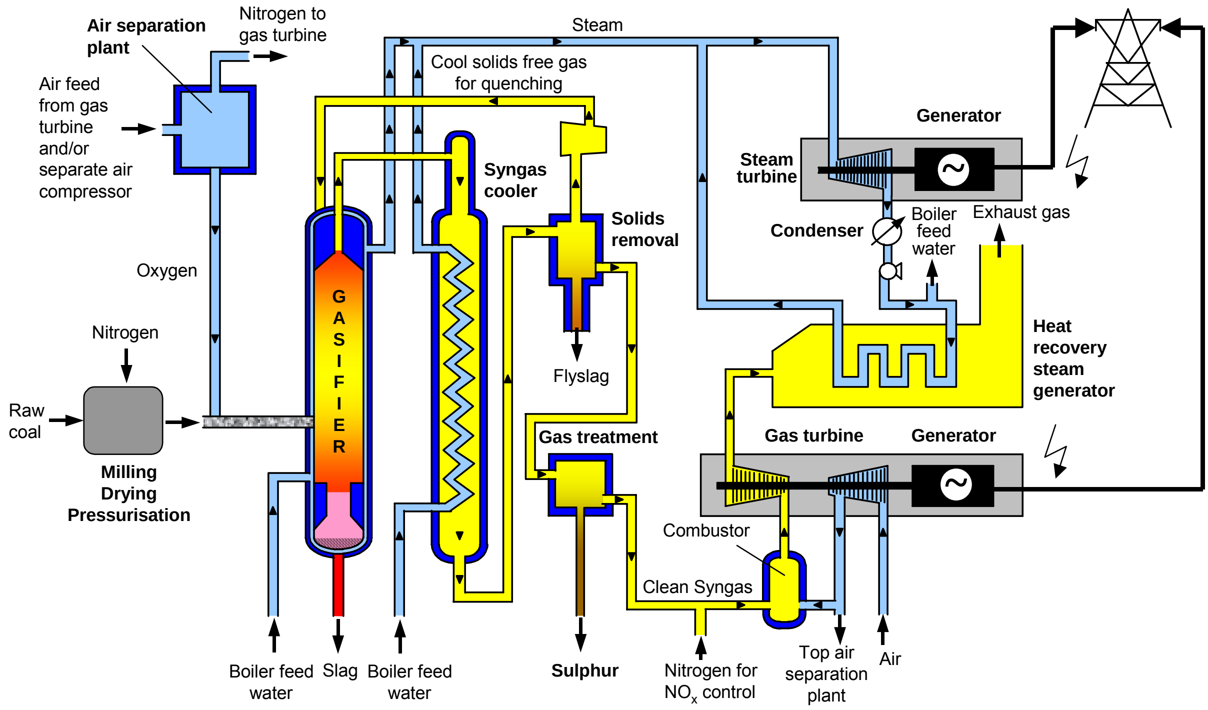


Figure 1: Schematic representation of an IGCC power plant

Further development work is required to overcome reliability and operational flexibility problems, and to reduce the cost. However, these obstacles to adoption are gradually being eroded. In the short-to-medium term, R&D effort is focusing on three major areas shown hereinafter:

- Enhanced understanding of gasification (to establish the fuel flexibility of IGCC technologies - directed at understanding gasification reaction rates and carbon conversion and predicting the gasifiability of individual coals and other fuels, ash/slag behaviour, and the potential for sulphur capture in fluidised bed gasifiers)

- Improved individual plant components (more reliable and/or cheaper gasifiers/syngas coolers, pressurised coal feeding systems, gas clean-up, gas turbines and ASUs)
- Improved overall process layout and design (specifically dynamic simulation, start-up and shut-down strategies, operability, simplified designs that reduce cost, and optimum integration strategies).

IGCC technology is based on a partial oxidation of coal aimed at producing a synthesis gas essentially made of hydrogen and carbon monoxide. This syngas is afterwards dedusted and desulphurised prior to be used to fuel a combined cycle.

The main advantages of IGCC are:

- an extensive desulphurisation through the use of efficient petrochemical processes,
- a high efficiency already reaching 45% and potentially above 50% in the future, due to the use of a combined cycle scheme, which helps reducing the greenhouse effect,
- low NOx emissions through NOx reduction systems equipping the gas turbine combustion chambers,
- vitrified ashes which are inert and thus preclude soil contamination,
- the capability to use high sulphur bearing fuels as well as industrial wastes and residues.

Disadvantages of IGCC are:

- High capital costs
- Complexity of installation

The Puertollano project involved the development of the world’s largest Integrated Gasification Combined Cycle (IGCC), 330 MWe, power plant. In 1992, the environmental advantages of this coal gasification technology gained the support of the European Commission under the THERMIE Programme, as a targeted project. In addition, 8 major European utilities and 3 technology suppliers formed a consortium named ELCOGAS to manage the project.

The plant was originally designed to run essentially on gas. However, following agreements reached with the Spanish Ministry of Industry and Energy, incentives were awarded to allow extensive modifications to be undertaken enabling low quality coal and coke to be used. The plant design ensured that its features were focused on two main targets: improved efficiency of 45% net and reduced emissions. Emission data for the year 2000 showed the plant’s emission levels were well below the regulatory limits specified when gas was being used.

Power Station	Fuel	Output net	Gas turbine	Steam turbine	Net efficiency LHV	Year
		[MWe}	[MW]	[MW]	[%]	
Puertollano (E)	coal	330	182.3	135.4	42.2	1997

Table: IGCC power plant at Puertollano, Spain

Figure: 330 MWe Puertollano IGCC power plant (courtesy of ELCOGAS)

The Gasification Unit is based on the PRENFLO system, an entrained-flow system with dry feeding. The syngas is produced by reaction of coal with oxygen at high temperatures up to 1600ºC. The PRENFLO process is capable of gasifying a wide variety of fuel types, and qualities of coal, for the production of synthetic gas. The “design” fuel of Puertollano power plant is a 50% mixture, by weight, of local high ash coal and high sulphur petroleum coke. The gasification process takes place in a cooled gasifier vessel, the internal surface of the wall being lined with refractory to protect the metal vessel from the hot coal gas. The slag produced during gasification provides a critical protective layer, which prevents diffusion of the gas through the refractory coating. The slag flows down the gasifier walls to be quenched and granulated before removal. The hot coal gas exits the top of the gasifier, where it is quenched to ~800°C with cooled recirculated gas. The quenched gas then enters the high-pressure steam heat exchanger, located in the same pressure vessel as the gasifier and the quenching zone, and then to an intermediate pressure exchanger located in a separate vessel.

The Gas Cleaning Unit treats the gas at the outlet of the intermediate pressure boiler removing the solid particles (using candle filters), and incorporates a water wash step (Venturi scrubber) for ammonia, HCl, HCN and trace component removal. The sulphur removal unit consists of a fixed bed catalyst (99.9% efficiency). The cleaned gas is then passed through a conditioning phase (saturation with water), before delivery to the gas turbine.

The Air Separation Unit, supplied by Air Liquide, uses air extracted as a bleed from the gas turbine air compressor, to generate oxygen with high purity (85%) for feeding to the gasifier and nitrogen for pneumatic transportation of the fuel. Nitrogen is also used as a safety purge system.

The Combined Cycle Plant is designed around a Siemens V94.3 gas turbine, a triple pressure heat recovery boiler supplied by Babcock Wilcox Espanola and a Siemens reheat generator. This equipment produces steam that is used to produce additional electric power in a conventional steam turbine with condensation cycle. The gas turbine is able to operate with both syngas and natural gas allowing greater plant flexibility.

6.4.2.1 Options for future coal based power generation technologies

There are principally two technology options considered for the next twenty years:

- Supercritical pulverised coal leading to ultra-supercritcal steam conditions (>650°C and >30 MPa), offering net efficiencies of 50% and above on an LHV basis.
- In the longer term, IGCC could become the leading technology based on present knowledge as CO_2 capture and storage becomes the norm.

Efficiency of PF has been increasing steadily from around 37% in the 1970s to around 47% today based on north European locations using seawater cooling. Early IGCC plants (Cool Water) were around 33% initially rising to around 45% today.

However, with the incorporation of CO_2 capture, efficiencies of both systems will initially be reduced substantially, by around 10-12 percentage points for PF, less for IGCC, at around 6-8 percentage points (see figure below). Both of these penalties will decrease as technology advances are made and the trends shown for the future are uncertain.

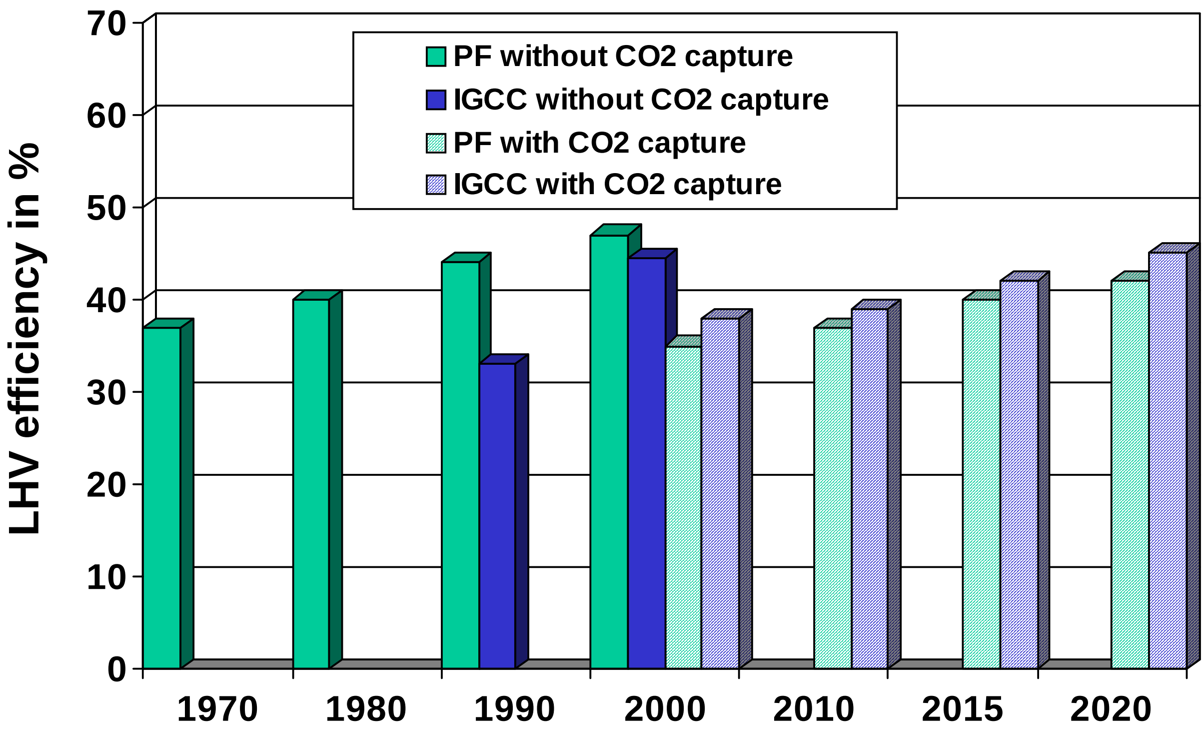


Figure: Graph of efficiencies over time for PF and IGCC with CO_2 capture penalty in years ahead.
(source: John Topper: *Clean Coal Technology and CO_2 Mitigation)*

6.4.3 Refurbishment and upgrading of existing power plants

Construction of power plants was at its highest in the years between 1960 and 1990. In the last decade, coal-fired power plant construction has declined while more natural gas combined cycle plants are being built. This trend is expected to continue especially with deregulation. As plants age they tend to become less reliable. Their performance and efficiency decline, and operating and maintenance costs increase. Derating of the plant due to equipment ageing and changes in operating regimes may also have occurred.

There are generally two methods of power plants modernisation:

- refurbishment and
- upgrading.

The cost-effectiveness of refurbishment was a subject of many studies. The review of those can be concluded as follows;

- Economic modelling of the refurbishment project compared with the construction of a new fossil plant shows a wide range of outcomes depending on the assumptions.
- Refurbishment has no clear economic advantage over the construction of a new fossil plant of equivalent capacity.

IEA has carried out a study with power plant refurbishment of existing plants that is based on the assumption that major refurbishment will take place once during the lifetime of a plant during the next thirty years. Only plants that will not be retired during this period are considered. The cost assumptions used in these calculations in case of developed countries amount to 200-300 $/kW for boilers and 100 $/kW for turbines and in case of economies in transition amount to 150-300 $/kW for boilers and 50-100$/kW for turbines.

The power plants may be burning coals for which they were not originally designed, further affecting their performance. Current environmental legislation is usually stricter than in the past; consequently older power plants may not meet the new environmental requirements.

Upgrading of existing power plants may comprise:

- retrofit of pollution abatement and control technologies using electrostatic precipitators or flue gas desulphurisation and process optimisation by installing modern instrumentation and control systems to improve plant performance and reduce operating and maintenance costs
- repowering of existing power plants with circulating fluidised bed (CFB) boilers or by integrating a gas turbine to form a combined cycle
- rehabilitation/reconstruction of entire units, of mills and pulverisers and the transport of the pulverised coal to the burners

Retrofitting is the primary concept in any modernisation scenario. Retrofitting ageing power plants with pollution control equipment or repowering with fluidised bed boilers or gas turbines can be, in contrast to refurbishment, more cost-effective than building new power plants. The evaluation of any plant for upgrading/retrofitting/repowering includes a wide range of business aspects such as load growth forecasts, financial parameters, environmental regulations and other legal requirements. For example, two reasons for upgrading older plants are to replace lost capacity and to help meet future changes in power demand. Many of these older plants were built on the assumption that they would be used at a constant high loading (base-loaded). However, the upgraded plant may be obliged to vary output to match demand (load following). Fuel represents about 60-80% of a power plant's operating costs; consequently significant savings can be made by firing cheaper fuels. The requirements and technical condition of each power plant are found to be different. Thus the suitability of a power plant for rehabilitation/retrofitting/repowering has to be determined separately for each plant. Continuous monitoring is required following the upgrade to confirm that the anticipated improvements have been achieved. Some factors need to be considered when evaluating a refurbishment project.

The most important retrofitting activities are:

- Improvement of the fuel preparation and firing system towards the increase of the burnout, the uniformity of the flue gas temperature distribution and the abatement of the air pollutants
- Implementation of techniques for further reduction of the NOx emissions and for the flue gas desulphurisation
- Improvement of particles precipitation systems
- Optimisation of the existing fuel drying system or implementation of new effective drying techniques
- Replacement, rearrangement or size change of heat exchange surfaces
- Optimisation of the heat exchanger maintenance and the soot blowers operation
- Supplementary heat exchange surfaces for further exploitation of the flue gas thermal energy
- Reduction of the boiler infiltrate air by improving the boiler sealing
- Improvement of the air preheating system
- Reduction of the ID and FD fan losses
- Improvement of the cooling tower performance
- Cold end optimisation (condenser and low pressure section of steam turbine)
- Steam turbine retrofitting (blades replacement and improvement of the labyrinths' operation and turbine control system, etc)

The effect of deregulation/liberalisation on the retrofit and/or rehabilitation of coal-fired power plants will be an increase in competition emphasising the role of the most cost-effective generation methods and locations. However, investment in retrofit or rehabilitation will be deferred until the complete development of this deregulated market. Competition and financial issues may have the initial effect of a drive to generate power at minimum cost. Upgrading or repowering may have to wait until costs are reduced even further or environmentally driven licence fees are used. Once a market is deregulated, greater demand for retrofit or rehabilitation is expected to materialise in the short-to-medium term depending on the potential and the prospects of a plant to produce power cost-effective. Deregulation can provide an economic environment which may stimulate market-driven retrofit and rehabilitation projects in the long term.

Further developments in improving thermal efficiencies, minimising environmental impact while enhancing fuel flexibility and reducing capital and operating costs, may open up more opportunities for repowering with CFB boilers. Opportunities may be further enhanced by the development of new markets for the use of CFBC residues. New designs, especially more compact boilers, may facilitate the repowering of ageing boilers. The survey results demonstrate that compliance with environmental regulation is the driving force for retrofit of air pollution abatement and control systems, and market competition is the main driving force for repowering. The most important factor is the competitive lifetime of the modified plant. The likely competitive period income needs to be significantly greater than the project costs. Legislation on reducing greenhouse gases would increase the potential for repowering with gas turbines.

Another important upgrading factor is renovating equipment to increase fuel flexibility which allows the operator to take advantage of cheaper coals on the spot market. Coal blending is receiving increasing attention from power generation companies worldwide. It is used to produce coal of the correct quality for the intended use at the lowest price. Cheap coals can be blended with low-sulphur coals, for example, to produce a mix that meets the relevant legislation at the lowest price. Coal blending is used routinely in countries depending heavily on imported coal such as Japan, Denmark and the Netherlands. Improved performance is being gained from more appropriate coal selection/blending, handling and grinding, improved pf flow distribution and metering, and accurate monitoring and 'intelligent' control of other plant parameters. Improved instrumentation and data analysis/interpretation is also enabling operating costs to be lowered by more effective and timely maintenance that improves plant reliability and availability, reduces overall maintenance costs and extends plant life.

Instrumentation has been developed and is now being applied to monitor on-line parameters such as coal handleability, bunker flows, milling performance, distribution of pf to burners and unburnt carbon in ash. Data generated in this way are being analysed and interpreted by 'expert' systems, and used for control purposes allowing a NOx emissions reduction by up to 25%.

A significant reduction of NOx generated by the combustion process can be achieved through modifications either to the burner or to the furnace. During coal combustion, NOx can be formed either from nitrogen in the combustion air or from the coal itself; how much depends on the availability of O_2, the air temperature, the temperature-time history experienced by coal particles, and coal properties such as volatile matter content and reactivity. Combustion modifications hence aim to reduce both the supply of O_2 and the local temperatures in the furnace. Some relevant parameters (e.g. furnace volume) are difficult to change; however, significant NOx reduction can be achieved by fine tuning, improved control systems and balancing fuel/air ratios. Low-NOx burners are designed to control the initial mixing of air and fuel, to maintain the temperature and O_2 levels in critical parts of the flame at the minima necessary for effective combustion. They are now widely installed and can reduce NO emissions by 50-70%. Air staging aims to reduce the level of O_2 in zones where it is critical for NOx formation. It can be applied in the furnace or in the burner and 20-40% NOx reduction has been achieved on full-scale plant. Through the combination of Low-NOx burners with furnace air-staging 50-80% NOx reduction can be achieved. Fuel staging i.e. reburning aims to reduce the NOx already formed. The technique involves injecting fuel into a second combustion zone generally above the main combustion zone. The reburning allows a NOx emissions reduction by 50-60%.

6.4.4 Flue gas cleaning

Flue gas treatment can achieve virtually any level of emissions clean up. However, retrofitting these technologies often has considerable practical and economic implications. Installing FGD and NOx control will typically add 25% to the cost of new PF plants and can represent about 30% of plant capital costs when retrofitted to existing plants. It also increases annual operating costs by 5-10% and reduces plant efficiency by around 2%.

<u>NOx</u>

A number of processes have been developed for removing NOx from flue gases. These processes fall into one of three categories:

- selective catalytic reduction (SCR)
- selective non-catalytic reduction (SNCR)

- combined processes for SO_2 and NOx (SNOx) removal.

SCR methods, which involve the injection of NH_3 in the presence of a catalyst, can reduce 80-90% of NOx to molecular nitrogen (N_2) and water vapour. SCR is selective in that it does not oxidise NH_3 or SO_2. It is expensive to install and operate as catalysts have limited lifetimes. Non-catalytic methods, which involve the injection of urea or NH_3 directly into the furnace, are also available. The NOx –reduction rates are somewhat lower, typically 40-50%.

<u>SO_2</u>

SO_2 is emitted from coal combustion through oxidation of the sulphur in the coal. The coal itself can be treated before combustion (i.e. via coal preparation) to reduce its sulphur content, but FGD is mainly used to remove SO_2 after combustion. Two main FGD options are available, each capable of removing >95% of SO_2:

- regenerable (eg the Wellman-Lord process)
- non-regenerable (wet scrubbing and sorbent injection).

Although both use a sorbent, eg lime or limestone, regenerable processes use the sorbent as a carrier for the SO_2 and can be regenerated for further use; by-products are elemental sulphur or a concentrated SO_2 stream useful for sulphuric acid manufacture. Few commercial plants are available because they are more complex and costly to install. In non-regenerable systems, the SO_2 combines permanently with the sorbent to form a new compound. The majority of FGD facilities installed on coal-fired plant are of this type, of which wet scrubbing is the most common. The sorbent is usually mixed with water before being brought into contact with the flue gas. The residue, a wet mixture of calcium sulphite and calcium sulphate, is dried and completely oxidised to form gypsum that is used extensively in the building industry.

Spray-dry systems have been developed as an alternative to wet FGD. Sorbent is injected directly into the flue gas (alone or in combination with in-furnace desulphurisation). These are less costly to install but have higher operating costs and are, therefore, better suited to smaller plant or plant with lower load factors. Like wet scrubbers, the waste product (sodium or calcium sulphate) is mixed with the fly ash.

<u>SNOx</u>

Combined processes for removing NOx and SO_2 from flue gases are just now achieving commercialisation. Processes capable of removing both gases include the use of activated carbon reactor beds, microbial removal and electron beam irradiation. All these systems tend to be complex and are currently expensive. A 300 MW full-scale SNOx plant began operation in Denmark (Ålborg Power Station) in 1991. A 5 MW pilot plant also exists for a combined particulate, SO_2 and NOx removal system. Development of these systems may be encouraged by their potential for producing refinery products like sulphur or sulphuric acid.

<u>Particulates</u>

The two main technologies used to control particulate emissions from large-scale coal-burning plant are electrostatic precipitators (ESPs) and fabric filters or “baghouses”.

ESPs are most commonly chosen for large boilers. In these, the dust-laden flue gases are passed horizontally between collecting plates, where an electrical field creates a charge on the dust particles. The particles are drawn towards the collecting plates, where they accumulate. They are dislodged periodically by vibrating the plates and fall into a hopper for removal. ESPs are capable of removing >99.5% of particulates and meeting all current emission standards for particulates. ESPs are generally not effective with coals containing <1% sulphur. However, there are a number of technologies available that can improve their efficiency. Sulphur trioxide (SO_3) injection can be used to condition the fly ash particulates to improve their resistivity; precharging can be used to improve removal; and ESP controllers can be upgraded to digital processes that employ pulse energisation.

Fabric filters can remove up to 99.9% of particulates and are the main alternative to ESPs. They are less sensitive to dust loading or ash characteristics than ESPs and are, therefore, more flexible. However, they are also more expensive to construct and operate. A baghouse consists of a large surface area of porous fabric that filters out particulates. Dust builds up on the surface of the fabric and this in turn assists the collection process. The bag is cleaned intermittently by reverse-pulsing air through the filter. This dislodges the dust and allows it to fall into a hopper. Much research has been conducted into fibre materials used to make the bags, and organic coatings to improve temperature stability and resistance to chemical and mechanical attack. Modern materials also allow for the development of more robust ceramic fabric filters, metallic fabrics and rigid filters that can be used in higher-temperature flue gases.

Power Station	Fuel	Output [MWe]	NOx [mg/Nm³]	SO_2 [mg/Nm³]	Particulates [mg/Nm³]	Year
Boxberg (D)	Lignite	907	150	350	10	2002
Tachibana-Wan (J)	Coal (< 1% S)	2x1050	90	143	10	2002
Hawthorne (USA)	Coal (< 1% S)	550	65	150	22	2001
Hekinan (J)	Coal (< 1% S)	2x1000	30	75	5	2001
Tomatoh-Atsuma (J)	Coal (< 1% S)	2x700	100	143	10	2000
Haramachi (J)	Coal (< 1% S)	2x1000	120	200	25	1997
Mellach (A)	Coal (< 1% S)	250 + heat	180	110	10	1986
New Units (Japan)	Coal (< 1% S)	700÷1000	50	75	5	

Table: Best effective emission values for the main pollutants in coal fired power stations world-wide at 6% $O_{2,}$ dry volume basis.

6.5 Costs of electricity generation

6.5.1 Cost of electricity

The cost of electricity is a specific term related to MWh of electricity produced. It consists mainly of capital cost, fuel cost, and operation and maintenance costs. In the current trend towards deregulation of the power generation industry the cost of the generated electricity is a key element when selecting the type of power plant for a given application. Other factors that are evaluated include:

- permitting procedure
- financiability, loan structures
- environmental concerns (nuclear waste, air emissions, water consumption, heat rejection, noise)
- construction time, depreciation period of the project, etc

Every power plant is designed to keep the production cost as low as possible. Legislation and environmental protection give boundary conditions to this goal.

It should be noted that the presented information can vary depending on local and regional conditions, and therefore represents general trends (e.g. fuel gas prices can be regionally below half of world market prices making plants using fuel gas even more competitive).

Capital costs per unit of electricity for a given power plant depend on the price and the amortization rate for that plant, on interest or on the desired yield on capital investments (annuity factor), and on the load factor of the plant. Capital costs are also influenced by the interest during construction.

Fuel costs per unit of electricity are proportional to the specific price of the fuel and inversely proportional to the average electrical efficiency of the installation (this average electrical efficiency must not be mixed up with electrical efficiency at rated load).

Operation and maintenance costs consist of fixed costs of operation, maintenance and administration (staff, insurance, etc.) and the variable costs of operation and maintenance, and repair (consumables, spare parts, etc.).

By adding the capital cost, fuel cost and operation and maintenance cost the cost of electricity is calculated. Present value is generally the basis used for economic comparisons. The various costs for a power station are incurred at different times but for financial calculations are corrected to a single reference time, which is generally the date on which commercial operation starts. These converted amounts are referred to as present value.

The equivalent utilization time at rated output is the electrical energy generated by a plant in a period of time divided by the rated output. This definition enables corrections to be made for the effects of different operating modes (e.g. part-load operation) for the power plants under consideration in an electrical grid, so that they can be analyzed on a comparable basis.

It is important to understand that the cost of electricity is made up of fixed and variable costs.

Fixed costs are:

- interest and depreciation on capital
- the fixed costs of operation, maintenance and administration (e.g. staff)

Variable costs are:

- the fuel used
- the variable costs of operation, maintenance and repair (e.g. spare parts)

For a time of low demand and high supply (e.g. night hours), power stations can quote a price as low as the variable costs and, for short periods of time, an even lower figure, since stopping a station also incurs costs. During times of high demand (e.g. noon peak) they can quote at a level which will recuperate additional fixed costs. For reasons of simplicity, the average cost of electricity will be used for the following comparisons.

6.5.2 Competitive standing of combined-cycle power plants

On the following sections, the combined-cycle power plant is compared with other thermal plants.

The main range of ratings under consideration is between 30 and 1000 MW. Combined-cycles with a smaller output can, of course, be built but they are less interesting for pure power generation, because the relative cost increases as the power rating decreases. These are optimally used for heat and power production (e.g. district heating or process-steam delivery at the same time as power generation).

6.5.2.1 Comparison of turnkey prices

The figure below shows how specific investment costs for the various types of power plants depend on the power output. These costs are valid for turnkey installations. They are based on 1998 price levels and progress payments and do not include interest during construction. The data shown indicates trends, so appropriate caution must be taken in applying them, since many factors affect the price of a power plant-site-related factors such as soil conditions; earthquake factors; noise limits; types of cooling and corresponding structures; emission limits; labour rates; commercial risks; legal regulations, and so forth. The figure also shows the low investment costs required for the gas turbine, which have contributed significantly to its wide spread acceptance.

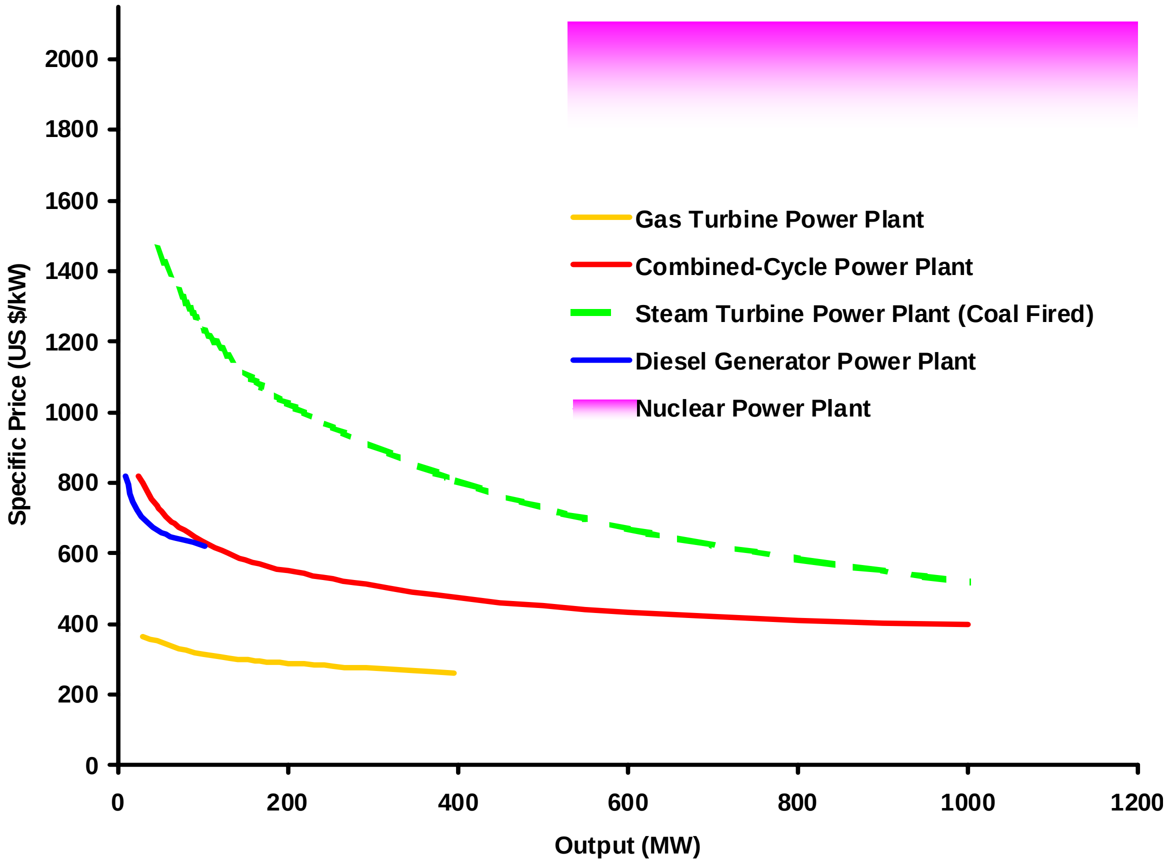


Figure: Comparison of different turnkey power plants in terms of specific price and output

Taken together with its simplicity and short start-up time to full load, the gas turbine is an attractive peak-load machine. Steam power plants are more expensive than combined-cycle power plants. Combined-cycle plants are quite inexpensive and therefore easier to finance compared to conventional power stations.

The following figure shows the breakdown of the total cost in a combined-cycle plant between the main equipment.

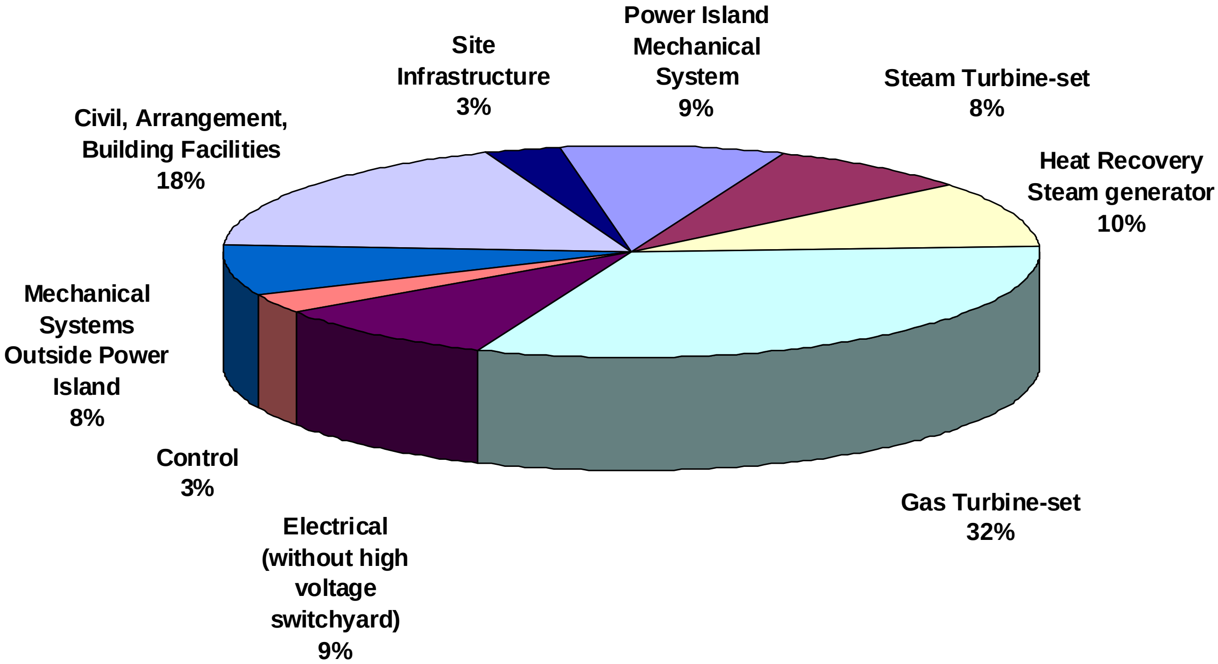


Figure: The cost percentage of the different plant areas for a typical 400 MW turnkey combined cycle plant

6.5.2.2 Comparison of efficiency and fuel costs

At today's fuel prices, efficiency is an important factor for installations operated at intermediate or base load. If an expensive fuel like liquefied natural gas (LNG) is used, the efficiency is crucial. For that reason high efficiency is a prerequisite for having an economical plant.

The figure below indicates how electrical efficiency at rated load for the different types of power plant relates to the power output. Steam turbine power plants have been segregated into coal fired and nuclear plants. The combined-cycle plants are without supplementary firing. The chart points out the thermodynamic superiority of the combined-cycle plant. This was made possible, to a large extent, by gas turbine technology which already achieves an efficiency of 38% to 40% with a turbine inlet temperature of 1300°C. Only a few years ago, the efficiency of a newly installed coal-fired steam power plant was at these levels-but with much a higher investment cost and complexity.

Some gas turbines can burn heavy oil or crude oil. Gas turbines with large combustion chambers and single burners are better capable of burning heavy fuels than those with several burners/combustion chambers since the latter are more sensitive to changes in flame length, radiation, etc. Modern gas turbines with high firing temperatures are, in general, not designed for heavy fuel operation, but mainly for natural gas and distillate oil.

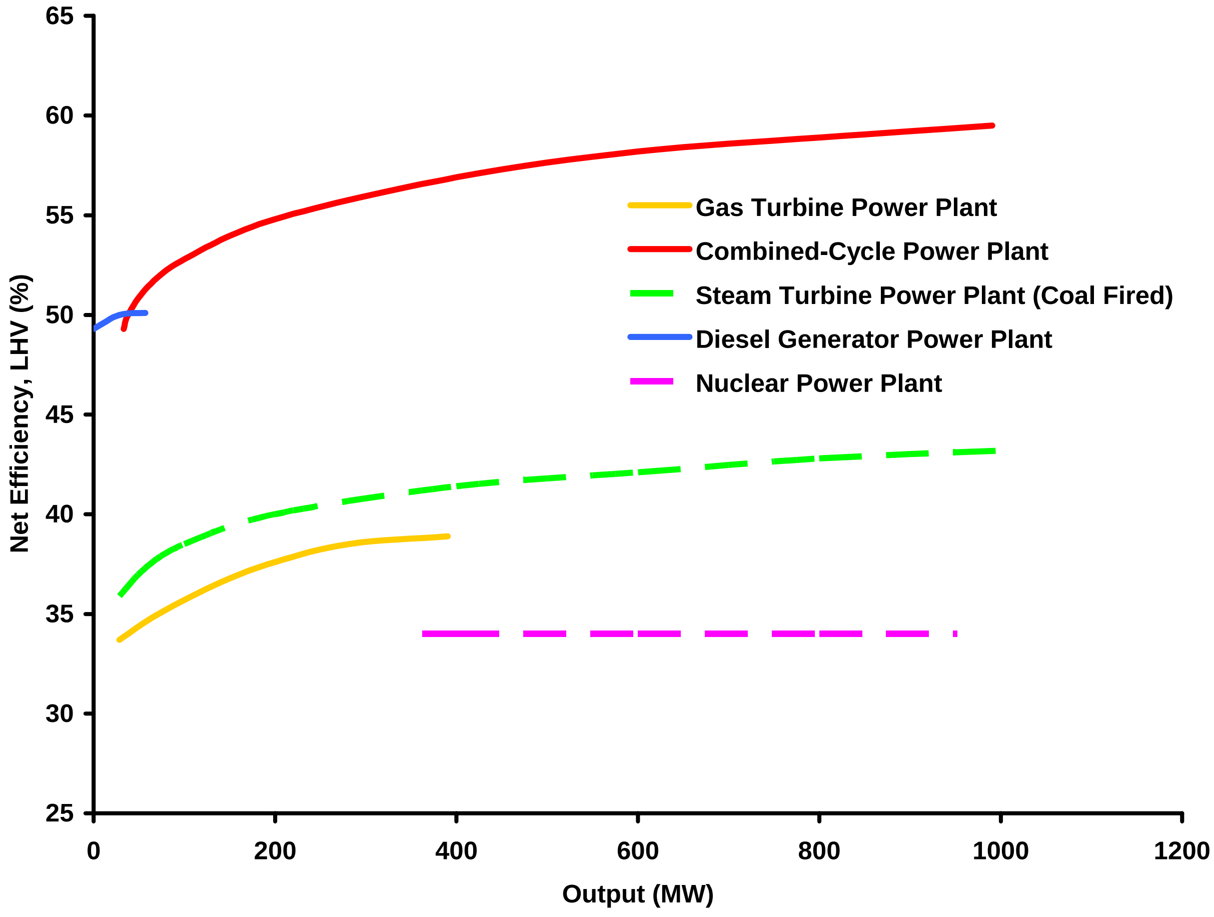


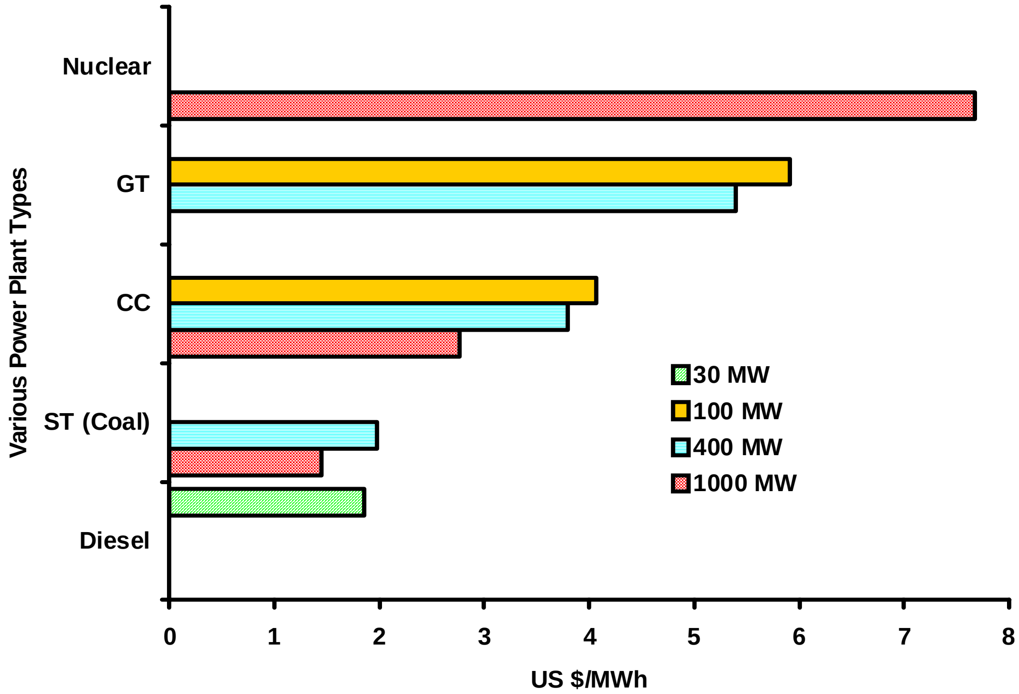
Figure: Net efficiencies for Gas Turbines, Combined Cycle, Steam Turbine (Coal Fired), Nuclear and Diesel Power Plants

When determining the specific fuel costs of power generation, efficiency is one factor. The other is the price of fuel - specifically, the fuel cost portion in the cost of electricity is the ratio of fuel price and efficiency. A power plant can remain competitive despite a low efficiency, when the fuel used is cheap.

Fuel selection and the corresponding type of power plant is determined not only by short-term economic considerations, but also in accordance with political criteria and assumptions about long-term developments in the prices of the various fuels available.

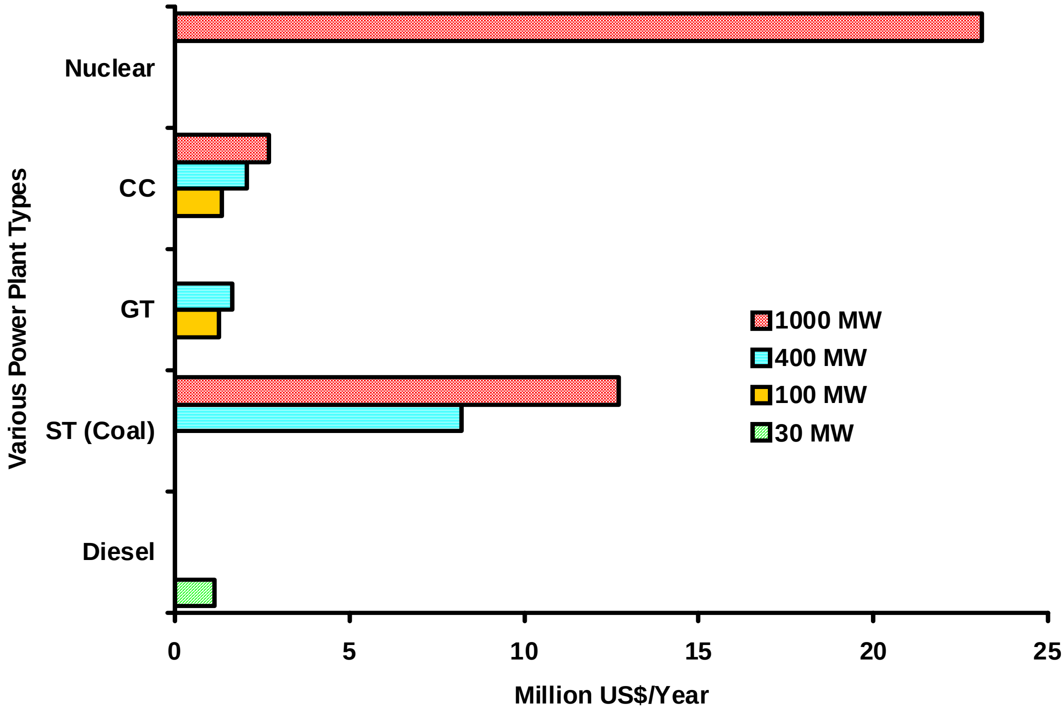
6.5.2.3 Comparison of operation and maintenance costs

At current levels of fuel and capital cost, operation and maintenance costs affect the economy of a power plant in a limited manner only. They strongly depend on site specific and local conditions and account for approximately a tenth of the cost of electricity in a combined-cycle plant. The following figure illustrates the variable operation and maintenance cost of the different power plants. Variable costs for a combined-cycle plant are lower than for gas turbine plants, because these costs are driven by the spare parts of the gas turbine, which can be distributed over a larger output in the combined-cycle plant. The next figure shows the fixed operation and maintenance costs of the different power plants.



GT	Gas Turbine Power Plant
CC	Combined-Cycle Power Plant
ST (Coal)	Steam Turbine Power Plant (Coal Fired)
Diesel	Diesel Generator Power Plant
Nuclear	Nuclear Power Plant

Figure: Variable operating and maintenance costs for various power plants of different sizes



GT	Gas Turbine Power Plant
CC	Combined-Cycle Power Plant
ST (Coal)	Steam Turbine Power Plant (Coal Fired)
Diesel	Diesel Generator Power Plant
Nuclear	Nuclear Power Plant

Figure: Fixed operating and maintenance costs for various power plants of different sizes

6.5.2.4 Comparison of availability and reliability

Reliability is the percentage of the time between planned over-hauls where the plant is ready to answer the call, whereas the availability is the percentage of total time where power could be produced.

Availability and reliability have a big impact on plant economy. When a unit is down, power must either be generated in another power station or purchased from another producer. In each case, replacement power is more expensive. The power station's fixed costs are incurred whether the plant is running or not. In deregulated markets, reliability is crucial. Typical figures for the availability and reliability of well designed and maintained plants are detailed in the following table.

Type of Plant	Availability	Reliability
Gas Turbine Plant (gas fired)	88 – 95 %	97 – 99 %
Steam Turbine Plant (coal fired)	82 – 89 %	94 – 97 %
Combined-Cycle Plant (gas fired)	86 – 93 %	95 – 98 %
Diesel Generator (diesel fired)	90 – 95 %	96 – 98 %
Nuclear Power Plant	80 – 89 %	92 – 98 %

Table: Availability and reliability of generating plants

These figures are valid for plants operated at base load. They would be lower for peak or intermediate-load plants, because frequent start-ups and shutdowns reduce lifetime and increase the scheduled maintenance and forced outage rates.

6.5.2.5 Comparison of construction time

The time required for construction affects the economics of a unit - the longer it takes, the larger the capital is employed without return, since construction interest, insurance and taxes during the construction period add to the price of the plant.

A gas turbine in a simple-cycle application can be installed within the shortest time frame because of its standardized design. Gas turbines therefore help secure power generation in fast-growing economies. Additional time is needed for the completion of a combined-cycle plant. Combined-cycle plants can be installed in a two phase installation process, with the gas turbine running first in simple-cycle mode, and then in combined-cycle mode as the steam cycle becomes available. With this procedure, two-thirds of the power is available in the time required for a gas turbine installation. However, an outage is needed to convert the gas turbine power plant from simple-cycle to combined-cycle mode. The typical time required for a combined-cycle is around 20 months (varying according required balance of plant).

6.5.2.6 Comparison of electricity costs

Based on the data presented the following three figures show the cost of electricity with a range of ratings from 100 MW to 1000 MW. Utilization times used in these figures were corrected with reliability of the individual types of plant to reflect that a forced outage disturbs operation and causes start-up and shut down losses and additional wear and tear on the equipment

The following conclusions can be drawn from these diagrams:

The main competition is among combined-cycle, gas turbine and coal-fired steam turbine power plants. This situation is unlikely to change in the near future.

For small-to medium-power outputs (up to approximately 30 MW), a diesel generator power plant can be a genuine alternative. The high efficiency of modern diesel engines is slightly less than combined-cycle with the same rating. To achieve a higher output with diesel generators, however, multiple units must be combined. Therefore, the diesel-based plant loses its attractiveness for higher power ratings, because investment costs are higher than those for combined-cycle power plants without compensating for that fact by providing greater fuel flexibility.

Conventional steam power plants are suitable for use as coal burning plants operating in base-load (or occasional intermediate-load duty) if cheap coal is available or gas is expensive (e.g. LNG) for a combined cycle plant. Whenever gas or oil is fired in a power station, the combined-cycle plant is more economical than the steam power plant due to its higher efficiency and lower specific price. Modern combined-cycle plants are simpler, less expensive, and operationally more flexible than steam power plants.

The choice between a steam power plant and combined-cycle plant for intermediate-to-base-load applications is a question of fuel availability and price. If natural gas is available and cheap, a combined-cycle design will be selected. If coal is the fuel, a steam power plant will be chosen.

However, recent trends in fuel price development show a higher increase with natural gas and oil prices than with the coal price. It is expected that this trend will continue due to the high demand for natural gas and the approach of mid-depletion points in some exploitation regions. This gives coal fired power plants a good perspective for the medium term future in the power sector.

For short utilization periods (peaking units), the gas turbine is most economical. Gas turbines can serve as intermediate - or base-load units in countries where fuel is abundant at low cost. The lack of water consumption has made this machine popular in dry regions. The short installation time allows a customer to plan a new installation on short notice.

If all fuels are readily available at world market prices, gas fired combined-cycle plants are the most economical solution for intermediate- and base-load applications. This results in a limited environmental impact (small heat rejection or low water consumption). With clean fuels like natural gas, this technology also achieves low emissions.

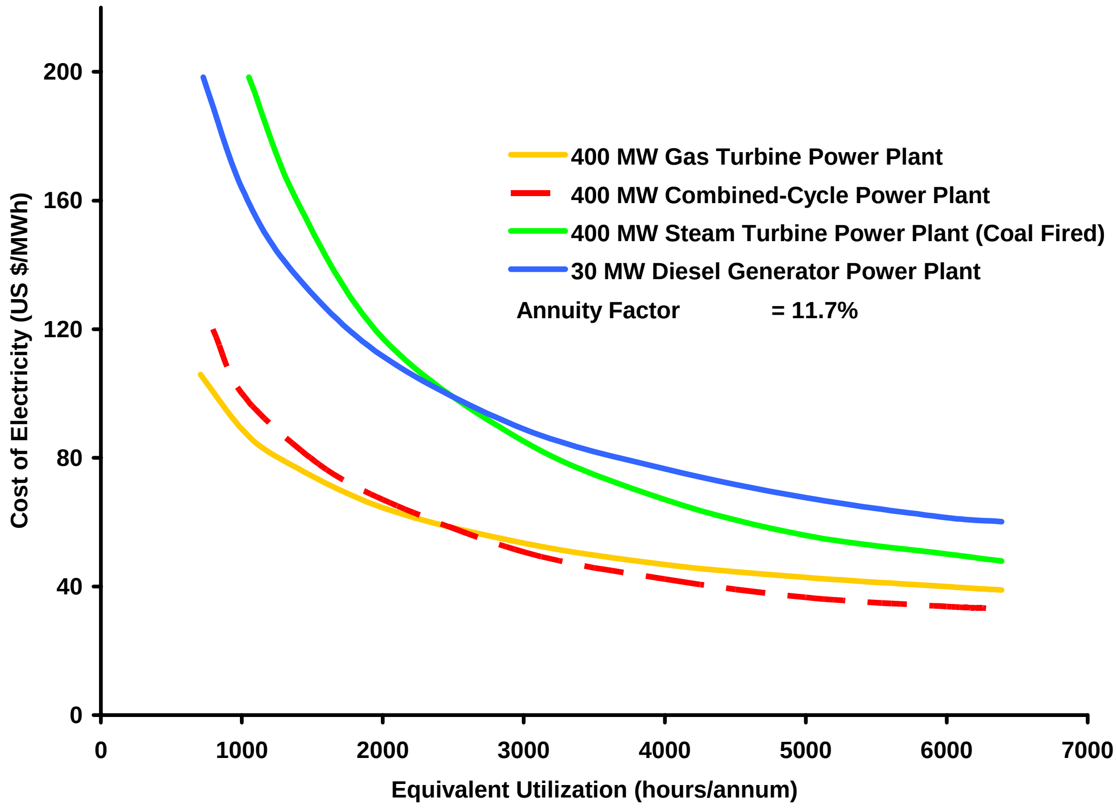


Figure: Dependence of the cost of electricity on the equivalent utilization time (small scale plants)

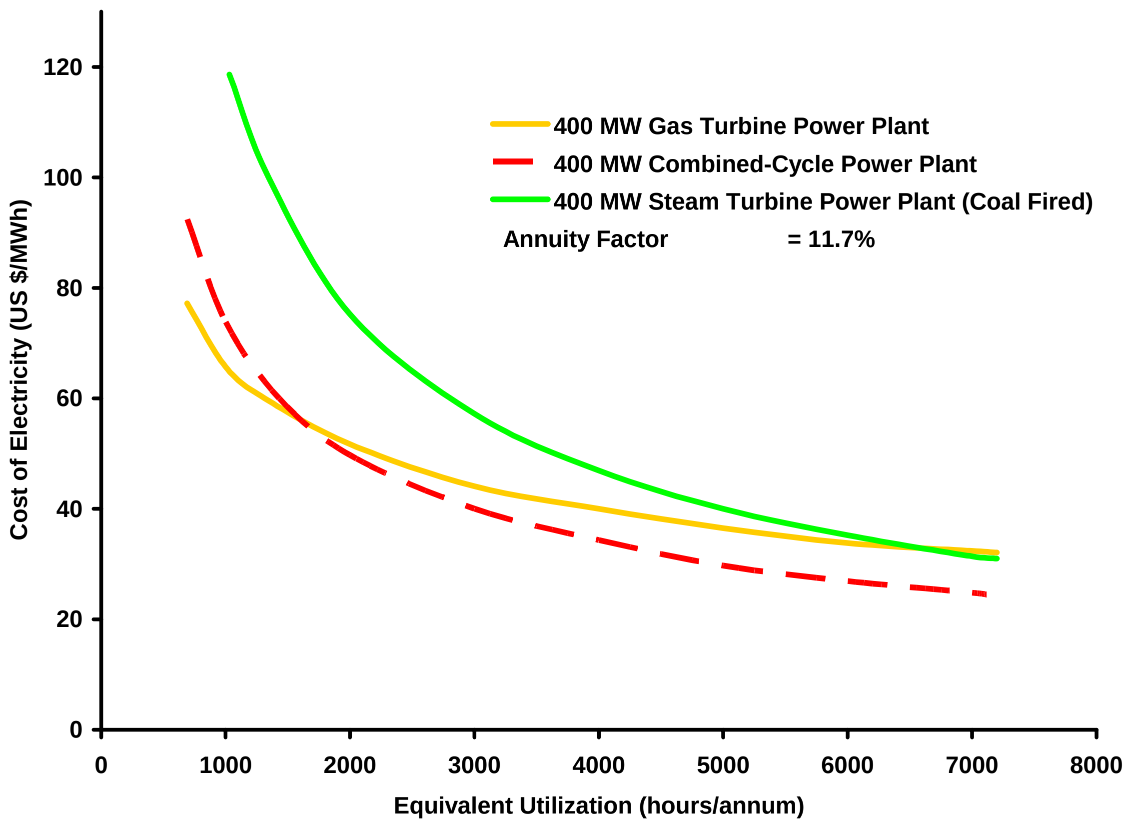


Figure: Dependence of the cost of electricity on the equivalent utilization time (medium scale plants)

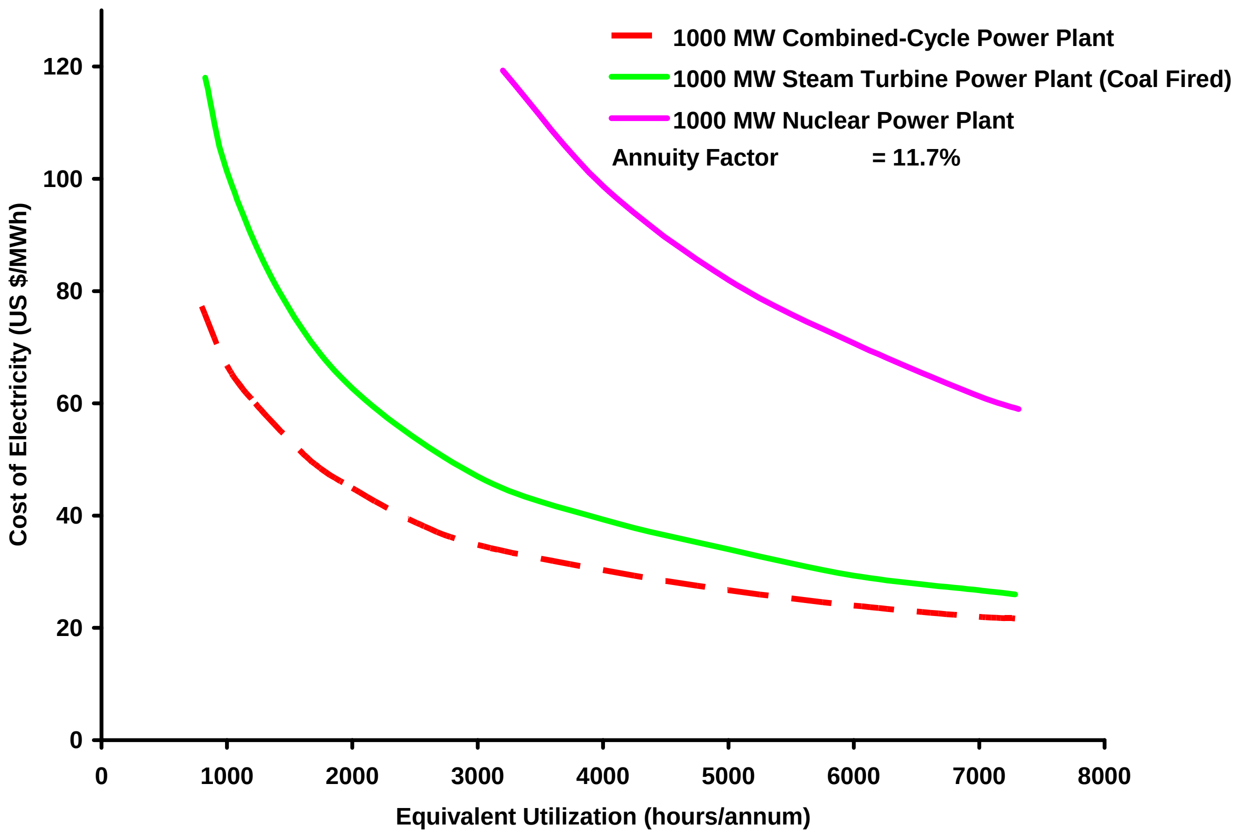


Figure: Dependence of the cost of electricity on the equivalent utilization time (large scale plants)

7 Priority action plan (PAP)

Key findings:

- Total private-sector investment in electricity between 1990 and 2002 in LA amounted to $97 billion, although this has been in decline in recent years.
- The reasons for the observed decline in private investment include badly designed economic reforms, economic crisis and bad business judgements.
- Investments in the electricity sector are dominated by the growth of power demand in Brazil.
- Brazil‘s electricity demand will increase by two-and-a-halftimes from 2000 to 2030, growing at an average annual rate of 3.2%. To meet this big increase, the country will need to invest more than $330 billion in the power sector, more than half in transmission and distribution networks.
- Cumulative coal investment of around $10 billion will be required in Latin America until 2030. Coal production in the region is expected to grow at 2.6% per annum, from almost 54 Mt in 2000 to 115 Mt in 2030.
- Cumulative investment needs in the Latin American gas sector are projected to total $247 billion, or more than $8 billion per year, over the period 2001-2030, amounting to 8% of global gas sector investment.
- Gas-sector policies will need to be integrated with electricity policies, as gas-to-power projects are the key to ensuring the financial viability of the gas chain.
- Investment in Latin America‘s oil sector is expected to be dominated by projects in Brazil and Venezuela. Total investment will amount to $336 billion over the period 2001-2030.
- On short to medium term (i.e. <15 years) new installations of power generation will be mainly based on natural gas and corresponding power generation technologies. The favourite technology will be highly efficient combined cycle gas turbines.
- There is a clear statement that actual priorities are given to push the economic growth of the region and that this priority is overruling any request of emission reduction from power generation.
- It is envisaged that in about 10 years emission reduction will be a strong subject of the region and refurbishment of power plants with regard to emission reduction facilities will become an issue.
- Because of the projected depletion of gas and oil reserves in about 30 years and the redundant availability of large coal reserves in the region, principally the clean coal based technology options PF combustion and IGCC may come to the fore in the longer term (>20 years).
- There are principally three main technology options for the fossil fuel fired power plant sector in LAC to be considered for the short to medium term (<15 years): combined cycle gas turbine technology, refurbishment of oil to gas fired power plants, retrofitting of emission reduction facilities.

- The Priority Action Plan (PAP) identifies the construction of two large CCGT power generation plants on natural gas in Central America with a regional perspective, lending impetus and viability to the power interconnection of the SIEPAC Project.
- According to information provided by the countries through the CEAC, the Central American power sector is expected to grow over the next two decades at a rate of approximately 5.5% per year.
- The Central American region would require 200 MW in new power plants starting in 2005. During 2010, 2015 and 2020, the integrated system would need the availability of an additional 1,300, 3,500 and 5,100 MW, respectively.

The Priority Action Plan shall identify CFT project opportunities in the LAC power sector which can be realised in the short term, i.e. <3 years. Identification of projects is based on the assessment of the investments needs of the sector, of the technological requirements and of the main options for power generation technologies for the short term period.

The identified project opportunities will be elaborated in order to demonstrate the technical, economic and environmental aspects of these possible investments. The associated “Project Description” shall enable first discussions with potential investors and financial institutions for project financing.

7.1 Potential for clean fossil fuels technologies’ (CFT) implementation in LAC

7.1.1 Investment needs in the LAC fossil fuel sector

The investments required in the LAC electrical sector are considerable, because it is not only necessary to replace systems that are ending their useful life, but also to modernize production and transportation equipment, and, more importantly, to install new equipment to cover the growth in demand and increase the coverage to unserved homes in rural sectors. Unfortunately, very few countries prepare and publish plans or prospects for their electrical sectors containing estimates of the necessary amounts of investment.

A general estimate for the investment costs in the LAC power sector can be taken from the following table:

	Investment (billion dollars)	2001-2010	2011-2020	2021-2030	2001-2030
	Total Regional Investment	339	440	558	1,337
OIL	Total	91	112	133	336
	Exploration and development	70	81	90	241
	Non-conventional oil	15	17	27	59
	Refining	6	14	17	37
Gas	Total	54	78	115	247
	Exploration and development	28	45	68	141
	LNG liquefaction	7	3	4	15
	LNG regasification	-	-	-	-
	Transmission	10	16	23	49
	Distribution	9	12	19	39
	Underground storage	0	1	1	2
Coal	Total	3	3	4	10
	Total mining	3	3	3	9
	new mining capacity	2	2	2	6
	Sustaining mining capacity	1	1	1	3
	Ports	0,4	0,3	0,5	1,2
Electricity	Total	191	247	306	744
	Generating capacity	86	111	120	317
	of which renewables	63	78	69	211
	Refurbishment	5	6	8	19
	Transmission	32	41	55	128
	Distribution	69	89	124	281

Table: Estimates of investments in the LAC energy sector from 2001 to 2030 (source: IEA)

7.1.1.1 Electricity

The electricity tariffs in many LAC countries allow the utilities to make profit. However, political uncertainties and legal framework instabilities in the region cause financial risk.

Attracting private investment can be challenging. The private sector, while in principle welcoming business opportunities in rapidly growing developing economies, will respond only, if it perceives a sufficiently stable and adequate legal framework and can expect returns high enough to compensate for the risks.

Many LAC countries initiated reforms in the 1990s, aimed at attracting private investment. The initial response was encouraging, but private investment declined rapidly after 1997. Total private-sector investment in electricity between 1990 and 2002 in developing countries amounted to $193 billion. Brazil and other Latin American countries attracted half of it. However, much of it was spent on existing assets that were privatised rather than on new projects.

Reasons for the decline in private investment include badly designed economic reforms, economic crisis or bad business judgements. Many private companies are now selling their assets in developing countries. The reasons for this are diverse and include poor returns on investment, loss of position in their home markets (notably in the case of US investors) and mergers and take-overs under corporate retrenchment policies (in the case of European investors). The result is a drastic reduction in the number of active international investors in developing countries. There are great uncertainties about when and to what extent private investment will revive and where the new investors might come from.

Another handicap for developing countries is growing constraints on their ability to borrow money in international markets. Traditionally, part of the power-sector funding has come from international lending institutions and export credit organisations. Funds from these sources are becoming less and less available. Competition between countries for global investment funds is likely to get fiercer in the future, underlining the need for developing countries to create attractive investment climates.

As Brazil is the leading economy regarding power generation the following paragraphs are specifically dedicated to this country highlighting the development of the electricity sector investment needs.

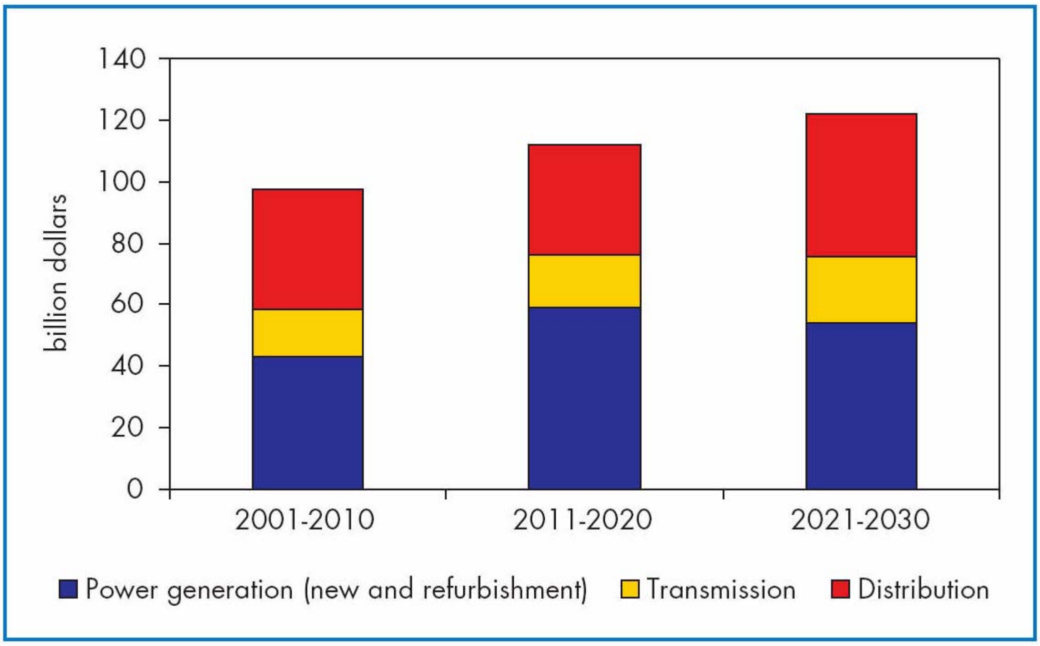
Brazil

Brazil‘s electricity demand will increase by two-and-a-halftimes from 2000 to 2030, growing at an average annual rate of 3.2%. To meet this big increase, the country will need to invest more than $330 billion in the power sector, more than half in transmission and distribution networks.

Installed capacity was 87 GW at the end of 2003, with 77% of it hydropower. Brazilian power plants produced 365 TWh of electricity in 2003, while imports amounted to 37 TWh.

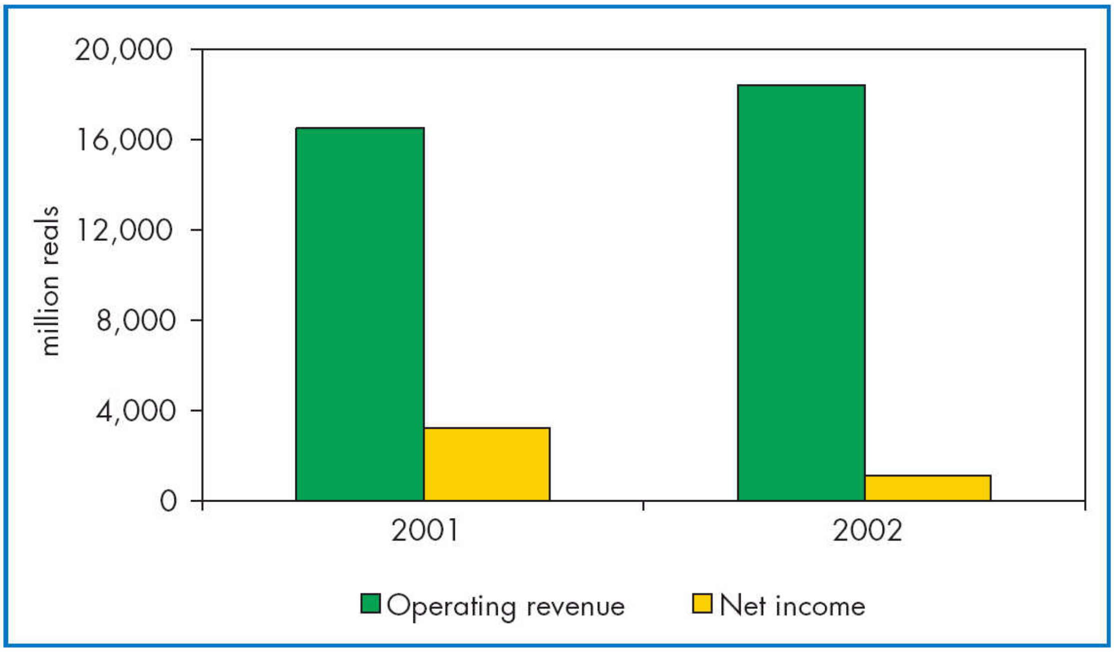
Transmission and distribution losses are among the highest in the world and account for around 15-16% of total domestic supply because of the long distances that characterise Brazil‘s power networks (with hydro resources located far from demand centres), old and poorly maintained systems with high losses and power theft.

While the distribution sector is 80% privatised, generation is still mainly publicly-owned. Eletrobras alone controls over 45% of the total Brazilian capacity through its subsidiaries. The previous Brazilian government planned to reduce the influence of Eletrobras by privatising its subsidiaries. The new Labour Party government gave up the plans of privatising the state-owned generators and intends to increase the role of Eletrobras as the major promoter of new large investments. The revenues of Eletrobras were over $6 billion in 2002 (about the same as in 2001) but net income fell dramatically (see Figure below) mainly because of the devaluation of Brazilian currency which increased the weight of debts in dollars.



Source: Eletrobras.

Figure: Electricity sector investment in Brazil, 2001-2030



Source: Eletrobras.

Figure: Eletrobras Operating Revenue and Net Income, 2001-2002

Brazil started deregulating its electricity market in 1995. A regulatory agency (ANEEL) was established in 1996 and a national transmission system operator was created in 1998. A wholesale electricity market was created in September 2000 and was put under ANEEL's authority in 2002. ANEEL has had a primary role in promoting the construction of new transmission lines, having awarded contracts for a total of more than 6,700 miles of lines since September 2000.

Tractebel Energia (part of Suez/Tractebel) became the biggest privately owned company in Brazil, with an installed capacity of more than 5 GW, following the acquisition of a former federal generator that was privatised (Electrosul). Several other foreign utilities (mainly US and European) are also present in the Brazilian electricity market.

In 2001, Brazil had a severe electricity crisis, caused by low rainfall for hydropower generation and the lack of investment in generation and transmission capacity.

Between 1990 and 2000, electricity production increased at an average annual rate of 4.6%, while installed capacity grew only by 3.1% per annum. As a consequence, reserve margins were low and the whole system became too dependent upon the annual rains. The crisis was solved through a rationing programme during a period of 10 months, which had a profound effect on the electricity sector and the Brazilian economy in general. The crisis highlighted the need for Brazil to diversify the fuel mix to reduce dependence on hydro.

Investment Perspectives

According to World Energy Investment Outlook 2003 (WEIO) investment in power generation over the next thirty years should reach $156 billion, most of which will go into the construction of 120 GW of new plants. Development of Brazil‘s transmission and distribution systems will require investment in the order of $175 billion. Insufficient investment in the transmission and distribution network was one of the causes of the electricity crisis in 2001 and this will be one of the major challenges during the next 30 years.

Issues and Implications

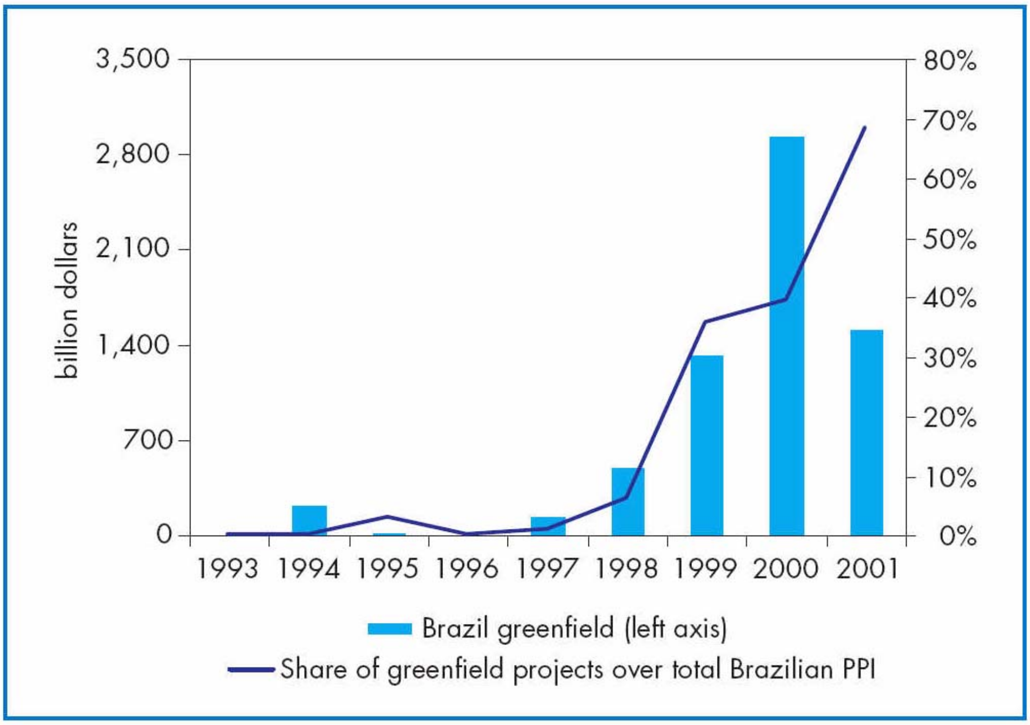
New capacity will be almost equally divided between capital-intensive hydropower and low capital cost gas-fired plant. Construction of hydropower plants will gradually slow down in order to reduce reliance on hydropower and because the remaining hydro resources are located far from the most populated areas, requiring huge investments in transmission lines. Environmental considerations may also have an impact on hydropower expansion, since much of the remaining potential is in the Amazon.

Private investors are unlikely to construct new hydropower plants, because of their high initial cost and long construction time. New hydro development is therefore likely to remain the government‘s responsibility. In the long term, investment in hydro will probably be more focused on the upgrading of existing plants, construction of medium-size plants or reactivation of small hydropower plants.

In February 2000, the Brazilian government launched the Thermoelectric Priority Program, which consists of a series of measures to increase and stimulate investment in thermal power plants, mainly CCGT plants based on preferential fuel prices and financing terms. Following the 2001 electricity crisis, the deadline for the programme has been extended to December 2004. Several of these projects are co-financed by the state-owned company, Petrobras, and foreign investors. The national development bank, BNDES, provides finance on favourable terms.

Whether enough gas-fired power plants will be built is very uncertain and will depend on the cost of natural gas, the development of the gas infrastructure system and the tariffs and contracts for the supply of natural gas. Natural gas investors seek long-term contracts to protect their investments. But in an electricity market dominated by hydropower, electricity prices will be highly dependent on the rainfall levels. The economic attractiveness of gas-fired power plants for foreign investors will depend critically on the type of contracts established.

Brazil was the world's largest recipient of private investment in electricity in the period 1990-2001. Private investment in new projects grew constantly in the late 1990s, following the privatisation programme, but declined in absolute terms since 2001 (see figure below).



PPI: private participation in investment.
Source: World Bank (2003e).

Figure: Private investment in greenfield projects in Brazil

The future growth of private investment in Brazil will depend on the capacity of its electricity and gas market to provide stable and reliable conditions. Much of investors' concern has to do with uncertainty about the import price of gas, mainly because of the exchange rate and the possible devaluation of the national currency.

Private investment progress in the distribution sector will be highly dependent on the regulatory framework. Difficulties in evaluating the risks linked to the progress of reforms and the lack of clear rules have been a cause of uncertainty and could adversely influence investments in the future.

7.1.1.2 Coal

Cumulative coal investment of around $10 billion will be required in Latin America over the period until 2030. Coal production in the region is expected to grow at 2.6% per annum, from almost 54 million tons in 2000 to 115 million tons in 2030. Country shares of production will remain constant, with Colombia still accounting for around three-quarters of the total. Primary energy demand for coal in Latin America is projected to grow at 2.3% per annum, from almost 23 Mtoe (33 Mt) in 2000 to around 44 Mtoe (70 Mt) in 2030. Exports will increase from 44 Mt in 2000 to more than 92 Mt in 2030.

Investment Perspectives

Latin America will need to invest said $10 billion in coal mining and port infrastructure until 2030 according to WEIO. Investments in Brazil will account for $600 million, or only 6% of the total.

Investments in coal mining will account for around 2.4% of the total world investment, or $8.6 billion. The new productive capacity that will need to be added is around 103 Mt, of which 61 Mt represents new capacity to meet demand growth and 42 Mt is needed to replace depleted mines. The corresponding investment needs will be $3.3 billion (39% of mining investment) for new capacity to meet demand growth and $2.3 billion (26% of mining investment) for new capacity to replace depleted capacity.

The remaining 35% of mining investment, or $3.0 billion, will be required for sustaining capital investment to maintain and increase the mine productivity.

The capital cost of new capacity additions rises over the projection period in order to reflect the increasing investment that will be required to improve Latin America‘s infrastructure, if it is to support a doubling of exports. The average cost of new port capacity is also above the world average, reflecting the higher cost of developing predominantly greenfield port infrastructure in Latin America.

Around 13% of the region‘s total investment will be required for coal export and import-handling facilities at ports, corresponding to $1.2 billion (around 10% of the world total for coal ports). This relatively large investment is due to the more than 100% increase in exports and to the currently sparse existing infrastructure, in particular in Venezuela, which will require significant new investment, if projections of export growth are to be met.

7.1.1.3 Natural gas

Investment in Latin American gas-supply infrastructure will grow steadily to meet rising demand and export volumes. Upstream investments will remain the largest component, but the development of transmission networks will absorb an increasing share of investment. Domestic demand and exports are set to rise significantly. Upstream financing will require large inflows of foreign capital. This might be problematic, depending on the degree of opening of the sector and on the political stability of the region. Cross-border pipeline and LNG projects will come on stream, if a clear and stable regulatory framework is set and co-operation among countries develops fruitfully.

<u>Investment Perspectives</u>

Cumulative investment needs according to WEIO in the Latin American gas sector are projected to total 247 billion, or more than 8 billion per year, over the period 2001-2030, amounting to 8% of global gas investment. Upstream development will absorb more than half of total capital flows, transmission and distribution pipelines accounting for another 36%. Investment in exploration and development was $2.1 billion in the year 2000. It is expected to rise steadily to $2.8 billion per year in the current decade and $6.8 billion per year in the third decade. Rising spending on E&D will be needed to sustain increasing production. Higher unit production costs will also add to capital needs, as a growing share of output will come from offshore fields.

More than $49 billion, or $1.6 billion a year, will be needed over the next three decades to build and expand cross-border pipelines and national transmission lines. The average annual capital expenditure is expected to increase over time. Spending will average about $1 billion per year during the current decade, compared with $700 million during the past decade. Investment will reach an average of $2.3 billion per year in the third decade, due to more technically challenging projects, with high per unit cost, and the faster expansion of the transmission network. The development of the domestic distribution network and underground gas storage will call for an additional $41 billion, or $1.4 billion per year. Some Latin American countries will invest heavily in LNG export facilities. Most of the LNG will go to the North American market and to importing countries in the region. Investment in liquefaction plants is expected to total $15 billion over the period 2001-2030.

Issues and Implications

One of the main uncertainties surrounding the pace of development of the transport infrastructure and, therefore, investment levels is the rate of growth of gas demand in the region, especially in Brazil. Regulatory uncertainties, gas pricing issues and the difficulties of introducing gas-fired plants have delayed thermal power projects over the past few years and might continue to do so in the future. Similarly, investment in LNG liquefaction plants will depend critically on the outlook for prices and demand in the key US market. Another crucial factor will be the relative economics of LNG shipments and cross-border pipelines within Latin America: LNG re-gasification terminals in the region may be a viable option in areas where it would be too costly to extend the transmission lines, such as Suape in Brazil. The Dominican Republic has recently started a 3 10^9 m^3 per year re-gasification terminal. Honduras and Jamaica are considering building re-gasification facilities too. LNG projects in Latin America, however, will have to be competitive with GTL projects and LNG projects outside the region.

Latin America has succeeded in attracting relatively large amounts of foreign direct investment in recent years, with most of it going to Brazil. Brazil succeeded in securing project financing for several large investments, including the $850-million Cabiunas gas-processing plant, the $1.2-billion EVM deep-water development and the $2.5-billion Barracuda and Caratinga oil and gas fields. Other countries, notably Bolivia and Argentina, had been successful in bringing in foreign investment in the gas industry, prior to the recent financial crisis in Argentina. But even before that, poorer countries struggled to attract investment in their upstream industry, because of political uncertainties, devaluations, banking crises, high unemployment and social unrest. Macroeconomic and political stability, together with moves to establish transparent, efficient and stable legal, regulatory and institutional frameworks governing the gas and other energy industries will be vital to reviving domestic and foreign capital flows. Gas-sector policies will need to be integrated with electricity policies, as gas-to-power projects are the key to ensuring the financial viability of the gas chain.

7.1.1.4 Oil

Projected oil supply trends call for growing investment in Latin America through to 2030. Investment will be dominated by conventional oil projects in Brazil and Venezuela, with heavy oil projects in Venezuela's Orinoco Belt region absorbing much of the rest. These countries will have to pay close attention to the fiscal and licensing terms and conditions on offer, if they are to attract the foreign investment that will be necessary to meet their ambitious expansion targets.

Investment Perspectives

Investment in Latin America's oil sector is expected to be dominated by projects in Brazil and Venezuela. According to WEIO total investment will amount to $336 billion over the period 2001-2030. Because of strong growth in production, annual capital spending in the region will increase sharply, from an average of $9 billion in the current decade to over $13 billion in the decade 2021-2030.

Brazil

Brazil is projected to require the largest amount of investment of any country in Latin America. The latest strategic plan of Petrobras, Brazil‘s state oil company, envisages domestic capital spending of $29 billion for the five-year period to 2007. The country is aiming to become self-sufficient in oil by 2006. Achieving this target is expected to depend largely on capacity expansion from high-cost deep water or ultra-deep water fields in areas such as the Campos basin north of Rio de Janeiro. Brazil‘s oil sector has been open to foreign involvement since 1998 and Brazil has held five oil-lease licensing rounds since then. The latest round of bidding in August 2003 attracted little interest from foreign oil majors. This is believed to be because of the disappointing results of recent exploration drilling, which yielded relatively small deposits of heavy oil in deep water. New policies affecting oil producers, such as domestic participation and procurement conditions, and a proposed change to the tax system have also undermined Brazil‘s attractiveness to foreign oil companies.

Venezuela

With the world‘s largest oil reserves outside the Middle East, Venezuela will remain the largest oil producer in Latin America throughout the Outlook period. Production of crude oil, LNG and extra-heavy oil, which was partially affected by the start of the nationwide strike, averaged 2.9 mb/d in 2002. PDVSA‘s (Petroleos de Venezuela S.A.) investment plan for the period 2003-2008 targets an ambitious increase in output to 5.1 mb/d. Capital spending of $43 billion, covering expansion of production from existing and new oilfields and from the Orinoco extra-heavy oil deposits, is budgeted.

The Venezuelan government has acknowledged the need for foreign oil companies to become involved in order to meet this target. Venezuela’s Hydrocarbon Law, which came into effect at the start of 2002, opened up the country‘s refining industry and exploration and development of light and medium crude oil to private investment, but limits private participation to 49%. It sets royalties at 20-30%. The Venezuelan Hydrocarbon Industry Association has claimed that these new fiscal arrangements need to be made more flexible in order to encourage foreign investment in mature and high-risk regions. This would help to compensate for the risk of output being capped by the government, as a result of OPEC production quotas. The last time this occurred was in April 2001.

Development of non-conventional extra-heavy oil, which the Orinoco Belt region contains in abundance, will account for a growing share of Venezuelan oil investment. Investment of $52 billion over the period 2001-2030 will be needed to meet projected production growth, the majority of which will go to projects based on partial or full upgrading of the region‘s extra heavy oil. Cumulative investment in such projects to date has totalled $13.3 billion.

Extra-heavy oil (8 to 9° API) can be produced like conventional crude oil without artificial stimulation. However, once at the surface, it must be diluted in order to pipe it to upgraders where it is converted into high-quality synthetic crude oil (typically 16° to 32° API, 0.07% sulphur). Venezuelan extra-heavy oil is also used to produce an emulsification with water known as Orimulsion which is marketed as a coal substitute for use in old coal- or oil-fired power plants. Orimulsion is excluded from Venezuela‘s OPEC production quota. Venezuelan production of non-conventional oil totalled 520 10^3 b/d in 2002. Output is projected to increase to 950 10^3 b/d in 2010 and 2.9 10^6 b/d in 2030. Most of this additional output will be synthetic crude.

Venezuelan non-conventional oil projects will be more resilient to periods of low oil prices than most other non-conventional oil projects because their supply costs are lower. But there are other risks associated with the political and economic environment within the country. These risks became manifest during the strikes at PDVSA in 2003, which severely disrupted production at all the Orinoco heavy oil projects.

There are currently four heavy oil upgrading projects in the Orinoco Belt (see table below). All of them are joint ventures between the state-oil company, PDVSA, and one or more foreign partners. Capital costs in each case were around $20,000 per barrel of daily capacity. PDVSA's business plan envisages a fifth project being undertaken before 2008.

The cost of upgraded Venezuelan extra-heavy oil is somewhat lower than in Canada, at an estimated average of around $8 per barrel. Upgrading accounts for more than half of the cost. Venezuela's lower costs arise largely from more favourable geological and climatic conditions. In particular, Orinoco oil is produced without thermal stimulation, because the oil-bearing formations are relatively hot (around 55°C compared to 8-13°C in Alberta). Higher ambient temperatures also make the oil easier to be transported once extracted and result in less harsh working conditions.

Project	**Partners** (with PDVSA)	**Peak capacity** (kb/d)	**Project life** (years)	**Start date**	**Capital investment** ($ billion)
Cerro Negro	ExxonMobil	120	35	2001	2.3
Petrozuata	ConocoPhillips	120	35	2001	2.4
Sincor	Total, Statoil	200	35	2002	4.2
Hamaca	ConocoPhillips, ChevronTexaco	190	34	2003	4.0

Source: IEA database.

Table: Orinoco Belt heavy oil upgrading projects

7.1.2 Technological requirements in the LAC fossil fuel power sector

Evaluation of the previous chapters clearly show that power generation in the LAC region heavily relies on gas and oil utilisation and corresponding power generation technologies such as gas and oil fired gas turbines and boilers with steam turbines. For decentralised power supply in remote areas diesel engines are suited best as long as the power interconnection network in LAC and the local power distribution network do not provide the requested coverage.

It is, however, a clear political objective of the region to expand the power interconnection network as well as the gas pipeline network in the actual decade in order to match the growing power demand of industry and population. Huge progress can already be recorded concerning the power coverage in densely populated areas where the supply of electricity almost covers >97% in average of the population.

The proven reserves of oil and gas in the region are supposed to last for about 30 years assuming actual demand. Realistic projections of an increasing demand will severely reduce this period of secure supply depending on the speed of the economic growth in the region.

On short to medium term (i.e. <15 years) new installations of power generation will be mainly based on natural gas and corresponding power generation technologies. The favourite technology may be highly efficient combined cycle gas turbines.

The request of the Southern Cone countries to refurbish their fuel oil driven power plants to natural gas fired plants is in line with this view. Oil will be preferentially used to satisfy the demand of the transportation sector and for exports to the United States. As the refurbishment of oil to gas fired power plants bears some technical problems which predominantly lie in the different flame characteristics of oil and gas flames, European companies may offer their technical expertise and support.

There is a clear statement that actual priorities are given to push the economic growth of the region and that this priority is overruling any request of emission reduction from power generation. Electricity price development is associated with the (more or less) liberalised energy markets in the region. In most cases subsidies to the power sector have vanished and the utilities have to produce the power as (cost-)efficient as possible. Introducing environmental protection measures in the power sector will disturb the cost balance of power production and yield immediately higher prices to the consumers. This distortion may hamper the economic growth of the region sustainably.

Nevertheless, as the economic development of the region will proceed, the requirement of emission reduction from power generation will be entrained by the population and probably also by the international community. It is envisaged that in about 10 years emission reduction will be a strong subject of the region and refurbishment of power plants with regard to emission reduction facilities will become an issue.

Summarising the above, there are principally three main technology options for the fossil fuel fired power plant sector in LAC to be considered for the short to medium term (<15 years):

- Combined cycle gas turbine technology for new large scale power installations
- Refurbishment of oil to gas fired power plants
- Retrofitting of emission reduction facilities at power plants

Untouched by this, there is still a market for conventional gas fired boilers or turbines for smaller size power plants or diesel engines for decentralised power generation.

According to the projected depletion of gas and oil reserves in about 30 years and the redundant availability of large coal reserves in the region there are principally also two clean coal based technology options to be considered for the longer term (>20 years):

- Super-critical pulverised coal fired power plants
- Integrated gasification combined cycle (IGCC)

The latter may become interesting concerning the use of already existent combined-cycle installations to which a coal gasification plant may be associated.

7.1.2.1 Refuelling of CCGT power plants

The refuelling of natural gas combined-cycle (NGCC) facilities from natural gas to coal syngas using gasification offers the benefit of using lower-cost, stable and plentiful coal as a feedstock and with a variable cost below price. A key motivation for refuelling is to recover impaired or strained capital investment. However, the decision for undertaking a conversion requires careful consideration of many factors that are linked to site suitability, financial, environmental, performance characteristics and other.

The two major components of a refuelling project are:

- the conversion of the combined cycle plant into a syngas power-block that can utilize low-BTU fuel and
- the design and construction of the gasification plant and its major systems.

Relative to the decision to refuel, the first major consideration is the accessibility and availability of coal supply. The site must allow for the logistics of coal delivery, offloading facilities, coal preparation and storage for coal, reagents and by-product slag and sulphur. The site will also dictate the level of integration possible between the gasification and power block. Although an IGCC plant will provide superior environmental performance compared to conventional direct combustion plants, new environmental permitting will have to be revised and public buy-in re-established.

Financial	**Environmental**
Treatment of residual value of NG plant	Permittability of coal vs. NG
Coal source & cost	Legacy permitting & public relation for NG plant
Base load demand vs. cycling	Site environmental recharacterization
Existing demand services arrangement	Revised air modelling
Byproduct sales	Local impact of coal byproduct transport
Revised contract services agreement	SCR/ammonia system capability
Existing NG supply contracts	Higher exhaust flow
Over-the-fence vs. on-the-books	15 ppm syngas & 25 ppm NG cofiring
Outage/interruption for conversion	Ammonia injection system
Site Suitability	Reduced exhaust temperature
Space for retrofit	Sulfur & trace metals impact on catalyst
Distance from gasification to GTCC	Accessibility for cleaning
Larger GT enclosure & BOP	Wash water treatment 6 discharge
Area for gasification plant	CO catalyst capability
Accessibility for GT modification	**Performance**
Accessibility for plant construction	Level of GTCC integration
Coal availability and accessibility	HRSG sizing
Materials logistics	Rebalancing of ST
Coal transport means & delivery	Generator capacity for higher output
Coal handling & storage	**Other**
Byproduct handling & storage	System Interconnect re-application
Reagent sourcing, handling & storage	Sulfur impact on downstream components
Site utilities	Reclassification of operating staff
Additional cooling water	Additional operating staff and crafts
Process water consumption	New HAZOPS procedures

Table: Factors to be considered in a decision to refuel an existing NGCC plant

The incremental capital cost for delivering a coal plant through a refuelling can be lower than a greenfield IGCC or conventional coal plant. The economic return for the project primarily will depend on the financial treatment of the existing NGCC facility and how much value must be carried into the refuelling project.

A large number of factors must be considered in a decision whether to refuel an existing NGCC plant. The majority of these are summarized in above table. These factors fall into five (5) major categories: financial/economic, site suitability, environmental, performance and other major considerations.

7.2 Clean fossil fuel technology project opportunities

7.2.1 Project Description: combined-cycle gas turbine project in Central America - ”Including natural gas in the Central American power interconnection”

7.2.1.1 Introduction

Contemporary development programs, whether national or regional, require attending to issues of resource sustainability, the environment, equity, the fight against poverty, free play of investment incentives and, in terms of energy, supply security for suitable energy inputs as required for the social development and economic growth of the nations.

In keeping with the spirit of the Lima Convention, the different forums for discussing the social and economic issues of Latin America and the Caribbean have reiterated the unpostponable need for these nations to integrate and seek solidarity in their many development efforts, in all possible areas of human advancement. This spectrum includes the necessary integration of all energy systems on the continent, a recommendation that perfectly matches the most objective function of the Latin American Energy Organization (OLADE).

In the case of the Central American region, thanks to the political will of its stakeholders, both the integrationist movement and the peace-making process have seen sustained progress in time, with evident signs of economic, social, technical, commercial, and environmental unification. As regards the energy sector, the regional power integration system or SIEPAC has become a fundamental bastion to ensure that effective economic growth strategies are carried out, and is one of the best regional instruments to guarantee efficient resource use.

In Central America, an unusual level of activity in the development and promotion of investments in almost all economic sub-sectors is foreseen. The growth of tourism, the promotion of mining, the formation of ecological corridors, the expansion of the “maquila” or assembly industry, the expansion of farming projects for export, modern service centres, and a particular interest in optimizing road infrastructure and communications, such as the possibility to establish an inter-oceanic dry canal and the optimization of port facilities, will demand a stable, high quality energy supply.

Furthermore, with the establishment of programs in most countries for the fight against poverty and to condone large amounts of foreign debt, it is clear that considerable financial resources will be spent on the promotion of basic services for the population, where energy will be the mainstay for future intensification of health and education programs, potable water supply, urban sanitation, local government building, mass housing projects, food security, and citizen security, as well as the essential activities of natural disaster prevention and recovery.

This dynamic panorama for the coming decades will surely surpass the expectations and timeframes of sectoral planning for energy, electricity and other sources. Therefore, it is important to review existing projections and alternatives, and to study, recommend and execute timely actions that will enable the region to achieve a state of security in energy supply, both in quantity and quality, in space and time, within the framework of economic advisability, sustainability and respect for the environment.

The above situation has led ministers of energy in the region to review the natural gas supply opportunities on the isthmus, associated with the promotion of existing decisions regarding the Central American Power Integration System (SIEPAC), both to attend to the eternal problem of supply and to determine opportunities for substituting liquid fuels and decreasing pollution, enhancing energy efficiency (especially in power generation), bringing new technologies on board, diversifying energy supply, substantially lowering the oil bill, and improving energy prices.

7.2.1.2 The Central American power interconnection

The length of time that interconnected power lines have operated among the countries of Central America make them the oldest in Latin America, and the experience gained in the region makes it an example to be followed.

Power interconnection began in this region in 1976, when the Honduras-Nicaragua line commenced operations. This interconnection was expanded to Panama in 1986, and currently operates at 230 kV with a 138 kV intermediate link in Costa Rica. El Salvador and Guatemala are not on this network, but are interconnected separately, and by the end of this year the Honduras – El Salvador line is expected to enter into operation, thus completing the interconnection among the seven countries.

The Honduras – Nicaragua line arose from a need for Honduras to sell its excess energy produced by the enormous *El Cajón* hydroelectric plant. As years went by, Honduras's demand not only filled but exceeded that plant's capacity, and the country had to ration its energy use, which was relieved by imports from Costa Rica and Panama.

Despite the limitations of current transportation capacity, existing interconnection operations have demonstrated to all countries in the region the advisability of maintaining and improving the system. In 1987, a study was begun to supplement the line with a 500 kV trunk link, giving rise to the project Central American Power Interconnection System (SIEPAC).

Figure: Existing power interconnections in Central America (source: Olade)

7.2.1.3 The SIEPAC project

The institutional basis for the SIEPAC Project is the Framework Treaty for the Central American Power Market, signed in December 1996 by the presidents of six countries of the region and ratified by their respective legislatures. In 1999, the *Empresa Propietaria de la Línea de Transmisión SIEPAC* was created as an anonymous company formed by the state power transmission companies.

The SIEPAC Project proposes two stages, to be executed in ten years. The first, to be completed in 2007, aims at strengthening the existing power systems by building a 1,802 km interconnection line from Guatemala, through each of the countries, to Panama, as well as extending the necessary sub-stations along the way. Joint system capacity will be 300 MW in any direction, and the investment for this initial stage will be $ 300 million. A joint financing arrangement, including the IDB, the government of Spain and other international entities, is being proposed. The second stage consists of building a second 230 kV circuit, provided the execution of new generation projects and the existence of sufficiently high demand to use the new lines to be installed.

The advantage of power interconnection in Central America is the opportunity for promoting a competitive power market regionally. This would ensure lower sales costs to service users, take advantage of the differing climates in each country and the fact that demand peaks do not coincide, as well as making it possible to reduce power reserves and develop more generation plants with a regional projection.

The future of the integrated power system in the region should be analyzed with a view to the ability to respond appropriately to energy demands in time and space over the coming decades. It is important and timely to expand the vision to joint generation, which contemplates including other diversified energy sources on the matrix, as well as using new technologies and the advantage of scale economies to ensure continuity in the supply of clean, affordable energy for all users.

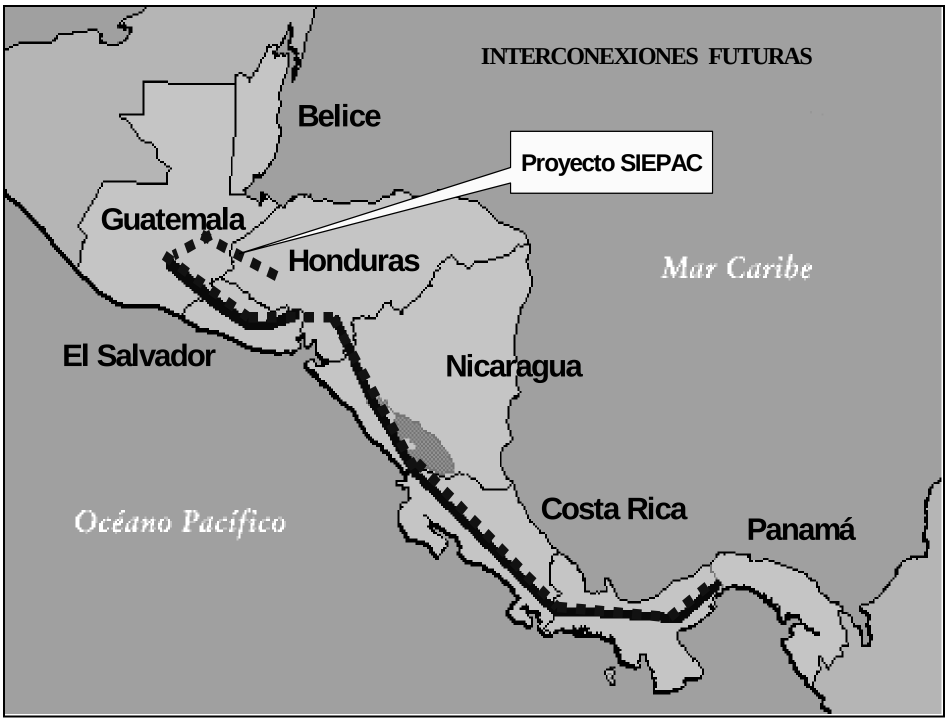


Figure: Locations of the SIEPAC Project in Central America (source: Olade)

7.2.1.4 Power sector diagnosis

According to information provided by the countries through the CEAC, the Central American power sector is expected to grow over the next two decades at a rate of approximately 5.5 % per year. At one end of the spectrum, Guatemala is projecting an average growth of 6.2 %, while at the other end, Nicaragua has established its power demand development at a yearly rate of 4.0 %.

In recent years, power system load factors have improved considerably, anticipating greater growth in the commercial and industrial sectors than in the residential sector, due to the economic development of the region.

Consumption times and patterns differ among Central American countries, and power consumption structures are dissimilar in each. This affects the configuration of load curves that, upon comparison, show evident differences in peak demand times. This situation is highly favourable for interconnected system operation, as is the different seasonal variation coefficient among countries, where future generation capacity could be achieved from diverse plants connected to the regional line, thus supplementing the need in each of the countries.

With regard to supply, the region currently supplies the power market with hydroelectric plants, thermoelectric steam plants consuming fuel oil, geothermal plants, diesel engines, gas turbines using diesel as a fuel, cogeneration, and a modest contribution from wind, biomass and solar power plants. Actually, an installed reserve capacity in the order of 27 % is anticipated and, under average hydrological conditions, hydroelectric plants will cover up to 49 % of all power consumption.

Current thermoelectric generation consists of plants consuming oil derivatives, being costly fuels for low-yield power plants. Although hydroelectric infrastructure plays an important role in the region, substantially modifying price structures, its share percentage has dropped considerably, while the oil bill grows continually in these countries.

The supply and demand analysis for the coming decades, carried out by OLADE, is based on the possibility of achieving a consolidated supply for the region through mechanisms that will favour the SIEPAC interconnection among the countries.

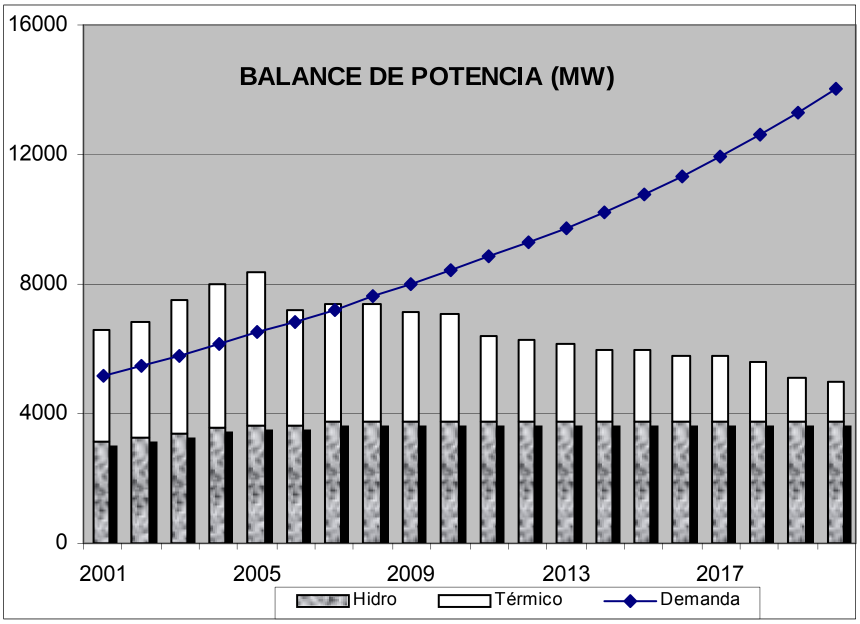
The hypotheses considered for determining energy requirements during the period under study, assuming conservative conditions, are the following:

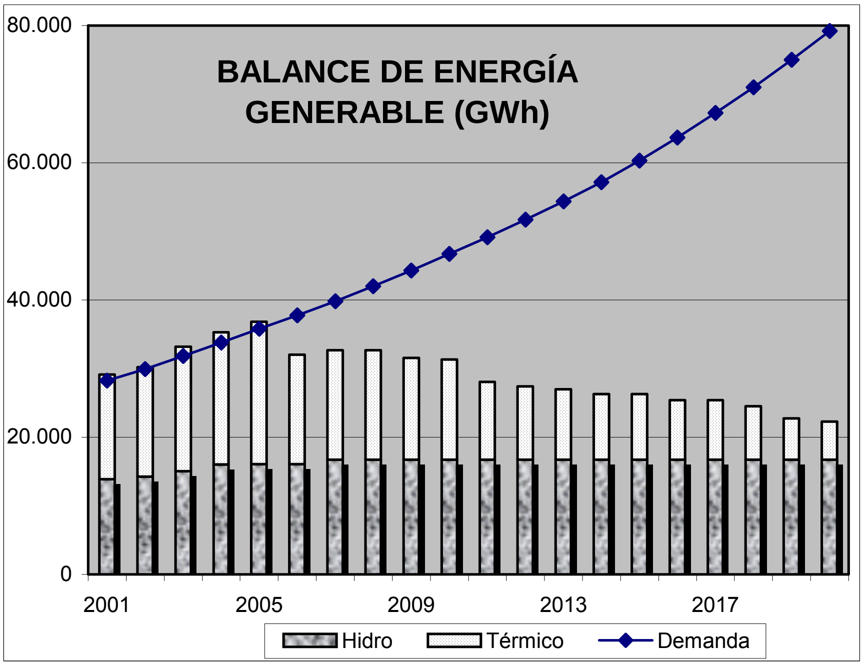
- Existing thermoelectric plants will behave similarly to 2000; that is, the plant factor remains constant over these 20 years; for hydroelectric plants, average water availability is considered.
- Both hydroelectric and thermoelectric plants currently under construction or fully defined to begin construction are considered as “existing” plants for the period under study.
- Thermoelectric plants having fulfilled their useful life are retired as of 2005, at which date gas supply may be available in the region.
- No power flow problems are assumed among the countries of the region, as the SIEPAC Project should be in operation by 2007.

According to the power and energy balance, the region currently has a reserve installed capacity of over 25 % and will only need new plants starting in 2005, although some countries will require new isolated generation plants prior to that date. In 2005, 2010, 2015, and 2020, the entire integrated system will need access to new facilities with a capacity in the order of 200, 1300, 4800, and 9005 MW, respectively.

A similar panorama is seen in energy supply, as the system only demands additional capacity in 2005, although some countries will need to install plants independently before that date. However, with the existing power interconnection, any national deficit problem can be overcome.

The graphs below show the power and energy balance for 2001-2020, based on currently available supply.





Hidro = hydro;Térmico = thermal; Demanda = demand

Figure: Power and energy balance of the SIEPAC Project for 2001-2020, based on currently available supply.

The second stage of the SIEPAC Project depends on developing generation projects of a certain size, which obviously can only be justified under a regional power supply system supported by large capacity generating plants at strategic points on the network, instead of a proliferation of small, isolated plants at a national level. This will allow for more efficient interconnected network operation, respond to environmental restrictions, and make it possible to channel economic resources from private financing agencies for implementation.

Presently, private investments demand a reduction in financial risks during the construction and operation of any generation project. This inclines decisions towards financing thermoelectric plants that, due to their operating costs, are preferable to operate with new technologies based on natural gas, which also complies with current environmental restrictions imposed on power generation projects.

The possible inclusion of hydroelectric plants, also with a regional vision, does not contradict the analysis offered in this document, as there is much space to be filled by power supply in the region, estimated at up to 9,000 MW of additional capacity by 2020. In this regard, the lack of interest shown by private investors for projects with long construction and recovery periods should be emphasized, as is the case with hydroelectric plants, as well as the execution difficulties implicit in the establishment of these works.

7.2.1.5 Analysis of the inclusion of natural gas

Interest in developing a natural gas supply system in the Central American region has lead to studies at different times, particularly motivated by the search for an alternative to compensate for continual variations and difficulties in importing hydrocarbons, and the unforeseeable execution of hydroelectric projects.

The possibility of including natural gas in the energy matrix of the Central American countries was reviewed during the nineties. There are three more recent preliminary studies: the first proposed an interconnection through a gas pipeline from Mexico to Central America;[11] the second, also through a gas pipeline from Colombia to Panama;[12] and the third, supplying LNG by methane tanker ships to five countries of the sub-region,[13] from Trinidad & Tobago or Venezuela. This last study omitted Guatemala, which had already signed a gas supply agreement with Mexico. Other references with information on this topic also show the interest that exists:

- Brown & Root, Inc. “Pan American Gas Pipeline” prepared for Arthur D. Little, July 1995.
- Estudios Energéticos Ltda. “Estudio Básico sobre la Utilización de Gas Natural de Colombia para Generación Eléctrica en Panamá” prepared for the Instituto de Recursos Hidráulicos y Electrificación de Panamá (IRHE). August 1997.
- Ministry of Energy and Mines “Gasoducto Mexico – Guatemala,” General Energy Department, Guatemala, 1998.

The above studies have focused primarily on natural gas use for power generation, and some have taken into account power expansion plans in the countries of the Isthmus and the possible installation of gas-driven thermoelectric generating plants, besides including potential gas consumption for the industrial and socio-economic sectors.

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[11] OLADE / ECLAC / GTZ Project, *Gaseoducto Regional México-Istmo Centroamericano*, 1998

[12] ENRON / TEXACO Project, 1998

[13] *Inclusión de Gas Natural en la Matriz Energética de Centroamérica y el Caribe*, OLADE, 2000

Natural Gas Consumption Market

It is estimated that the first shipments could begin early in 2005, taking into account the project maturation period, which should cover the definition and optimization of supply, engineering design, in-depth substitute market studies, costs involved in the change, quantification and certification of gas reserves, establishment of the business structure, finance and negotiation of purchase and transportation contracts and, finally, construction of methane plants and tanker ships. The reviewed consumption market covers the time period from 2005 to 2020.

The following hypotheses were used for including natural gas in consumption markets:

- Natural gas would enter the Central American market no earlier than 2005, through two points of entry located according to supply facilities, ease of interconnection, and possibility to diversify use.
- Refined oil products would be substituted by natural gas in the power, industrial, transportation, residential, and commercial sectors.
- In the power sector, it is believed that new installed generating capacity would be supplied by natural gas-driven combined-cycle thermoelectric plants. The conversion of existing oil derivative-powered thermoelectric plants was not considered, so this hypothesis responds to a conservative scenario with respect to natural gas requirements.
- In the industrial sector of the Isthmus, except for Guatemala, natural gas would replace 50% of all fuel oil, 40% for cement industry consumption, and 10% for other industries. In Guatemala, 80% of all fuel oil consumption would be substituted due to its larger proportion of energy-intensive industries, primarily metallurgy and cement.
- In the transportation sector, 10% of all diesel oil consumption will be substituted by 2005, reaching 50 % in 2020 with a linear growth rate.
- In the residential and commercial sectors, 10 % of all liquefied petroleum gas would be substituted by 2005, reaching 30% by 2020.

ZONE	2005	2006	2007	2008	2009	2010	2011	2012
A[1]	24	125	157	192	240	278	353	407
B[2]	9	56	68	95	133	167	229	262
Total	33	181	226	287	373	446	582	669

ZONE	2013	2014	2015	2016	2017	2018	2019	2020
A	451	512	566	624	685	755	860	938
B	304	341	380	440	484	536	585	647
Total	755	853	946	1,064	1,169	1,291	1,445	1,585

Zone A: Northern part of Central America : Guatemala, El Salvador and Honduras

Zone B: Southern part of Central America : Nicaragua, Costa Rica and Panama

Table: Natural gas demand projections for Central America (Million cubic feet / day)

Gas Availability

Potential natural gas suppliers to Central America are Venezuela, Trinidad & Tobago, Mexico, and Colombia. According to the latest information available, they have the following characteristics:

Venezuela. This is the country with the greatest proven gas reserves in Latin America and the Caribbean. It is presently not exporting gas. Ninety percent of its reserves are natural gas associated with oil, which would justify optimizing jointly the production of oil and natural gas to meet domestic needs and exportable levels of both liquid hydrocarbons and natural gas.

Venezuela plans to export 1,600 MCFD as of 2005, which could easily cover the requirements of the sub-region and provide additional surplus for export to other markets.

Trinidad & Tobago. The first major gas discovery was made by the Amoco Energy Company of Trinidad & Tobago in 1968, on the southeastern coast of Trinidad. Amoco currently provides 46 % of all natural gas used in Trinidad & Tobago. Most production comes from the Teak, Cassia, Banyan, Immortelle, and Flamboyant fields. The National Gas Company (NGC) was formed in 1975. Over the past years the NGC's gas suppliers have been Enron Gas, Oil Trinidad Limited and the British Gas / Texaco Consortium. The government is promoting domestic consumption of natural gas in different sectors.

On April 19, 1999, the LNG plant built in Point Fortin, belonging to the company Atlantic Liquefied Natural Gas (ALNG), began operations, with a production capacity of 3 million tons per year. It has in-port loading facilities for ships of 70,000 to 135,000 m^3 of capacity.

Production is exported to the USA and Spain. Cabot markets in Boston, USA, and Repsol in Spain. A second and third liquefying facility will supply LNG for Puerto Rico, Dominican Republic and the states of Maryland, North Carolina and South Carolina in the United States and, in the future, possibly for the northeastern market of Brazil.

Proven and probable reserves equal 27.4 x 10^{12} PCS (27.4 TCF). Over the next 20 years, 24.6 TCF will be used for domestic consumption and current LNG export commitments. Assuming that domestic demand grows by 5 %, the reserve required to cover domestic consumption would be 11.5 TCF, and 9 TCF would be needed for committed LNG exports (facilities I, II and III). Taking into account the 83.9 % yield of rich gas to marketable gas, an additional reserve of 4 TCF would be needed. Trinidad & Tobago could supply the demand of the countries in the sub-region, if it confirmed the existence of greater reserves or established some type of partnership with Venezuela.

Mexico. The domestic market development plan for natural gas in Mexico, presented by the Ministry of Energy,[14] shows that domestic demand will grow by over 100% in the next ten years, from 4,418 MCFD in 1999 to 9,508 MCFD in 2008. Imports will rise dramatically by 590%, from 186 MCFD in 1999 (4.2% of the demand) to 1,094 MCFD in 2008 (11.5% of the demand). If no additional reserves are brought on line, current reserves will be depleted by 2020 and imports will grow substantially as of 2008. Forecasts for Mexico do not contemplate exporting to Central

[14] Ministry of Energy, *Prospectiva del Mercado de Gas Natural 1999-2008*. Mexico, 1999.

America, but only minor exchanges with the United States.

Colombia. The domestic market development plan for natural gas in Colombia, presented by the *Unidad de Planificación Minero Energética* (UPME),[15] shows that the domestic demand will grow by 238% over the next ten years, from 478.5 MCFD in 2001 to 1,139 MCFD in 2010. In ten years, over 50% of current reserves will have been consumed. If no additional reserves are found, current reserves will be depleted by 2015. Depending on reservoir behaviour, there may be domestic market deficits by the start of the next decade. Export possibilities depend on exploration success in increasing reserves.

Apparently, the most probable sources of LNG supply for Central America would be Trinidad & Tobago and Venezuela. Trinidad & Tobago is the first country of the region to produce and export LNG, having begun in April 1999, and it already has a liquefaction plant in the process of expansion. Venezuela is currently working on the *Cristóbal Colón* project, which has not been developed yet. This review is based on LNG provision from that area of influence.

7.2.1.6 Olade's proposal for including natural gas

OLADE's goal of participating in the region with a proposal to diversify energy supplies to the power sector is based on the search for better options to optimize power generation in the region and support the Central American SIEPAC. Also, the proposal seeks to solve the eternal problem of timely energy supply, determine the possibility to substitute liquid fuels and decrease pollution, improve energy efficiency (especially in power generation), introduce new technologies (combined-cycle plants), diversify energy supply, substantially decrease the oil factor, and improve energy prices.

The review of the Central American power sector leads OLADE to propose the inclusion of two large power generation plants with a regional perspective, lending impetus and viability to the power interconnection of the SIEPAC Project. Furthermore, the advantages of including natural gas in the region, as reflected in the review, would make it possible to supplement the proposal by determining that the two plants would be natural gas-driven combined-cycle plants.

Considering that building a gas pipeline through the region is presently not feasible, due to the lack of a potentially attractive market, OLADE feels that the most probable source of natural gas would be through liquefaction and maritime transportation, thus eliminating restrictions on free placement of plant proposals. In this way they could be located in such wise as to optimize load requirements and power flows, and take advantage of power interconnection characteristics, enabling better operational conditions.

Among the criteria set forth, the following is a preliminary review of the advisability of introducing natural gas as an energy alternative in the Central American Region and identifying its competitiveness and advisability in relation to supplying liquid fuels and other expected impacts. This review assumes that the integrated system requires an initial regional supply as of 2005.

This review was done based on the assumption that the SIEPAC will be operational in 2007 and that by then it could include natural gas-driven combined-cycle power generation. The liquefied natural gas supply would be focused on two places in the region where both re-gassing plants and the power plants mentioned above would be installed. Electric energy would be provided to the

[15] Information provided OLADE by the *Coordinación de Hidrocarburos* of the UPME. Colombia, October, 2000.

SIEPAC line from these centres. Also, local gas pipelines would supply the major potential gas consumption markets in the industrial, transportation, commercial, and residential markets located within the area of influence of the point of supply.

Point of entry locations should be defined taking the following factors into account: port installations for receiving LNG, operational advantages of the power interconnection system, favourable conditions for installing the re-gassing and thermoelectric plants, and optimal natural gas access to markets for other consumption sectors.

7.2.1.7 Proposal feasibility

Price

The price of natural gas at wellhead may vary from its lowest limit, which would be the long-term marginal cost of production plus the margin that covers the cost of the resource, and the highest limit, which would be the "*net back*" of the opportunity price of substitution on the consumption market.

Since all natural gas transactions involve intensive use of capital in facilities, sales contracts set committed volumes and clauses with price adjustment mechanisms, generally based on substitute fuel baskets. The starting price is located between two limits set depending on negotiator ability and how eager one or the other side is to close the deal.

The price policy applied to natural gas in the area of influence of the study is as follows:

Venezuela. The Ley Orgánica de Hidrocarburos Gaseosos (LOHG) of 1999 and its regulation of 2000, establishes that the methane gas price is set by the Ministry of Energy and Mines (MEM) in dispatch centres by resolution. Production and marketing companies may ask the MEM to approve price agreements arrived at previously with consumers and distributors. Where there is no effective competition, prices will be set using simulation models based on the principle of economic efficiency, and the price will be freed when there is competition.

According to PDVSA information, the long-term marginal cost for gas production in Venezuela is $0.40 / MBTU for gas associated to oil production in the eastern region of the country; while for production from the western region the cost would rise to $1 per million BTU.

Trinidad & Tobago. As for this country's reserves, knowing that Venezuela's reserves are the largest in Latin America and the Caribbean, and in view of the fact that these two countries are geographically close to each other, it is logical to suppose that as soon as price competition is established, prices will be governed by the marginal costs of Venezuelan gas.

A natural gas price of $0.80 per MBTU at the liquefaction plant entrance (Trinidad & Tobago or Venezuela) was established for 2000. This price was related to average spot prices (FOB Caribbean) of diesel (N° 2) and fuel oil (N° 6 with sulphur contents of 2.0, 1.0 and 0.7 %).

The following table presents a summary of the liquid hydrocarbons data considered in the study:

	Unit	Crude oil	Diesel oil	Fuel oil
Average price FOB Caribbean [1]	$ / b	19.60	22.04	17.65
Maritime freight, insurance, port fees, storage, etc.	$ / b	6.86	7.71	6.18
Price CIF port of disembarkation	$ / b	26.46	29.76	23.83
	$ / MBTU		5.16	3.79

1. Source: Platt's Oilgram Price Report of 11 / 10 / 99, prices effective at 8 / 10 / 99

Table: Characteristics of crude oil, diesel and fuel oil

The assumption is made that, having oil price variations on the long-term international market, substitute energy sources will obtain their prices from competition, further favouring natural gas penetration.

In order to analyze the feasibility of substituting fuels for LNG, it has been proceeded to evaluate consumption, production and importing of diesel oil and fuel oil for each country, thus determining the weighted price for imported fuels.

Investments

The LNG supply to Central America from the area of influence (Trinidad & Tobago and/or Venezuela), involves including new infrastructure in the area, which consists of investing in gas field development and expanding the capacity of the following facilities: natural gas liquefaction, storage, in-port ship loading systems, methane tanker ships, and re-gassing plants, the latter at one of the gas points of entry to the area.

Investments in liquefaction plant and ship building take into account the capacity required to supply Central America and the Caribbean with LNG, making better use of available capacity.

For the purpose of this review, investments in gas field development will not be taken into account. Investment and operation costs for fields are recovered through natural gas prices at the liquefaction plant entrance.

Investments associated with re-gassing plant construction for the capacity planned at each point of entry are detailed in the following table:

Central America	Year	Capacity Mt n. m. / year	Investment 10^6 $
ZONE A	2005	3.44	241.70
	2014	3.44	241.70
ZONE B	2005	1.72	146.55
	2012	1.72	146.55
	2018	1.72	146.55

Table: Required capacities of re-gassing plants

Economic Analysis

The economic analysis of the liquefaction plant, maritime transport service and re-gassing plant used a 12% discount rate. The study covers the period from 2001 to 2020. Gas-driven power production operations will begin in 2005, and gas use will be promoted in other sectors.

Economic production analysis findings show that the long-term incremental price for natural gas at plant entrance would be $0.93 per million BTU, the incremental liquefaction cost would be $1.29 per million BTU of LNG, and the incremental price of LNG FOB port of embarkation would be $2.22 per million BTU.

The economic analysis of maritime LNG transportation operations to the two points of entry to Central America considered the joint supply for Cuba, Jamaica and the Dominican Republic, in order to take advantage of scale conditions, beginning with three methane tanker ships, with 125 10^3 m^3 of capacity each. The construction period for this fleet would be thirty months, at an investment of $540 million.

The following table shows the average long-term LNG tariff in the region:

Central America	Incremental Transportation Tariff $ / MBTU
ZONE A	0.44
ZONE B	0.40

Table: Transportation tariffs for LNG in Central America

The economic analysis of LNG supply is done on a per country basis, taking into account the volumes required for markets, the distances ships must go, the number of trips needed per year, and investments required in re-gassing plants. The summary findings of this analysis are shown on the following table.

7.2.1.8 Summary of the economic analysis findings for long term supply to Central America

RE-GASSING PLANT CHARACTERISTICS	Unit	ZONE A	ZONE B
Initial capacity	Mt n / a	3.44	1.72
Construction period	Months	18	18
Investment	10^6 $	241.70	146.55

ECONOMIC RESULTS	Unit	ZONE A	ZONE B
Price FOB LNG port of embarkation	$ / MBTU	2.22	2.22
Cost of maritime transportation	$ / MBTU	0.44	0.40
Cost of re-gassing process	$ / MBTU	0.56	0.66
Incremental natural gas price at re-gassing plant outlet	$ / MBTU	3.22	3.28

Tables: Re-Gassing plants characteristics and economic results

The substitution analysis took the opportunity import prices for diesel and fuel oil in the region. The weighted price reflecting the diesel / fuel oil ratio was determined taking into account the consumption structure in each country. These prices were applied to deficits proposed to be covered with natural gas. The analysis summary is shown in the table and graph below:

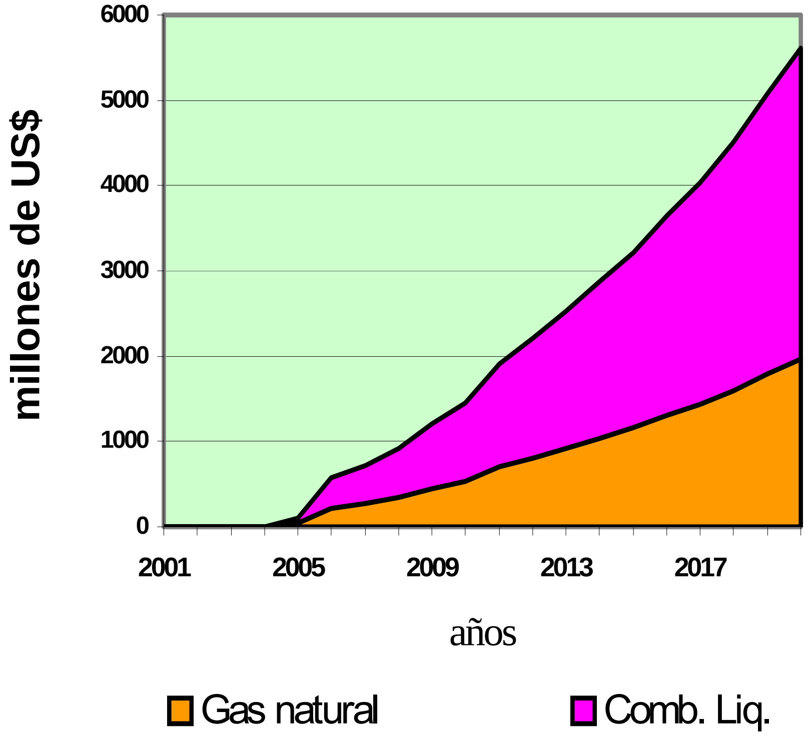

Figure: Summary of savings due to substitution

ZONE	A	B
Gas price at re-gassing plant outlet $ / MBTU	3.22	3.28
Weighted price of liquid fuels $ / MBTU	5.65	5.87
Unit savings due to substitution ($ / MBTU)	2.43	2.59
Total savings in 16 years (10^6 $)	6,755	4,684
Total discounted savings in 16 years (10^6 $)	1,355	902

Table: Fuel expenditures

7.2.1.9 Conclusions

The countries reviewed, except for Guatemala, cover all energy demands of their markets through liquid fuel imports and hydroelectric power generation. If no other projects are implemented on a national scale, the region would require 200 MW in new power plants starting in 2005. During 2010, 2015 and 2020, the integrated system would need the availability of an additional 1,300, 3,500 and 5,100 MW, respectively.

The projected hydroelectric potential will face implementation difficulties, due primarily to State limitations on direct execution and the lack of private sector interest in this type of investments. However, the supply deficiency is so large that any hydropower development will always be insufficient to meet expected demands.

The region's efforts were crystallized through studies for the SIEPAC Project, the creation of the *Comisión Regional de Interconexión Eléctrica* (CRIE), the *Ente Operador Regional* (EOR), and the *Empresa Propietaria de la Línea de Transmisión SIEPAC*. This decidedly seems to be the best regional option and can only be supported by ensuring generation in a technologically modern, sustainable way.

Although during the 2005-2020 period, refined petroleum products are not partially substituted in the industrial and transportation sectors, and although the power deficit is covered with thermoelectric generation driven by fuel oil and diesel oil, imports of these fuels in the region would have an accrued incremental value of $26 billion at current prices. With the substitution, natural gas expenditures in the same period would only be $14.5 million, and savings from the substitution of liquid fuels for natural gas would be $11.5 billion.

As for the environment, substituting fuel oil and diesel with natural gas would cause a substantial decrease in atmospheric CO_2 emissions: 68 % in thermoelectric power generation and 61 % in industry. Likewise, it would reduce particulate emissions, and sulphur oxide emissions causing broncho-respiratory diseases and corrosion in industrial facilities would practically disappear. Furthermore, the environmentally sound management and operation of natural gas is substantially cleaner than that of refined petroleum products.

7.2.1.10 Recommendations

The proposal that OLADE presents in this document has special consequences for the region, the most significant of which is ensuring the power generation needed to meet the demands of these six countries over the coming decades. This would maximize joint system operations with the current and projected interconnected system (SIEPAC). The above would strengthen the SIEPAC organization in the region, lending it credibility and the capacity to respond to the investments required to implement the Central American power interconnection. In this regard, the following is recommended:

- The SIEPAC Project must strengthen its regional organization and take the initiative to make the proposal operational, encouraging private sector intervention and involving all possible strategic and financial partners, in order to strengthen the SIEPAC through the inclusion of natural gas.
- The SIEPAC, jointly with the appropriate governmental institutions, must start a schedule of contacts and meetings with the financial community, development agencies and the private sector, to discuss the details set forth in this proposal and begin decision-making on its particulars. For the above, it is suggested to organise an institutional mechanism to place this interest on the table and lead to a regional decision on the possibility of executing a project of this nature and attracting the interest of investors in the sector.
- As soon as possible, studies must begin as needed to detail the diverse matters set forth in this document and to carry out market studies, tax policy reviews, diagnosis and fiscal audits of generation infrastructure, price policy reviews, supply commitment projections, gas use diversification, comparative environmental impact assessments, and other required studies regarding the possibility of introducing natural gas in the region, taking into account

that the proposal motivating this document reduces the financial risks of the SIEPAC and the expansion of power supply for the region.

With its experience throughout the continent, OLADE is committed to collaborating with the organizations of the region in any supplementary reviews and studies that are required, as well as in the task of SIEPAC's institutional strengthening in the region. Furthermore, OLADE is willing to support the Central American institutions through an exchange of experiences with the countries of Mercosur, any necessary training for their personal, preparation of documents, and any international procedures required.

This project shall receive special consideration of the European Commission (EC) as it complies with several energy political issues of the LAC region and is located in Central America, a region where already an Association Agreement is in force which also tackles the energy sector.

The project will be presented and promoted to investors, financing organisations and politics in the upcoming events of the SESEM LAC Energy Conference in Mexico in February 2005 and the final SESEM Conference in Brussels in December 2005.

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http://www.unep.org/

9 Glossary and list of abbreviations

$ - US Dollar

€ - Euro, 1 € ≈ 1.30 $

AAU - Assigned Amount Units. One AAU represents the tradable right to emit one metric ton of CO_2-equivalent assigned under the Kyoto Protocol. The assigned amount is the total amount of greenhouse gas emissions that each country listed in Annex B of the Kyoto Protocol has agreed to not exceed in the first commitment period (2008 to 2012)1. From 2008, each Annex B country will have their assigned amount available in form of a quota - an upfront 5 year budget - in a national registry. AAUs are the core unit of the Kyoto Protocol.

ACC - new EU Member States since 01.05.2004

AFBC - atmospheric fluidised-bed combustion

Andean Community – countries of Bolivia, Colombia, Ecuador, Peru, Venezuela

Annex I Parties - The developed countries listed Annex I to the Convention a legally non-binding commitment to reduce their greenhouse gas emissions o 1990 levels by the year 2000.They have also accepted quantitative emission targets for the period 2008-12 as Annex B of the Kyoto Protocol. They include the 24 original OECD members, the European Community and 14 countries with economies in transition. Croatia, Liechtenstein, Monaco and Slovenia joined at COP-3, and the Czech Republic and Slovakia replaced Czechoslovakia.

Annex II Parties - The developed countries listed in Annex II to the Convention have a special obligation to help developing countries with financial and technological resources. They include the 24 original OECD members in 1992 (the time of signature of the Climate Convention) plus the European Community.

BAT - Best Available Techniques

b – barrel = 159 litres

bcm – billion cubic meter

b/d – barrels per day

BFB - bubbling fluid bed

BFBC - bubbling fluidised bed combustion

billion – 1,000,000,000 = 10^9 = Giga

bn – see billion

bkWh - billion kilowatt hours

BREFs - BAT Reference documents

BTU – 1 British thermal unit (Btu) = 0.252 kcal = 1.055 kJ

Caribbean Countries – countries relevant for the study: Barbados, Cuba, Grenada, Guyana, Haiti, Jamaica, Dominican Republic, Suriname, Trinidad-Tobago

Caribbean Community (CARICOM) - Antigua-Barbuda, Bahamas, Barbados, Belize, Dominica, Grenada, Guyana, Haiti, Jamaica, St Kitts-Nevis, St. Lucia, St. Vincent, Suriname, Trinidad-Tobago, Montserrat

CCT - clean coal technologies

CCGT – combined-cycle gas turbine

CEEC – Central and Eastern European Countries

Central America - Republics of Belice, Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama and Mexico

Certified emission reductions (CER) - Clean Development Mechanism projects should lead to incremental greenhouse gas emission reductions compared to an agreed emission baseline. These emission reductions are certified and the certified units may be used by Annex I (listed in the Annex B of the Kyoto Protocol) Parties to meet their targets. Ownership of the CERs generated from a CDM project would be subject to agreement between investor and host country Parties. Whether CERs can be further transferred is still under negotiation. However, they are de factor transferable because CERs are inter-changeable with units of the assigned amount.

CF – cubic feet = 0.028 m^3

CFBC - circulating fluidised bed combustion

CFT - clean fossil fuel technologies

CH_4 - methane

CHP – combined production of heat and power; sometimes, when referring to industrial CHP, the term “co-generation” is used

CIS – commonwealth of Independent States

Clean Development Mechanism (CDM) - The Kyoto Protocol establishes the CDM to allow emission-reduction projects located in the countries of non-Annex I Parties to generate certified emission reductions. The goals of the CDM are 1) to assist non-Annex I Parties in achieving sustainable development and in contributing to the ultimate objective of the Convention and 2) to assist Annex I Parties in meeting their targets. A part of the proceeds from the CDM will be used to create a new adaptation fund to assist developing countries adversely affected by climate change. Details on the functioning of the system will at the earliest be decided at COP6. CDM projects may be undertaken by private and/or public entities. Discussions are still ongoing about the different types of models for CDM investment that will be allowed.

CO_2 – carbon dioxide

Conference of the Parties (COP) - The COP is the supreme body of the Convention. It currently meets once a year to review the Convention's progress and to advance negotiations on various aspects of implementation of the Convention.

CPR - commitment period reserve

EC – European Commission

EIS – Environmental Impact Assessment Studies

ELCOGAS - in 1992, the environmental advantages of this coal gasification technology gained the support of the European Commission under the THERMIE Programme, as a targeted project. In addition, 8 major European utilities and 3 technology suppliers formed a consortium named ELCOGAS to manage the project.

Emissions Trading System (ETS) - Emissions trading is a scheme whereby companies are allocated allowances for their emissions of greenhouse gases according to the overall environmental ambitions of their government, which they can trade subsequently with each other.

ESPs - electrostatic precipitators

EU – European Union

Euratom - European Atomic Energy Community

FBC - fluidised bed combustion

FDI - foreign direct investment

FGD - flue gas desulphurisation

FTA – Free Trade Agreement

GHG – greenhouse gas

GDP – gross domestic product

GJ – Giga-joule, 10^9 J

Global Environment Facility (GEF) - The GEF was established by the World Bank, the UN Development Programme, and the UN Environment Programme in 1990. It operates as the Climate Convention's "financial mechanism" on an interim basis and funds capacity building, assistance for preparation of national communications and developing country projects that have global climate change benefits. Its role is to transfer funds and technologies to developing countries on a grant or concessional basis. With respect to national communications, the GEF meets the full preparatory costs in accordance with the terms of the provisions of the Convention.

Greenhouse gases (GHGs) - The main GHGs responsible for causing climate change are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The Kyoto Protocol also addresses hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

GTL - gas to liquid conversion (GTL) plants

GW – Giga-watt, 10^9 W

HFCs – hydrofluorocarbons

IEA –International Energy Agency

IGCC - Integrated Coal Gasification Combined Cycle

Intergovernmental Panel on Climate Change (IPCC) - The IPCC was established in 1988 by the World Meteorological Organisation and the UN Environment Programme. It conducts indepth surveys of the world-wide technical and scientific literature and publishes scientific and technical assessment reports that are widely recognised as the most credible existing sources of information on climate change.

International emissions trading (IET) - The Kyoto Protocol establishes a mechanism whereby Annex I Parties (listed in Annex B of the Kyoto Protocol) with emission commitments may transfer part of their assigned amount to other Annex I Parties (listed in Annex B of the Kyoto Protocol). The aim of international EuroKyoto Community is to improve the overall flexibility and economic efficiency in achieving the agreed Annex B emission target.

IPPC - integrated pollution, prevention and control

Joint Implementation (JI) - The Kyoto Protocol establishes a mechanism whereby an Annex I Party (listed in Annex B of the Kyoto Protocol) can receive emissions reduction units (comparable to CERs) when it helps to finance projects that reduce net emissions in an Annex I Party (listed in Annex B of the Kyoto Protocol) country. Some aspects of this approach are being tested in Activities Implemented Jointly (see AIJ).

JVs- joint ventures

LA – Latin America; Argentina, Brazil , Bolivia, Chile, Colombia, Ecuador, Paraguay, Peru, Uruguay, Venezuela

LAC – Latin America and the Caribbean (see above)

LNB – low NOx burners

LNG – liquefied natural gas

Kyoto Protocol - The Kyoto Protocol to the United Nations Framework Convention on Climate Change was adopted in December 1997. The Parties listed in Annex B of the Protocol commit themselves to reducing their collective emissions of the six main greenhouse gases by at least 5 %. Each country's emissions target must be achieved by the end of the period 2008-2012. Countries will have flexibility in how they achieve their emissions reductions. The so-called Kyoto mechanisms are Joint Implementation, Clean Development Mechanism and International Emissions Trading and these are designed to help promote an international market for emission reductions. The operational guidelines for all these mechanisms under the Protocol are still being elaborated, but concrete decisions in this area are expected at COP6.

m – million, 10^6

mb/d – million barrels per day, 10^6 b/d

MBTU - Million British Thermal Units

MCFD - million cubic feet / day

Mt – million metric tons, 10^6 t

Mercosur – countries of Argentina, Brazil, Paraguay, Uruguay

MW – Mega-watt of electricity, 10^6 W

MWh – Mega-watt hour, 10^6 Wh

N_2O - nitrous oxide

NGCC – natural gas combined cycle

Non-Annex I Parties - Countries that are not included in Annex I of the Convention -- developing countries. Non-Annex I Parties do not have any quantified emission limitation or reduction commitments under the Kyoto Protocol and have fewer specific mitigation and reporting obligations under the Convention compared to Annex I Parties.

OECD – Organisation for Economic Co-operation and Development

OLADE – Organizacion Latinoamericana de Energia (Latin American Energy Organisation)

OPEC – Organization of Petroleum Exporting Countries

PAP – Priority Action Plan, identifies most attractive CFT investment activities

PCA - partnership and co-operation agreement

PF - pulverised fuel

PFCs – perfluorocarbons

PFBC - pressurised fluidised bed combustion

PRENFLO - the Gasification Unit is based on the PRENFLO system, an entrained-flow system with dry feeding. The syngas is produced by reaction of coal with oxygen at high temperatures up to 1600ºC. The PRENFLO process is capable of gasifying a wide variety of fuel types, and qualities of coal, for the production of synthetic gas. The “design” fuel of Puertollano power plant is a 50% mixture, by weight, of local high ash coal and high sulphur petroleum coke.

PSA – production sharing agreement

R&D – research and development, especially in energy technology; may include the demonstration and dissemination phases as well

RGC - Regional Generation Companies

SCR – selective catalytic reduction of NOx

SNCR - selective non-catalytic reduction of NOx

SF_6 - sulphur hexafluoride

Sinks - Under the Kyoto Protocol, developed countries can include changes in net emissions (calculated as emissions minus removals of CO_2) from certain activities related to land-use changes and forestry. Calculating the effects of sinks (growing vegetation absorbs CO_2 from the atmosphere) is methodologically complex and still needs to be clarified. The IPCC recently prepared a special report on land use, land use change and forestry which should serve as a factual basis for discussions.

SIEE - Economic-Energy Information System

Southern Cone – countries of Brazil, Argentina, Chile, Bolivia, Paraguay and Uruguay

tcm – thousand cubic meter

TCF – trillion cubic feet = 10^{12} cubic feet = 28 10^9 m^3

ton – metric ton = tonne = 1,000 kg

TPA – third party access

TPP - thermal power plants

TW – Tera-Watt, 10^{12} W

TWh – Tera-Watt hours

WEIO – World Energy Investment Outlook 2003

WEO-2002 – World Energy Outlook 2002

WEO-2004 - World Energy Outlook 2004

UNFCCC – United Nations Framework Convention on Climate Change

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Directorate General External Relations
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EU Parliament: Committee on Industry, External Trade, Research and Energy
http://www.europarl.eu.int/committees/itre_home.htm

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Union for the Co-ordination of Transmission of Electricity (UCTE)
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United Nations Environment Programme (UNEP):
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11 Annexes

11.1 Annex 1 - Energy policies in LAC – a country by country analysis

11.1.1 Argentina

In early 2003 energy policy was subordinate to macroeconomic policies that were imposed to control the financial crisis and economic recession that Argentina faced principally between 2000 and 2003. In May 2003, Nestor Kirchner became President of the Republic, and faced the enormous challenge of improving the economic situation after two years of recession and financial crisis. Though the macroeconomic policies were able to stabilize the economy, the energy policy had only begun to be implemented by mid 2003.

It should be noted that the companies in the sector faced major changes during the crisis years (2000-2002) due to the policies adopted by the government during that period.

One of those policies was the creation of an oil export tax (20%) and the freezing of internal market prices. Due to this policy of low internal market prices, especially for natural gas, investment in both exploration and production fell.

As part of the measures for counteracting this drop in investment, a law was passed in January 2003 that allowed the repatriation of 70% of the income obtained by international companies, which, added to high international crude oil prices that augmented the profits of the companies, the previous policies were counteracted to some extent.

A second measure was taken in October when Congress passed a law that gave the government the authority to negotiate new contracts and pricing structures for natural gas and electricity until December 2004, in order to implement gradual price increases.

With respect to the electrical sector, it is important to remember that Argentina privatized the entire electrical sector and that the market is perceived to be efficient and competitive; private agents intervene according to the supply and demand, and the State participates through the regulator. In 2003, energy policy, as in the above case, was related to macroeconomics. Electrical rates were thus frozen and since the economy went from fixed to variable convertibility, all the devaluations of the peso with respect to the dollar were absorbed by the electrical companies. Some liquidated their assets and others withdrew from the market because of the losses they incurred. There has been no increase in investment in generating capacity despite the economic recovery.

In December 2003 the government announced plans to finalize the construction of the third nuclear power plant at an estimated cost of $300 million. Construction is planned to begin in 2004 and will be completed in 2008.

Finally, it should be noted that among the challenges for the coming year regarding policy matters is the promotion of gas and oil field development, given the disincentives the companies faced in previous years. This decision involves either price increases in the internal market with the accompanying high social and political costs, or perhaps the State will again undertake investment decisions. There is also the challenge of tackling industrial as well as urban air pollution through concrete programs, which will involve the design of plans to encourage the use of clean or alternative energies.

11.1.2 Barbados

Energy policy is oriented toward guaranteeing a supply of energy at the lowest possible price. Offshore and onshore exploration for oil and gas will be promoted in order to ensure that increased demand is satisfied. It also plans to increase refined products storage capacity, and for this $80 million will be required.

Alternative energy use and development is also encouraged; for this purpose a Centre of Renewable Energy Excellence will be created, and a wind power complex will be built.

A third policy objective is to encourage the use of natural gas, and plans exist for increasing the number of home users to 26,000.

11.1.3 Bolivia

The year 2003 was characterized by social upheaval and political instability that resulted in vagueness and indecision of the energy policies. Between January and December 2003 the Minister of Energy was changed 3 times, and after 15 months of his presidential term, the resignation of the current president, Gonzalo Sanchez de Lozada was made public in October. Though the social convulsion began due to the problems of the economic recession, these were exacerbated by lack of leadership in energy policy matters involving natural gas exports through Chilean or Peruvian ports. The energy policy guidelines established in 2003 included mass home and vehicle use of natural gas. The government set the goal of connecting 250,000 homes over a 5-year period by privatizing networks operated by YPFB and an increase in connections that would be the responsibility of the private sector. The goal of converting 70,000 vehicles to natural gas in 5 years was also set. Both plans have yet to be implemented. Policy objectives also included the industrialization of natural gas by building petrochemical plants and Gas to Liquids plants for natural gas. With regard to the former, the idea is to build a plant on the Brazilian border in order to export the products to that market. There are companies interested in developing it (Oderbretch, and others), though an increase in the amount of gas exported to be able to extract ethanol as the raw material for this project is still pending.

With respect to the Gas to Liquids plant, since Bolivia imports diesel to cover a 40% deficit in meeting the internal demand, it hopes to develop a plant to produce diesel from natural gas. However, since there are few plants in the world that have this technology, and large investments are required, this means that large markets are necessary in order for it to be feasible; feasibility studies are currently being prepared by the companies and consortiums involved.

A third policy objective is to expand natural gas export markets to neighboring countries and outside the continent. This includes increasing the amount exported to Brazil and Argentina. Also pending are the construction of a gas pipeline to Paraguay and the construction of a new gas pipeline to Argentina.

Finally, development plans include the Liquefied Natural Gas project that involves exporting natural gas through a nearby port (Chile or Peru) to Mexico and United States. However, the choice of the port is pending due to constant protests by various organizations opposed to exporting energy through Chilean ports; these led to the resignation of the president of the Republic in October 2003. To resolve this conflict a referendum to be held in 2004 was proposed.

Regarding the electrical sector, it should be noted that in April 2003 the executive issued a law to reorganize the sector, and the electrical sector, which was traditionally part of the ministry of hydrocarbons, was transferred to the ministry of economic development, thus eliminating a great potential for the development of integral energy policies.

The policy guidelines for the energy sector include extending the coverage of rural electrification by implementing alternative energy in rural areas and expanding electrical interconnection lines.

It is also planned to construct new thermoelectric generation plants for export of electricity. Thus, in July 2003, for example, the company, Red Electrica de España, announced a project for constructing a transmission line to link La Paz, Bolivia and Puno, Peru. This project seeks to provide cheaper energy to that part of Peru. In September 2003, a Brazilian company, Furnas, announced that together with Pan American Energy, it is studying the development of a mega project for the construction of a 2,000 MW thermoelectric plant and the construction of a 938-mile transmission line that would link Bolivia and Brazil.

11.1.4 Brazil

After becoming president, Luis Ignacio Lula da Silva included the establishment of a new energy policy in his agenda to give special importance to the electrical sector, since the country had experienced a major energy crisis with frequent blackouts in previous years. Thus, in July 2003, the Minister of Energy unveiled a new model for the electrical sector with the goal of guaranteeing the supply, stabilizing prices, and attracting new investment to the sector.

The proposed reforms included encouraging the utilization of hydroelectricity as a source of generation in order to diversify the sources and thus stabilize energy prices.

Another proposed reform was the creation of the “Electricity for All” program that was launched in November by President Lula in order to providing electrical service to 12 million Brazilians living in rural areas by 2008. The implementation of this mega project involves an investment of about $2.5 billion, 73% of which will be financed by the federal government and the remainder by local governments and companies in the sector. In this program the installation of infrastructure to transport electrical energy to homes (electrical connections) will be free for low-income families. Part of the policy also specifies that priority will be given to the use of local labour and the purchase of national equipment and machinery, which will be manufactured near the areas served as much as possible.

A third reform has to do with relaunching the Programa de Incentivo a las Fuentes Alternativas de Energía Eléctrica (PROINFA) [Program of Incentives for Alternative Sources of Electrical Energy]. This program was modified by Law 10.762 of November 11, 2003 to include greater participation by the States in the program, the encouragement of national industry and the inclusion of low-income families. Through this program for supplying energy, it is hoped to create a complementary instrument for hydroelectric generation for remote areas. In the Northeast, wind energy will complement hydroelectricity, since the rainy season is the inverse of the windy season. It will be the same case for the south and southeast using biomass, where the sugar-making season is the inverse of the rainy season. Under this program, it is hoped to double the share of renewable energies by 2006, and achieve 5.9% of the total production of electrical energy.

President Lula’s new policy for the hydrocarbon sector gave the domestic sector a greater participation in the development of gas and oil projects. Thus investments in these projects must include a percentage for purchasing goods and services from Brazilian firms. For example, the bidding competition for the construction of ocean platform p-554 requires that 70% of the parts be built in Brazil.

Moreover, it announced the design of a plan for expanding the use of natural gas by extending distribution networks to the residential, domestic, and industrial sectors, and for replacing fuel oil. A commission was established that included representatives of the Ministry of Energy and Mines, and the National Petroleum Agency. It is expected that a design for the final plan will be submitted next year.

The government's policy designs and goals include the expansion of Brazil's heavy crude refining capacity. Petrobras plans to invest $5.5 billion by 2007 to increase its refining capacity to about 1.9 million barrels per day. It was announced that the first step of this plan would be the construction of Brazil's first heavy crude refining plant with capacity for 150,000 barrels per day.

Petrobras plans to expand its oil and gas operations outside Brazil. In May 2003, Petrobras purchased an Argentine company, Perez Companc, and has gas and oil projects in other countries, including Bolivia, Cuba, Venezuela, among others. It should be noted that the exploration of new fields in Brazil is still part of the plans. It was announced that it has plans to invest about $34 billion in exploration over the next 4 years.

The challenges that will face policy design over the next year include the preparation of a new regulatory model for the electrical sector, which must establish proper coordination between the electrical sector and the other sectors involved, as well as a balanced legal framework for the operations of private and state companies, and the regulatory agency. There are many expectations regarding this process that could jeopardize future investments in the sector if it is not handled properly.

11.1.5 Chile

Chile's energy policy in recent years has provided strong support to the diversification of its energy supply, and special importance has been given to the consumption of natural gas, both for domestic as well as industrial use, and the generation of electricity. Thus, consumption increased more than 300% between 1991 and 2003. However, since strikes in Argentina (its principal supplier) during 2002 caused blackouts in Chile, the government hopes to improve the regulatory system, as well as the treaties signed with its neighbour, in order to ensure greater reliability of the supply, in harmony with the development and optimum use of power plants that collaborate to ensure a better quality environment in cities that have pollution problems. A first measure is that the government plans to ensure that all natural gas plants can be adapted to use oil as well, and plants must maintain a stock of oil in case the natural gas supply fails. This policy includes expanding energy integration with Argentina since it is expected that natural gas consumption will double over the next 4 years. The policies take into account the implementation of exploration and production projects outside Chile. Within this framework, in February of 2003, the Ministry of Finance approved the disbursement of $264 million in order to modernize Chile's refineries. Petroleos de Chile has projects in Argentina, Ecuador, Colombia, and Egypt.

A policy of the electrical sector is to continue the rural electrification program that began during the previous administration. The goal is to achieve rural coverage of 90% by 2006. It should be noted that currently Chile and Costa Rica are the countries that have the greatest electrical coverage in the Region. Another policy is the promotion of renewable energy to supply isolated rural communities that cannot be reached by electrical networks. A project was initiated in 2003 to supply electrical energy to 6,000 homes using solar or photovoltaic panels. Other projects that use wind energy are in the design stage. The promotion of renewable energy also includes the gradual replacement of diesel systems with hybrid systems based on renewable energy. Finally, one of the challenges in the coming years will be the structuring of a natural gas supply security plan that will meet the high rate of growth in energy consumption that it is expected to continue in the coming years.

11.1.6 Colombia

Colombia's energy policy for the electrical sector includes the goal of promoting the development of new energy technologies (wind), the identification and development of new electrical generation projects based on natural gas, and encouraging the connection of isolated municipalities to the interconnected system, and the construction of micro and small hydroelectric plants when resources are available.

Other objectives include the maintenance of a rate system that reflects the costs of efficient service. For this purpose, in March 2003, the Ministry of Energy and Mines announced an increase in electrical rates based on a new regulatory model.

A third goal involves the expansion of the energy market (interconnections) between neighbouring countries (Brazil, Venezuela, Ecuador, Peru, and Panama).

Finally, there is the implementation of regulations on nuclear energy and the creation of mechanisms for promoting private participation in expansion plans.

In the hydrocarbons sector, the main objective of energy policy is to increase oil reserves, since during the past ten years there have been no new oil discoveries and the reserves have dropped significantly over the past 4 years. This policy permits the production period of partnership contracts with the state company (ECOPETROL) to be extended, so that crude oil production can continue until the economic limit of the reservoir is reached. A second measure is to change from a fixed royalty of 20% to a variable one. Third, to reduce Ecopetrol's share in partnership contracts, and finally for contracts to give separate treatment block by block. Through these measures, the government hopes to position Colombia as one of the most competitive countries in terms of oil contracts.

Other policy objectives include reducing the subsidies on gasoline, strengthening the fight against fuel contraband, completing the deregulation process for the liquid fuel chain, in order to encourage new participants to become involved, as well as competition.

Finally, with regard to natural gas, it is expected that new tax incentives will be adopted to encourage the growth of the program for using natural gas in motor vehicles, and it is expected that the design of a plan for the mass distribution of natural gas in the industrial, commercial, and domestic sector will be initiated.

11.1.7 Costa Rica

Costa Rica's energy policy is based on four principles:

- Maintaining the role of the State in activities involving the development of energy resources.
- Ensuring that energy development contributes to maintaining social, economic, and political equilibrium.
- Safeguarding national sovereignty by avoiding excessive external dependence on strategic inputs and
- Maintaining and improving the quality of life of the people

These principles highlight to the fulfilment of the principal objective, which is to "Ensure an adequate supply of energy for the integral development of Costa Rican society."

The policy for the hydrocarbons sector is to promote investment in exploration and production, to maintain strategic petroleum refining and storage capacity, to study the advisability of integration with the countries of the region, and to include natural gas as an energy source in the national market.

In the electrical sector, it will promote the manufacture and importation of equipment that uses renewable energy sources for electrical generation, and priority will be given to those that are environmentally clean. Moreover, it will promote the expansion of the networks through a program of rural and peripheral electrification, as well as the exportation of electricity to other markets, and it will continue the process of Central American interconnection.

11.1.8 Cuba

Energy policy is oriented towards achieving energy independence. It promotes oil exploration, principally offshore, through shared risk contracts between the State Corporation, Cubapetro, and private companies. Part of the energy independence strategy involves the development of renewable energy sources. It plans to continue supporting the use of biomass as the principal source of alternative energy. It is expected that renewable energy will be 40% of the total amount of primary energy that is produced in the next year.

11.1.9 Ecuador

Following drops in production by the state corporation (Petroecuador) that occurred over the past year, principally due to a lack of investment, the goal of hydrocarbon energy policy is to increase oil production. In April, the government announced plans to increase production to 613,000 Bbl/d by 2007. However, the challenge is to attract investment to achieve that goal, given the problems faced by the sector, which include the following: Opposition by Petroecuador workers to opening up jobs or projects to the private sector using partnership contracts, problems involving the VAT increase in 2001, and the promulgation of a new hydrocarbons law, which raises serious doubts about the sector.

In the electrical sector, energy policy has been oriented in recent years toward the privatization of its units, but there was strong opposition from the workers as well as local governments. In July, the shares of the company, EMELEC, were transferred to the municipal government of the city of Guayaquil, and a company, Distriguayaquil, was created.

The policy objectives also include continuing with rural electrification plans through the Fondo de Electrificación Rural y Urbano Marginal, FERUM, [Rural and Marginal Urban Electrification Fund] so that network expansion projects and the installation of small hydroelectric plants and photovoltaic systems can continue.

11.1.10 El Salvador

El Salvador began a process to privatize energy distribution that involved the dissolution of the national electric company, but the rest remains in state hands. It plans to privatize geothermal generation, however. Still pending in the policy guidelines is a reorganization of the institutional structure of the sector, and the separation of policy activities from regulation and control activities.

One of the principal policy guidelines is the promotion of integration plans to ensure the supply of energy. Efforts in this area include the current interconnection with Guatemala, the expected interconnection with Honduras, and the SIEPAC transmission line.

11.1.11 Grenada

A policy goal is the development and implementation of projects that use renewable energy sources such as solar, wind, bagasse, etc. Reforms are planned to make viable or encourage these projects in the medium and long term.

11.1.12 Guatemala

Its policy in the hydrocarbons sector is oriented toward encouraging the exploration and production of reserves and promoting regional integration.

Interconnections are promoted in the electrical like the hydrocarbons sector to ensure an adequate supply. In May 2003, an electrical interconnection agreement was signed with Mexico. It is expected that this project will begin operation in 2005. Another policy involves the expansion of generating capacity and it is expected that several thermal generation plants will begin operation in the coming years.

With regard to rural electrification, it will continue with the development of the Programa Nacional de Electrificación Rural (PER) [National Rural Electrification Program] in order to achieve 90% coverage in the coming years.

11.1.13 Guyana

Its energy policy is based on six objectives:

- To ensure an adequate and sufficient supply of electricity in the country for future economic development.
- To eliminate the need for fiscal transfers by reducing subsidies in final prices.
- To reduce dependence on oil imports
- To promote and increase the use of renewable energy sources
- To encourage the use of energy in a sustainable and environmentally friendly manner
- To promote the use of energy conservation practices through national programs.

11.1.14 Haiti

For many years, the energy policy has been oriented toward petroleum exploration but without success. Recently efforts have been directed toward promoting renewable energy and several international aid agencies have analyzed and promoted several energy sources, including wind, solar, methanol, organic waste, and others.

11.1.15 Honduras

Energy policy has recently been oriented toward promoting projects involving renewable energies and the dissemination of improved stoves, to reduce the pressure on the ecosystem due to the inefficient and unsustainable consumption of firewood for cooking, and to reduce contaminating emissions. It also hopes to develop wind and solar energy projects, and it is carrying out studies to determine their generation potential. Efforts have also involved campaigns for efficient energy use, and projects for promoting the use of biodiesel as fuel in motor vehicles. There are plans to develop an integral energy policy, supported by non-reimbursable OPEC funds; it includes the Renewable Energy and Energy Efficiency Policy Project that is expected to be ready for next year.

11.1.16 Jamaica

Energy policy is oriented toward ensuring a supply of energy at the lowest possible price. Every effort is made to diversify the sources of energy. To achieve this goal, it is considering the construction of a LNG terminal to import natural gas, and has held conversations with Trinidad and Tobago, and Algeria. However, the feasibility studies have yet to begin.

A second policy guideline is to continue promoting the development of renewable energies and there are plans to implement solar and wind energy projects.

Finally, the government has begun a program for saving and conserving energy in order to reduce consumption by the population by creating awareness and making better use of energy.

11.1.17 Mexico

After becoming President in 2000, President Vicente Fox undertook an energy policy based on the following principles: Energy sovereignty, secure supply, social commitment, modernization of the sector, greater private participation, orientation toward sustainable development, and commitment to future generations. Based on these principles, an energy policy was designed that includes the following main objectives and actions:

1. To ensure an adequate supply of energy.

   It plans to achieve a level of oil production of 3.87 million barrels per day by 2006, and also expects to reach a level of exportation of 1.85 million barrels per day, and produce 7,700 million cubic feet per day of natural gas.

   In May, President Fox announced two mega projects to be undertaken by PEMEX. The first is the development of a field in northeast Mexico where it hopes to discover reserves of about 18 billion equivalent barrels of oil. The second project is the development of 47 offshore platforms, as well as the construction of a pipeline, and separation and compression plants. With these projects it is hoped to achieve the goals set for 2006.

   In the electrical sector it plans to carry out a vertical separation of the activities of the sector, and also hopes to open it up to national and foreign investment, and establish a national transmission company.

   It also plans to promote the establishment of electricity sale/purchase contracts between generators and large users and to diversify the sources of energy by supporting the development of hydroelectric and coal-burning plants.

   The goal for rural electrification is to achieve 97% coverage of the population by 2006, and to promote generation based on renewable energy in isolated communities that have no access to the trunk network.

2. Policy of Institutional Change.

   By 2006, it expects to have a solid and adequate juridical framework for the energy sector that will guarantee the definition of public policy and sectorial strategy, with designs for new industrial organizational structures and operation for the different agencies in the sector.

3. To encourage the participation of Mexican companies in energy infrastructure projects

   It will facilitate the installation of storage and re-gassing terminals for liquefied natural gas. It hopes to have two of these terminals, one on the Pacific Coast and one on the Gulf Coast by late 2006.

   It plans to increase the number of natural gas connections to the United States market and achieve a capacity of about 500 million cubic feet per day by 2006. It hopes to double private investment in natural gas transportation and assign 10 new zones for distribution networks.

4. To increase the use of renewable sources and promote efficient use and energy savings

   By 2006, it hopes to achieve national energy savings equivalent to 2.5% of total consumption.

   It also hopes to double the use of renewable energies in subsequent years compared to the year 2000. For this purpose, it will install an additional 1,000 MW based on renewable energies such as solar, wind, small hydroelectric, geothermal and biomass.

5. To utilize sources of nuclear energy

   By 2006, it plans to have two nuclear units operating in accordance with the highest safety standards in order to reduce greenhouse gases and fulfil the Kyoto protocol

6. To be leaders in the prevention of hazards in productive operations

   It will increase the resources that are directed toward strengthening programs for the proper maintenance of facilities, pipelines and transport. It will implement 100% of the industrial safety system, and carry out 21 audits, evaluations, supervisions and technical inspections each year. It will also train 390 industrial safety specialists.

7. To be the sector leader in environmental protection.

   To achieve this objective, an environmental energy policy must be developed jointly with the Ministry of Environment that will be contained in a document on energy and the environment. It also hopes by 2006 to have indicators that are commonly accepted by both energy authorities and environmental authorities.

   It also plans to mitigate greenhouse gas emissions. By 2005, it hopes to develop a mechanism for validating emissions reduction projects that uses a solid and uniform methodology.

8. Development of scientific knowledge

   The Secretariat of Energy will promote the creation of a Center for National Information and Energy Studies. The purpose of this centre will be to develop methodologies and tools for strategic planning in the sector, and for carrying out multidisciplinary research and specialized studies of the energy sector.

11.1.18 Nicaragua

Nicaragua's energy policy is oriented toward promoting the permanent use of renewable and clean energy sources. The second important point of the energy policy is the promotion of the search for hydrocarbon reserves and the construction of gas pipelines in order to ensure the supply of energy. It has planned the construction of a gas pipeline to connect Mexico to Nicaragua. It also has plans for oil exploration, both offshore and onshore.

The policy also promotes competition and the systematic expansion of the electrical system. It has plans to privatize the state electric company.

11.1.19 Panama

Its energy policy objectives include promoting the development of renewable sources, increasing electrical coverage in rural areas, promoting regional integration with Central America, promoting energy saving, and defining subsidy policies that apply to the energy sector. It plans to increase electrical coverage to 95% over the next 10 to 12 years by creating incentives for the use of solar panels in remote areas and by encouraging the establishment of new hydroelectric plants. Two plants began operation in November 2003 (Guasquitas and Canjilones) and it hopes to incorporate a new one into the Bayano III project in order to achieve the established goals. With regard to integration projects, in October 2003, Panama and Colombia agreed to build an electrical transmission line and they hope to begin construction next year. The company, Endesa de España, is presently carrying out a study of an electrical interconnection from Guatemala to Panama to improve the countries' existing interconnections under the SIEPAC project.

11.1.20 Paraguay

Energy policy is oriented toward promoting and continuing integration with its neighbours.

It plans to develop a natural gas industry by building a gas pipeline between southern Bolivia and Asuncion, Paraguay. The project also includes the construction of thermoelectric plants, the first in Western Paraguay and the second in Asuncion.

Regarding the electrical sector, the policy will continue to centre on improving and developing its hydroelectric plants. In August 2003, Paraguay and Brazil has begun operating a new turbine in Itaipu, and they hope to operate a second turbine the following year to increase their capacity to 14,000 MW. Negotiations are also underway with the Argentine government to complete work at the Yacyreta plant so that the reserve will be 83 meters by June 2008.

11.1.21 Peru

Peru's energy policy on hydrocarbons has the initial goal of carrying out a detailed review of current regulations in the sub-sector in order to ensure that they are kept up to date and competitive. Following the drop in crude oil production in recent years, in May 2003, the Peruvian government adopted two methodologies for calculating royalties, and a company can choose which to use after preparing a commercial report. The first is based on different royalty percentages (0-5%, 5-20% and 20%) for different levels of production (0-5,000 b/d, 5,000-100,000 b/d and over 100,000 b/d). Under the second methodology, the royalty varies from 0 to 20% depending on the income and expenses incurred in the previous year.

The second policy involves the development of the Camisea field. It plans to sign contracts to permit not only the exportation of the reserves, but also the construction of pipelines. This project includes the sale of liquefied natural gas to United States and Mexico under a project called Peru LNG. By developing the Camisea field it is also hoped to supply generating plants in Lima and in northeast Peru, as well as large industrial users.

Regarding the electrical sector, it plans to develop an energy efficiency market and a program for expanding electrical frontiers. It is hoped that this expansion will increase the national average of electrification in isolated regions and villages.

The goal is to achieve an electrification coefficient of 91% by 2012, and to reach that goal, it plans to build 33 new transmission lines, and develop 243 small electrical systems and 60 small hydroelectric plants. It also plans to implement 123 electrical generator projects and install 120,000 photovoltaic panels and 124 wind generation plants.

Regarding the expansion of the electrical frontier, Peru has participated in an electrical integration project with Colombia and Ecuador as part of a movement by the Andean Community to create an integrated electrical market among its members. The goal of this agreement is an interconnection with Ecuador in order to export energy during the rainy season and import it during the dry season.

11.1.22 Dominican Republic

Its energy policy in recent years has been oriented toward improving the supply of energy by privatizing and deregulating the market, which involved a series of measures (subsidies and debts with the private sector, among others) that were in opposition to the market; as a result, in September 2003, it had to intervene and repurchase the recently privatized electric companies. However, despite that intervention, the situation and the energy crisis has continued due to the lack of funds for operations and the purchase of supplies.

11.1.23 Suriname

Its energy policy is oriented toward ensuring an abundant supply of energy. It has plans for attracting investment and increasing the generating capacity of the state electric company to reduce dependence on the company, SURALCO, which has a monopoly on generation; last year there was a major blackout that lasted 48 hours, and left the city of Paramaribo without power or alternative sources of supply. It also has plans to encourage the use of renewable energy.

11.1.24 Trinidad and Tobago

Trinidad and Tobago’s new energy policy seeks to transform a petroleum-based economy, as it was initially, into a natural gas based economy.

The first measure it hopes to apply is the restructuring and implementation of a new taxation system for the petroleum and gas sector, since previously the system was devised for a country with intensive oil production. It will continue developing and promoting the natural gas market. In August 2003, it signed a memorandum of understanding with the Republic of Venezuela for the construction of a gas pipeline between the two countries.

In June 2003, it approved the construction of the fourth LNG train, which it hopes will double its gas production and exportation capacity. Other industrial activities include the construction of a new ammonia and methanol plant, and feasibility studies have been initiated for the construction of a Liquid Gas plant and an Aluminium plant in 2004. It should be noted that next year it expects to complete the construction of one of the largest methanol plants with a capacity of 1.7 million tons per year.

The guidelines also include promoting the exploration of new fields and encouraging local participation. Next year it expects to grant 9 licenses for new exploration contracts.

The country's downstream activities are focused on increasing the value added from its natural gas production capacity. This involves participation at every stage of the value chain including shipping, re-gasification terminals, the pipeline system and even the market place. New petrochemical plants, such as CNC II ammonia and the Atlas methanol, among the largest in the world, came on stream over the period, and efforts are being pursued for the construction of an ethylene petrochemical complex with a minimum of four plants, and a gas refinery complex of at least five plants. The country is aiming at moving from first stage processing in the natural gas industry into second stage processing of petrochemicals. Not only are more petrochemical plants being proposed, but there are also plans to expand into areas of melamine production, nitric acid and urea ammonia nitrate.

In order to accommodate some of these additional petrochemical plants, including the aluminium smelter and the associated power plant, the Government is pursuing the development of a new 750-acre industrial estate at Union Estate in the South/Western part of the island. In general, additional sites are being explored for the location of the country's proposed energy-based industries. Trinidad and Tobago's energy expansion programme has propelled other associated infrastructural developments such as the LABIDCO fabrication yard that was designed for the construction of platforms and other equipment to support the increase in offshore activities, and to promote local participation in the energy sector. Such platforms would have been imported in the past.

In recognition of the need to develop its human capital to meet the needs of the expanding energy sector, the Government had established National Energy Skills Centres and an Institute of Technology, in the past. It is now considered expedient to move towards the tertiary stage in capacity building through the University of Trinidad and Tobago (UTT), with a major focus on energy technologies.

The construction of the aluminium smelter, which is predicated on the sourcing of alumina from both Jamaica and Suriname; the Trinidad and Tobago and Venezuelan partnership for an OEM facility and unitization of the contiguous maritime fields of the two countries; the proposed gas pipeline to the Eastern Caribbean region, coupled with the existing LNG exports to the Dominican Republic, are all part of its vision of a regional energy integration policy.

In the electrical sector the policy has been oriented toward increasing generating capacity in order to cover the future energy demands of the natural gas industrialization projects. It plans to increase transmission, sub transmission and generating capacity, to extend transmission and distribution lines, and to introduce renewable energy in order to support electrification in remote areas.

11.1.25 Uruguay

Energy policy is oriented toward guaranteeing the supply of energy. For some time the goal has been mass consumption of natural gas to cover 30% of its energy needs. It plans to build new gas pipelines to Argentina and Brazil, promote the development of natural gas networks, and convert vehicles to natural gas. The necessary technical regulations were prepared during the course of 2003. In recent years it has attempted to privatize units of the oil sector, but due to strong opposition from the workers this has been suspended. Other policy objectives include expanding the presence of its companies outside the country. Thus, the company, Administradora Nacional de Combustibles, announced in April 2003 that it would buy shares in the distributing company, Argentina Sol Petroleo, and also on the table is the management of the Argentine company, Petrolera del Conosur. Finally, it also has a policy for lowering energy costs in order to promote the competitiveness of the country. It plans to promote the re-conversion of thermal plants.

11.1.26 Venezuela

Energy policy for the internal market is oriented toward the development of the natural gas industry, the re-composition of crude oil reserves to increasing the proportion of light and medium oil, and the maximization of the participation of private national capital in petroleum investment projects. Its goals are to explore and develop free gas reserves, to support and encourage municipalities to build gas networks in the principal urban centres, to expand gas transmission systems, and to promote industrialization projects including liquefied natural gas (LNG) plants, petrochemical plants, and gas to liquid conversion (GTL) plants. Under this policy, PDVSA announced that between 2004 and 2009, it would invest $26 billion to increase the production capacity of its current producing fields, and to explore for natural gas reserves.

The policy guidelines include improving the productivity and competitiveness of the sector to make it more efficient. Thus in January 2003, the government decided to restructure the oil company, PDVSA, and divide the company into two regional operation units. The first is in charge of activities in Eastern Venezuela, and the other in the West.

With respect to the external market, the policy is oriented toward maintaining and strengthening OPEC's market stabilization policy, as well as decisive action and commitment of the government to respect the decisions of the Organization. Energy policy also includes promoting the regional and sub-regional energy integration processes in Latin America and the Caribbean. In July 2003, Venezuela and Ecuador agreed to facilitate government-to-government trade in LPG, diesel, naphtha, asphalt and lubricants, and also agreed that Venezuela would assist with the modernization of the state corporation, Petroecuador. Moreover, in April 2003, Colombia and Venezuela agreed to build a gas pipeline so that Venezuela could import gas until such time as it develops its own gas reserves, which would then be exported to Colombia through the same pipeline.

Finally, it should be noted that this policy includes the establishment of PETROAMERICA integrated by PETROSUR and PETROCARIBE, with the objective of joining together the state oil companies of Latin America and the Caribbean to invest in oil and natural gas exploration, production, and marketing. The basic premise is that the state company should be an ally of national companies, which, while respecting sovereign decisions and the legal framework of each country, can promote the development of the entire energy production and marketing chain.

11.2 Annex 2 – Structure of the LAC power sector – an analysis of the leading LAC countries

In the following the result of an energy sector analysis of those eight countries is presented that have the highest electrical consumption in Latin America and the Caribbean:

11.2.1 Argentina

The installed electrical generation capacity in 2003, including that of self-producers, was 30,599 MW, an increase of about 9.9% compared to the previous year 2002.

92,053 GWh of electrical power was generated in 2003, an increase of 9% over the previous year, but it has still not returned to the 2001 level. The wholesale electrical market, including the interconnected system, is supplied by the company CAMMESA. Generators have continued to participate in free competition, despite the grave macroeconomic crisis that began in 2002.

International electrical power transactions are important for regional integration. About 2,543 GWh were exported, and 7,578 GWh were imported, mainly from Paraguay. Both electrical imports and exports were lower than in 2002. Part of the electrical generation is supplied by Bolivian gas.

Regarding electrical power consumption, end users consumed 80,026 GWh in 2003, a 9% change from the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in dollars, were 0.044, 0.021 and 0.041 $/kWh, respectively. There was a slight recovery after the drastic drop in prices in 2002 due to the elimination of the exchange rate parity.

Regarding electrical service coverage, no estimates are available for 2003, but the latest report received by OLADE mentions that 95% of homes have electrical power service.

Following the drop in electrical rates due to the abandonment of exchange convertibility, the “pesification” of prices and the devaluation of the Argentine Peso, the Government maintained a strategy of not accepting proposals from several companies and agencies to increase rates, and authorized a loan to prevent CAMMESA from having to increase its rates due to seasonal variations in generation costs. These situations create uncertainty in the sector; however, it is know that the Government is making enormous efforts to normalize the situation gradually.

Other strategies have to do with the utilization of hydropower resources it shares with the two neighbouring countries. In 2003, the Presidents of Argentina and Paraguay set up a bi-national commission to establish a financial plan for finishing the Yacyreta hydroelectric project. Moreover, procedures are continuing for the construction of the Corpus Cristi hydroelectric project.

The supply of the natural gas necessary for generating electricity is leading the Argentine government to define strategies for importing a larger amount from Bolivia and to reduce its exports to other neighbouring countries.

11.2.2 Brazil

The installed electrical generating capacity, including self-producers, was 86,505 MW in late 2003, an increase of 4.9% compared to 2002. Self-generators represent 6,218 MW.

Regarding electrical power production, 364,846 GWh were generated in 2003, an increase of 5.6% compared to the previous year, which shows a large increase in the Brazilian electrical sector.

This country is very active in international electricity transactions; 6 GWh p.a. were exported and 37,141 GWh p.a. were imported, principally from Paraguay, but also from Argentina and Venezuela. Brazil is the largest importer of electricity in the region.

Regarding electrical power consumption, final users consumed 329,771 GWh in 2003, a 5.5% increase compared to the previous year. This shows a high level of economic growth, because programs for saving power and placing efficiency labels on electrical equipment were promoted at the same time.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in dollars, were 0.073, 0.038 and 0.083 $/kWh, respectively. Increases in the order of 40% compared to the same month in 2002 were reported, which are due basically to variations in the exchange rate.

Regarding electrical service coverage, it is estimated that 95% of homes have electrical service; 99% in urban areas and 74% in rural areas. In several countries, the data is from censuses that are not recent, and there is no breakdown of homes that obtain electricity illegally. The “Electricity for all” programs launched by the Government calls for universal electrical service in Brazil. The goal is to complete the program in 5 years until 2008.

One of the strategies of the Government was the establishment of a Chamber of Infrastructure Policies to promote the development of the energy sector, and decreed that rates be realigned and subsidies progressively reduced, until they are eliminated completely in 2007.

Another national strategy from 2003 comprises a draft law that regulates the distributor support program, the universal supply of electricity, PROINFA (Programa de Incentivo a Fuentes Alternativas) [Program to Encourage Alternative Sources] and the use of the CDE (Cuenta de Desarrollo Energético) [Power Development Account].

11.2.3 Chile

The installed generating capacity for public service was 9.969 MW in 2003. Including the self-generators it amounts to 10,738 MW, an increase of 2.2 % compared to 2002.

Regarding electrical power production, 45,055 GWh were generated in 2003, an increase of 3.2% compared to the previous year.

Regarding international electricity transactions, no exports were reported. Imports amount to 1,667 GWh, principally from Argentina. Several generators also depend on natural gas, a major share of it is imported from Argentina.

Regarding electrical power consumption, end users customised 41,894 GWh in 2003, a 2.7% increase compared to the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of November 2003, including taxes and expressed in US dollars, were 0.093, 0.063 and 0.097 $/kWh, respectively. On the average, these were 19% and 15% higher than in December 2002.

Service coverage of homes is estimated to be 97%, with almost 100% in urban areas and 80% in rural areas.

The Chilenean Senate approved a proposal by the Ministry of Economy and Energy to regulate transmission fees.

The Ministers' Council of the *Comisión Nacional de Energía* (CNE – National Energy Commission), approved the construction of the 480 MW Candelaria power generation project based on natural gas concession belonging to Colbun, a Chilean copper producer.

11.2.4 Colombia

In 2003, the installed electrical generating capacity in Colombia, including self-producers, was recorded at 13,653 MW, 1.4% less than the previous year.

Regarding the production of electrical power, 47,682 GWh were generated in 2003. This is an increase of 5.4% compared to the previous year. This figure was influenced by greater exports to Ecuador.

In March 2003, operation began on the 230 kV power interconnection between Ecuador and Colombia. The Regulators, CONELEC of Ecuador and CREG of Colombia, harmonized their respective regulations on transactions. On that basis, 1,120 GWh were exported to Ecuador, and total exports were 1,182 GWh, while 69 GWh were imported in 2003. The governments of Colombia and Panama approved a power interconnection line of 400 km length.

Regarding electrical power consumption, end users consumed 36,518 GWh in 2003, a 2.3% increase compared with the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in US dollars, were 0.092, 0.072 and 0.077 $/kWh, respectively. This is an increase of about 20% compared to the figures for the same month in 2002. The new rate structure will produce increases of about 8% over two years.

In 2003, it was estimated that 90.7% of homes were supplied with electricity, in urban areas the figure is 97.6% and in rural areas, 65.3%. The Ministry of Mines and Power submitted a draft law to supply electricity to additionally 1.5 million persons in rural and urban areas.

11.2.5 Cuba

The installed electrical generating capacity, including self-producers, was 3,959 MW in 2002. OLADE has not received reports of any changes in 2003.

Regarding electrical power production, 15,909 GWh was generated, an increase of 1.3% compared to the previous year.

Regarding electrical power consumption, end users utilized 12,469 GWh, an increase of 1.3% compared to the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in US dollars, were 0.105, 0.084 and 0.143 $/kWh, respectively. This means that there were increases, in dollars, of 5 %, 9 %, and 4 %, respectively, compared to December 2002 values.

It is estimated that 96% of homes have electricity, 99% in cities, and 87% in rural areas.

Priority has been given to rapid recovery power projects and promoting the electrification of irrigation systems to replace the fossil fuel driven irrigation pumps and thus to reduce the use of imported fuel. Efficient power use programs continue to be applied.

In mid May 2003, the 19th Latin American Conference on Rural Electrification was held in Havana, which demonstrated to participants from many countries on the American continent and from other continents, the notable achievements (increase of electrical coverage in households) in this area by the Cuban electrical sector.

It is important to take into consideration the strategy Cuba is applying in order to partially replace imported fuel in its thermoelectric power plants, through the use of national products from its limited heavy crude oil reserves.

11.2.6 Mexico

Installed electrical generating capacity for public service and that of self-producers was reported to 49,538 MW, an increase of 8.3% over the previous year. The largest cogeneration plant, 245 MW, was inaugurated in February 2003 to serve 38 industrial companies.

Regarding electrical power production, 203,735 GWh were generated in 2003, an increase of 1.2% compared to the previous year. In the recent years, the growth of industrial demand has been smaller.

Mexico exported 953 GWh to the States of Texas, California, and Arizona through existing interconnections, and to Belize in 2003. In the same year it imported 71 GWh from the United States. There had not been a positive balance in international electrical trade since 1996, i.e. Mexico imported more energy from US than is exported to neighbouring countries.

Regarding electrical power consumption, end users utilized 160,384 GWh in 2003, a 1% reduction compared to the previous. CFE (Comision Federal de Electricidad, National Electrical Utilities) projected that power consumption would increase by 75% by 2011, meaning that the national generating capacity has to be increased from 43,000 to 65,000 MW.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in US dollars, were 0.139, 0.07 and 0.081 $/kWh, respectively. This represents a small increase in the order of 1% for commercial and industrial users and a reduction of 4.6% for residential customers, compared to December 2002 prices.

It is estimated that 95% of homes have electricity, that is, 98% of urban homes and 86% of rural homes.

11.2.7 Peru

Installed electrical generating capacity in 2003 including that of self-producers was 5,970 MW, an increase of 0.6% compared to the previous year. The failed privatisations of 2002 created uncertainty to investors. However, the Camisea gas development created new incentives for the private investors resuming the expansion and modernization of electrical generation.

Regarding electrical power production, 22,926 GWh were generated in 2003, an increase of 4.3% compared to the previous year.

There are no important interconnections with neighbouring countries. In late 2004, it is planned to link the country to the power grid of Ecuador (Stage 1). Moreover, the Peruvian transmission company, REP, contracted the construction of a power connection line that will link Peru and Ecuador to a consortium composed of the Colombian company, Eléctrica de Medellín (EM), and the Peruvian company, Proansa. No date has yet been set for interconnection with Bolivia.

Regarding electrical power consumption, end users consumed 20,209 GWh in 2003, a 4.5% increase compared to the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of December 2003, including taxes and expressed in US dollars, were 0.076, 0.072 and 0.0114 $/kWh, respectively. These figures are lower than in December 2002 by 1.7 %, 1.6 %, and 0.6 %, respectively.

It is estimated that 76% of homes have electricity. Agencies are continuing their efforts to increase this percentage.

According to the regulator of the energy sector, Osinerg, generators will have to increase their efficiency to be able to maintain their share of the market once the Camisea project begins to offer gas for power generation.

The Mantaro hydroelectric complex that has a capacity of 1,008 MW belongs to Electroperu, and needs an investment of $1,000 million in the long term in order to continue being competitive.

11.2.8 Venezuela

Installed electrical generating capacity, including self-producers, was reported to 20,577 MW in 2002. No changes were reported in 2003.

Regarding electrical power production, 89,817 GWh were produced in 2003, an increase of 2.8% compared to the previous year.

No imports or exports of electrical power were reported, since the existing interconnections with Colombia are used only for contingencies, and the links with Brazil were used on a very low level.

Regarding electrical power consumption, end users utilized 62,477 GWh in 2003, an increase of 0.2% compared to the previous year.

Average internal electricity prices for commercial, industrial and residential customers as of May 2003, including taxes and expressed in dollars, were 0.079, 0.028 and 0.055 $/kWh, respectively.

Regarding the coverage of electrical service, it is estimated that 94% of homes have electricity.

The structuring of all the energy related agencies specified in the Organic Law of Electrical Service has not yet been completed.

To meet the increased demand at Falcon and Delta Amacuro, work will continue with the goal of placing four mobile units in service (a total of 20 megawatts) at the Dabajuro Plant, which is the result of a $12 million investment by ELEOCCIDENTE, a subsidiary of CADAFE.

Edelca resumed the operation of a turbine at its 10,000 MW Guri hydroelectric plant after replacing several parts to improve its efficiency.

Cadafe awarded Siemens-Westinghouse a contract for the supply and installation of turbines for the 450 MW Pedro Camejo combined cycle project in the state of Carabobo.

The Ministry of Energy and Mines awarded a contract to the distributor of Zulia, Enerven, for overhauling five 400 kV transmission lines in the western region, and authorized the state company, Enelven, to begin power generation at its 300 MW Termozulia thermoelectric project.

Edelca began operating the fourth turbine at the 2,160 MW Caruyachi hydroelectric plant located on the Caroni River. It also began conversations with PDVSA about supplying gas for a 450 MW power plant project.

The Corporación Andina de Fomento (CAF) [Andean Development Corporation] approved a US$ 100 million dollar loan for financing part of the Edelca transmission plan.

11.3 Annex 3 – Main players in the power sector in LAC countries

11.3.1 Supra-national organisations

11.3.1.1 OLADE – Latin American Energy Organisation

The Latin American Energy Organization (OLADE) is an international public cooperation, coordination, and advisory entity, essentially aimed at promoting the integration, protection, conservation, rational use, marketing, and defense of the region's energy resources.

OLADE brings together 26 member countries of South America, Central America, and the Caribbean and was created on November 2, 1973, as a result of the subscription of the Lima Agreement.

Objectives

Its objectives can be summarized as follows:

- Adopt political decisions to foster sustainable energy integration and development.
- Adopt political decisions to build up the capacity of the State as a standard-setting and regulatory entity for energy activities.
- Adopt political decisions to support Member States from third-party interference.
- Act as a forum for the consultation, analysis, and exchange of experiences to coordinate positions and strategies on energy issues.

Functions

Promote actions and take steps to achieve, among its member countries:

- The development of suitable energy policies for integration.
- A forum for exchange, dissemination, forecasting and strategic analysis, cooperation, and technical assistance.
- The identification and promotion of energy projects between Member States.
- Building up the negotiating capacity of Member States in energy.
- Promoting the development of new sources of energy, the protection and conservation of regional energy resources, and the development of clean technologies.
- Expanding energy supply in a rural environment.
- Promoting the transformation of the region's energy resources.
- Securing financial resources for energy projects of regional interest.
- Creating and developing the energy goods and services markets.

Working program

The three-year working program that is currently in force has been structured with the following programs:

- Energy integration

- Integration projects
- Forums on standard-setting
- Activities to build up standard-setting frameworks and regulations

Cooperation and training

- Increase horizontal cooperation activities
- Build up the technical assistance of the Permanent Secretariat
- Support the development of human resources of the member countries

Energy studies and projects

- Studies in energy technologies for the region
- Studies for fine-tuning regional institutional arrangements
- Sustainable energy development studies

Energy information

- Obtain, process and disseminate energy-economic information
- Compile and analyze legal frameworks
- Obtain, process, and disseminate information on environmentally friendly technologies

In view of the energy sector transformation that the majority of its member countries have undertaken to give the State a new role and to incorporate private-sector players, OLADE has started to incorporate new orientations and to open up its perspectives toward countries from outside the region and the private sector.

Associate Countries

Recently, the category of Associate Countries has been created enabling countries from outside the region's geographical area to participate in OLADE.

Regulatory agencies and entities

Furthermore, it is promoting the involvement of regulatory agencies and entities, whose activities are part of the new structure that transformation processes have set up for the region's energy sector.

11.3.1.2 CIER - Regional Integration Energy Commission / Comisión de Integración Energética Regional

Establishment and Functions

The Regional Integration Energy Commission (CIER) was created on July 10, 1964 on the basis of a proposition approved during the First Regional Electrical Integration Congress, then held in Montevideo, as an initiative of the Electric Sector Authorities. The Commission became operational in 1965. Since its beginnings, CIER enjoyed the warm support of the South American electric industries, and clearly reflected the strong need of collaboration among them.

At present times, CIER is a Non Governmental Organization, with diplomatic status recognized by Uruguay, comprising the electric utilities and organisations linked with the national electric sectors of the ten South American countries of Iberian roots, which are Member Countries, and three Associated Members.

The main objective of this non-profit international organization, established through its Statutes, is to promote and encourage the integration of the regional electric sectors, through actions whose goals are:

- greater efficiency of electric power utilities and governmental organisms in the Member Countries;
- assistance and technical cooperation between utilities and organisms;
- professional training at all levels and its interchange between utilities and organisms;
- transfer of knowledge, information, experiences and documentation in technical, economic and legal fields;
- projects development in a regional scope, especially considering the feasibility of electric international interconnections;
- orientation and coordination of general interest activities for utilities and organisms, including research and development fields;
- establish general specifications and technical standards accepted in all Member Countries;
- improve the utilization of regional technical personnel and technologies;
- promotion of regional statistic uniformity, strengthened through the operation of an up-to-date Data Bank;
- rational use of electric energy with the aim, among others, of utilities equipment and operation optimisation;
- promotion of electric power regional utilization with special concern about environmental problems.

To achieve its objectives, CIER uses different mechanisms, among which the following are the most important:

- Annual High Executives Meetings, to discuss subjects related to financing, relationship with national regulatory authorities, technical consulting services, equipment policies, utilities management, electric marketing, etc.

- Business Areas, with meetings each two years, to concern the studies or analysis of specific problems relating to the various fields of electric power industry.
- Special Seminars about subjects of particular importance and actuality.
- Direct training to utilities' personnel through a "Study Missions Fund" allowing scholarship and specialist advisories financing.

Members

10 Member Countries: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Paraguay, Peru, Uruguay and Venezuela

3 Associated Members: EDF (France), UNESA (Spain) and TransÉnergy (Canada).

Areas of Activity

At current times, there are five areas, covering all Power Industry segments:

- Generation and Transmission;
- Distribution and Commercialisation; and
- Corporate Area

Within these areas, the following technical matters are covered:

- Planning and environment
- Energy movement and transactions
- Projects and construction works
- Operation and maintenance
- Distribution engineering
- Electric energy commercialisation
- Finance, administration and business
- Legal and regulatory affairs

In addition, there are 13 specific working groups currently in process, established to develop specialized matters, such as: International Interconnections; Operation, Reliability and Quality of Regional Transmission; Hydrometeorology Information System; Quality of Distribution; Benchmarking; Regulation; Information; etc.

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11.3.1.3 ARPEL - Regional Organisation of Oil and Natural Gas Companies in Latin America and the Caribbean

Establishment and Functions

ARPEL is the energy union, where all Member Companies join efforts to further the industry's growth and integration and enhance its reputation in the Region. It is the leading association in the region, with over thirty-five years of experience, making them the heart of the energy sector.

ARPEL is formed by more than twenty-five oil and natural gas companies, which represent over 90% of the region's upstream and downstream sectors. This has placed us in an exceptional position to leverage the industry's efforts and generate knowledge through cooperation and interaction.

ARPEL is an interactive Forum for the exchange of ideas, experiences and knowledge; a Forum designed for a timely identification of issues that may influence the industry's development. We are continously analysing the most relevant issues concerning energy integration, the environment, health, safety, regulation frameworks, social responsibility and the problems affecting the sector, as well as drafting effective proposals for the region.

Interaction and Cooperation are two key features that make us the industry's main point of reference. For this we have the most complete, up-to-date and reliable informative platform available.

ARPEL was created in 1965 as an Association of State Oil Companies to foster cooperation and assistance among its Members. National state oil companies managed the oil industry during those days and up to the beginning of the nineties, being technical and commercial integration and industry's recognition the main objectives of ARPEL activities.

The new scenarios that came up during the nineties after the lost decade of the eighties, with an accelerated trend to globalisation, markets opening and deregulation, brought the need to improve efficiency and obtain funds to finance investments allowing the participation of the private sector.

These important changes led ARPEL to adapt to the new business environment allowing all those companies developing activities in the oil and gas industry in Latin America and the Caribbean to become Members of the Association. Regional integration, a proactive participation in the development process of laws and regulations, the development of cooperation programs with international organizations, and the care of the industry's public image become important objectives for the Organization.

According to this ARPEL has become at present a flexible organization, where all the oil and gas companies discuss the main regional issues of the industry and interact for the interchange of knowledge. The diversity of its membership gives the association a very strong potential to take advantage of the synergies of its Members.

Philosophy

Social responsibility, knowledge and cooperation are values promoted by ARPEL, enhancing the business community's commitment in Latin America, in the belief that we cannot achieve growth and prosperity if we don't contribute to the improvement of society and the protection of our planet's natural resources as a basis for sustainable development.

The Knowledge Management project that the Association is currently implementing -and which is based on these values- aims to further the exchange of information and experiences in specific areas of common interest to its Members. Thus, cooperation contributes to enhance the industry's reputation and minimizes the risks that are associated with the industry.

11.3.1.4 CAF - The Andean Development Corporation

The Andean Development Corporation (CAF) is a multilateral financial institution that promotes the sustainable development of its shareholder countries and regional integration. Serving both public and private sectors, the CAF offers a wide range of financial services to a broad client base composed of the governments of shareholder countries, public and private companies and financial institutions. Its policies incorporate social and environmental variables, and all its operations are governed by criteria of eco-efficiency and sustainability. The CAF has maintained a permanent presence in its shareholder countries, which has strengthened its regional leadership in terms of effective mobilization of resources. The Corporation is currently the leading source of multilateral financing for the countries of the Andean Community, contributing 55% of total funds approved by multilateral agencies from 1997 to 2002.

CAF has a current membership of sixteen countries in Latin America and the Caribbean. Its principal shareholders are the five countries of the Andean Community: Bolivia, Colombia, Ecuador, Peru and Venezuela, which hold Series "A" and "B" shares. The Corporation also has 11 extra-regional partners: Argentina, Brazil, Chile, Costa Rica, Jamaica, Mexico, Panama, Paraguay, Spain, Trinidad & Tobago and Uruguay, which hold Series "C" shares, and 18 private banks from the Andean region which also hold Series "B" shares.

CAF’s headquarters are in Caracas, Venezuela. Representative Offices are located in La Paz, Brasilia, Bogota, Quito, and Lima.

<u>Mission</u>

To promote sustainable development and regional integration by efficiently attracting capital resources to provide a wide range of financial services, with high value added, to the public and private sectors of our shareholders countries.

It is a competitive, client-oriented financial institution responsive to social needs and supported by a highly specialized staff.

<u>Strategic Programmes</u>

The CAF has created or participates actively in various strategic programs, complementary to its business mission, through which it provides financial and non-financial services.

The programs are regional in scope and range from strengthening integration and competitiveness, provision of physical infrastructure, to the development of more equitable, aware, human and participative societies.

- PAC – Andean Competitiveness Program
- Preandino - Andean Regional Program for Risk Prevention and Mitigation
- Biodiversity Program
- Cultural Development Program
- Cóndor Project

- Governance Strengthening Program
- IIRSA -Initiative for Integration of South American Regional Infrastructure
- Kemmerer Program for Development and Integration of Financial Markets
- PLAC – Latin American Carbon Program
- Strategic Support Program for SMEs and Microfinance Institutions

11.3.1.5 IDB - Inter-American Development Bank

A long-standing initiative of the Latin American countries, the Inter-American Development Bank was established in 1959 as a development institution with novel mandates and tools. Its lending and technical cooperation programs for economic and social development projects went far beyond the mere financing of economic projects that was customary at the time.

The IDB's programs and tools proved so effective that soon the IDB became the model on which all other regional and sub-regional multilateral development banks were created. Today, the IDB is the oldest and largest regional development bank. It is the main source of multilateral financing for economic, social and institutional development projects as well as trade and regional integration programs in Latin America and the Caribbean.

The IDB is owned by its 46 member countries. Governance of the Bank is vested in the Board of Governors, which tops the organizational structure of the Bank, and the Board of Executive Directors.

Mission

In its Charter, the founders of the Inter-American Development Bank defined its mission to be to "contribute to the acceleration of the process of economic and social development of the regional developing member countries, individually and collectively."
Though its statement of purpose was written almost half a century ago, the IDB continues to work toward that primary objective, adjusting the focus of its activities and operations to meet the shifting development needs of its member countries in the Latin American and Caribbean region.

Goals and Priorities

The Bank's two main goals are to promote poverty reduction and social equity as well as environmentally sustainable growth. To attain these goals, the Bank focuses its work on four priority areas:

- Fostering competitiveness through support for policies and programs that increase a country's potential for development in an open global economy.
- Modernizing the state by strengthening the efficiency and transparency of public institutions.
- Investing in social programs that expand opportunities for the poor.
- Promoting regional economic integration by forging links among countries to develop larger markets for their goods and services.

Functions

Since its founding in 1959, the Bank has become a major catalyst in mobilizing resources for the region. The IDB provides loans and technical assistance to 26 countries in Latin America and the Caribbean using capital provided by its member countries, as well as resources obtained through bond issues in international capital markets.

Its principal functions are to:

- use funds raised in financial markets, its own capital and other available resources to finance the development of its borrowing member countries;
- supplement private investment when private capital is not available on reasonable terms and conditions; and
- provide technical assistance for the preparation, financing and implementation of development projects.

Members

The IDB was founded in 1959 as a partnership between 19 Latin American countries and the United States. The original member countries were Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Mexico, Nicaragua, Panama, Paraguay, Peru, Uruguay, Venezuela and the United States.

Over the next several decades, the Bank expanded its membership, initially through the Western Hemisphere. Trinidad and Tobago became a member in 1967, to be soon joined by Barbados (1969), Jamaica (1969), Canada (1972), Guyana (1976), The Bahamas (1977) and Suriname (1980). The 18 non-regional or non-Western Hemisphere member countries, consisting of 16 European states plus Israel and Japan, joined between 1976 and 1986. Belize became a member in 1992 and Croatia and Slovenia joined as successor states of Yugoslavia in 1993. The remaining successor states of Yugoslavia decided not to succeed to Bank membership, with the exception of Serbia-Montenegro, which still has the option for admission as a member of the IDB.

Cuba signed but did not ratify the Articles of Agreement, the institution’s charter, so it has not become a member.

Today, the IDB is owned by 46 member states, of which 26 are borrowing members in Latin America and the Caribbean. Each member country's voting power is based on its subscription to the institution's Ordinary Capital (OC) resources.

To become a regional member, a country needs prior membership to the Organization of the American States. To become a non-regional member, a country needs to be a member of the International Monetary Fund. A second basic requirement in both cases is the subscription of shares of the Ordinary Capital and contribution to the Fund for Special Operations.

11.3.2 Argentina

Argentina is one of the largest countries of Latin America in energy production and consumption. It exports energy to both Brazil and Chile, primarily.

The Ministry of Energy defines sectoral policies, establishes rulings for economic dispatch, and regulates the operations of the Wholesale Power Market (WPM), is part of the Ministry of Federal Planning, Public Investment and Utilities.

11.3.2.1 Power sector

Law N° 24,065 of December 1991 defines the regulatory framework of the power sector with the support of the following institutions having the duties described below.

The Ente Regulador de Electricidad – ENRE (Electric Regulator Agency), which supervises compliance with the Law and controls the fulfillment of concession contracts, establishes the bases for calculating regulated tariffs and monitors their enforcement.

The Compañía Administradora del Mercado Mayorista Eléctrico (CAMMESA) (Electric Whole Sale Administrator Company) controls the technical and economic dispatch of the Argentinean System of Interconnection. Economic dispatch arises from the ordering as per the growing variable declared costs for the units supplied, until demand is covered. The market price is determined hourly, based on the marginal cost of the optimal dispatch. Power payments are also considered an economic signal for generating companies to supply the requirements in times of drought.

There is a vertical separation of activities in generation, transportation and distribution:

- Generating companies, which are subject to free competition with no regulated prices (selling at marginal cost on the spot market), may sign freely negotiated supply contracts with distribution companies and large wholesale or retail users (GUMA or GUME, respectively).
- Transportation companies are transmission system operators, with regulated prices and qualities, but have no obligation to expand the system. A fund has been created for financing transmission improvement and expansion works. System users – generating companies and consumers – should pay a fixed charge based on transportation capacity for each line they use, defined using a market bar in proportion to flow rate, with the so-called “area of influence” method.
- Distribution companies are responsible for operating the network in the area of concession, creating a natural monopoly, and relate directly to regulated customers. Power distribution companies compete for concession contracts and must ensure free access to networks. The ENRE establishes the Distribution Value Added for five-year periods, based on model efficient distribution companies with similar regional and service characteristics. Large consumers may participate directly on the wholesale market, paying a transportation fee to the distribution companies. Concessions are for 95 years, but there are administrative intervals of 10 years, during which the licensee may choose to abandon the contract. Provincial authorities control concession contracts and terms.

Customers are the final users and large users. Large users contract freely for consuming electric power supply, freely negotiating supply prices. There are currently two categories: GUMA and GUME.

There is a Wholesale Power Market (WPM) where energy, power and related services are transacted, which is made up of:

- A Term Market: with prices freely negotiated among sellers and buyers.
- Spot (occasional) Market: with prices sanctioned on an hourly basis.

Stabilization Fund

During each quarter, the distribution companies of the WPM pay a seasonal price that is calculated in the respective planning process and approved by the Ministry of Energy based on probabilistic estimates of spot market prices.

The degree of competition achieved by the power sector before the macroeconomic crisis was highly satisfactory, and generation companies were investing in new plants. However, the concentration of property in the distribution activity reduced competition in comparison with what is set forth in the legal framework.[16]

Managing Macroeconomic Problems

For a sector that had achieved an operational market with very favourable results, investments that had raised supply above demand, and better indices than those seen in the period prior to the reforms, the crisis that struck the country's macro-economy in early 2002 dealt a heavy blow and represented a dire test for an institutional structure that is showing it has achieved a level of maturity that has enabled it to address these adverse situations as we shall see below.

The fall of the economy meant devaluation from convertibility (1 to 1 parity between the US Dollar and the Argentinean Peso) to an exchange rate of 4 pesos per dollar at the beginning of the difficulties and falling into default, posed at least two immediate problems for the power market. The first was to define the currency for transactions, as the generating companies demanded that it be the dollar, while the distribution companies demanded that bonds issued by the provinces be used, as they were obliged to receive them by decision of the provincial authorities. The authorities of the sector decided to keep it in pesos, which meant sharing the sacrifice, because the distribution companies had to negotiate the bonds they received at a discount, while for the generating companies it meant financial problems.

The second immediate problem to be solved was how to finance the operations of the sector, since the first months of 2002 had 50% of all traded energy unpaid.

Only by the end of 2002 and beginning of 2003 were payments regularized, although the real value was not covered due to devaluation.

Fortunately, during 2000 and 2001, hydrological surpluses over normal averages meant that seasonal prices[17] were above the spot market, and the differences accrued to the so-called

[16] Petrecolla, Diego and Ruzzier, Christian. "*Competition Defense Problems in Argentina Infrastructure Sectors*". *Themes, Enterprise University of Argentina*, UADE, *Group Editorial SRL*, 2003.

[17] Seasonal prices, defined quarterly for sales to distributors based on a probabilistic estimate.

Stabilization Fund. This fund, whose intention was solely to balance seasonal differences, made it possible to keep up payments to generation companies until June 2003, thus offsetting the deficits caused by frozen seasonal prices.

As of June 2003, a debt has been accruing to generating companies who accepted receiving payment of only operational costs, with the difference complemented by papers which are undated IOUs. The government, in turn, contributed US$ 1,000 million (by August 2004) to cover the cash amounts committed, that is, the costs.

Supply has sufficient reserve to cover the demand foreseen up to 2006 based on solving the natural gas supply issues, with the strategy laid out by the Ministry of Energy, as we shall see below.

In order to set longer periods for adjusting the lower-income sectors, residential and generally regulated demands were segmented into three categories: less than 10 kW, from 10 to 300 kW and more than 300 kW. The first tariff increases were carried out in each segment, by 40%, 80% and 120%, respectively.

To September 2004, work had been done on a proposal to begin progressive increases and governmental contributions, which would make it possible to gradually recover the purchase value of payments to companies, with the condition that part of the new revenue would go to finance a new combined cycle plant in Rosario, in order to meet the demand for 2007.

Furthermore, the default proposed by the government helped by giving the companies of the sector a break in fulfilling their financial obligations on the low income they were receiving, as it enabled them to renegotiate their loans.

Note that transmission worked as planned in the regulations, and no more works were built as they were not needed. The transportation companies are only the operators of the transmission system and do not have any obligation to attend to expansions. A fund was set up to finance these works.

In summary, as long as the adjustment stage lasts in the power sector, two regulations coexist: one is that of the free market, which is suspended; and the other is transitory, for as long as it takes to return to the former situation.

11.3.2.2 Gas sector

In December 1992, Law No. 24,076 was passed establishing the normative framework for natural gas and creating the institutions of the sector. The chain making up the natural gas sector in Argentina is segmented vertical and horizontally, which does not mean the disappearance of natural monopolies for the transportation and distribution of natural gas.

The Ministry of Energy – defines sectoral policies and authorizes gas exports. There is freedom to import natural gas.

The ***Ente Regulator del Gas*** **(ENARGAS)** (Gas Regulator Agency) – the autarchic regulator of the gas industry, the arbiter of disputes among players, dictates safety regulations and technical procedures, prevents monopolistic, anti-competition or discriminatory behavior, establishes the bases for calculating and approving tariffs for transportation companies and distribution companies.

Production Companies – hold a hydrocarbons exploitation concession and extract natural gas whose production they can dispose of under a free competition regime at unregulated prices (on the spot market), may sign supply contracts freely with marketing companies, distribution companies and major users.

Marketing Companies – are the players who purchase and sell natural gas on behalf of third parties.

Transportation Companies (*Transportadora Gas del Norte* and *Transportadora Gas del Sur*) – are enabled to provide transportation service and can neither buy nor sell natural gas, from the point of entry to the transportation system to the point of delivery to the loaders (distribution companies and consumers who contract directly with production companies and warehouses). They function as natural monopolies in their area of operation and are subject to national concessions, with regulated tariffs and quality. Their expense control is done through accounting systems that have been approved by ENARGAS.

Distribution Companies (nine distribution companies, one per zone) – provide gas supply service to final users final users who do not contract supply independently, negotiating directly with the producer or marketer. They constitute a natural monopoly, with prices regulated by ENARGAS. Their accounting systems should be approved by ENARGAS in order to control all expenses.

Consumers – are small and large final users. Large users may contract their natural gas supply independently for their own consumption, freely negotiating the transaction conditions, without prejudice to the rights granted to distribution companies for their habilitation.

Managing Macroeconomic Problems

In 2004, the country had difficulties completing the supply required by demand increases, taking into account that 49% of Argentina's energy balance is covered with natural gas, and it was necessary to restrict exports to Chile, rehabilitate an old gas pipeline from Bolivia in northern Argentina, and complete electric generation by operating costly fuel oil power plants.

Work is being done on a gas pipeline that runs parallel to the one operating from Bolivia, which will help increase supply towards the centre of the country. Additionally, another one is planned to run through the northeast of Argentina, supplying a zone that lacks gas supply, closing a loop with Brazil, Argentina and Bolivia, and integrating the new Santos fields in Brazil with the Bolivian reservoirs.

Gas prices, which are defined by virtue of electric prices, were also frozen at a third of the price before the crisis, from $1.2 to 0.40 per million BTU.

As with the power sector, consumption was segmented in order to accelerate price increases to sectors with greater capacity to pay, only that in this case the adjustment in the industrial sector is better represented than in the case of electricity, with a 70% share, and the adjustment in the highest consumption sectors is expected to be completed in 2005.

Conclusion

The country's economic crisis affected the operation of the energy sector by reducing prices to 33% of their previous values. This meant that the institutionality of the sector and its organizations were submitted to a dire test, having suffered from political pressures on the one hand and from agents participating in the market on the other.

The observed facts are that private companies, doubtless with a long-term vision, supported the efforts of the authorities and the agencies, and remain in expectation that in time the adjustments will enable returning to the former situation.

11.3.3 Brazil

The country with the largest territorial extension in Latin America is seeing a major growth in its oil, natural gas and electricity consumption. Its authorities, with the support of Petrobras, are exerting great efforts to self-supply its demand, such as in the experience with using gasohol as an example for the region and the world.

Following a reform process to create a free market model, which begun in 1996, the country suffered a supply deficit that forced it to rethink the model it was in the process of implementing.

The changes were produced due to reasons that were endogenous to the country's power sector, upon examination of the purposes for the reforms and their fulfilment, because even accepting that the plan was not completed to implement the former model, the problems of lack of investment in new generation plants demanded rapid solutions. An attempt was made to correct the deficiencies seen in the former model in order to promote development in the sector.

The purposes for earlier reforms were to ensure energy supply and lower consumer prices, removing the State from utility administration.

State withdrawal from company ownership (privatization) began with the distribution companies. Today most are private, owned by companies with foreign and domestic capital, which manage approximately 70% of the market. Publicly-owned distribution companies have state and mixed stock and maintain vertical integration in generation and distribution. The smallest ones are municipal.

In the case of generating companies, the same does not occur, as the privatization schedule was not fulfilled and only about 15% of all generation belongs to the private sector. Additionally, some state-owned distribution companies did not comply with the vertical separation of generation, which still accounts for some of their assets.

Note also that the reform process began in 1996 and became effective in 1998, after which it took time to organize and mature the Agencia Nacional de Energía Elétrica– ANEEL (National Agency of Electric Power). However, some members of its technical staff still have temporary contracts or are on loan from other institutions.

With the reforms in effect, national-scale blackouts occurred in March 1999 and in January 2002, the latter of which put in evidence the limitations of the transmission system. Towards the end of 2001 and beginning of 2002, it was necessary to ration energy in the country by up to 20% of the demand.

On a positive note, the rationing caused a change in energy consumption habits, the incorporation of efficient equipment, and substitution of electric power consumption with other sources, which meant that demand remained at low levels after the rationing period and began recovering only in 2004. Note also that the activities of PROCEL (Electric Energy Savings Program) had prepared the population beforehand to begin thinking in terms of energy efficiency, only that the crisis accelerated the process.

As a consequence of rationing, a growth in supply from thermal gas plants, in which *Petrobras* is a partner, was also encouraged, and there was a raise in tariffs.

Transmission was a good business with positive results, both for the companies and for the system, as the owners' revenues were ensured, but expansion was achieved through a planned process. The (National System Operator) ONS, jointly with the (Coordinator Committee for Electric Power System Expansion Planning) CCPE, made a proposal to ANEEL for all needed expansion and strengthening, and ANEEL tendered out the appropriate installations (lines, sub-stations and others)[18]. The transmission system works like a condominium, where revenue is shared among all owners, which has enabled investments in transmission to develop as planned.

The Operation Coordination for Interconnected Operation - GCOI, made up of all companies on the system, operated from 1973 to 1998, making it possible to harmonize technical and business criteria among all.

In 1998, the ONS began its function of centralizing operations, with technical vision but without the capacity to harmonize business criteria. Although initially the companies resisted abiding by provisions dictated by the ONS, to date the planned functioning has been achieved.

In summary, the goals set by the former model were not met, particularly in the case of rationing, because the guaranteed supply was not achieved due to a lack of market response in increasing supply. Furthermore, tariffs did not go down, and the companies continued in financial crisis.

Since the transfer of state-owned companies to private investors did not end up as planned, and the vertical separation of generation and distribution was not entirely achieved either, the former model was not completed as planned.

Additionally, in the former model, public contests were held for the concessions, and the company bidding the highest payment for the concession was awarded, which payment was then recovered through tariffs; neither were energy sales contracts required. That is, projects had no commitments for purchasing the energy to be produced, and distribution companies had no obligation to contract all the energy that the demand in their concession area required.

New Model in the Power Sector

The new model attempts to include solutions to the problems detected, incorporating two energy negotiation environments. One is free negotiation among generating companies, marketing companies and major customers, while the second is attended by all distribution companies to negotiate as a group with all generating companies until contracting 100% of their demand and proportionally distributing each generator's share in contracts with each of the distribution companies. In order to keep their contractual commitments, the distribution companies will have a guaranteed "pass through." At September 2004, the rules of operation are under public consultation.

The new model was adopted after discussions held by the Ministry of Energy and Mines with all stakeholders. Plans for expanding and operating transmission that worked well were not altered. Likewise, the rules for the ONS were not changed in terms of functioning, but rather in administrative terms. The market agents' assembly elects the members of the Administrative Council, which only has a say in managerial matters. The Board of Directors is in charge of technical issues, and is made up of three members elected by the Ministry of Energy and Mines, and two elected by the market agents. Board members hold office for 4 years but may be terminated during the first 4 months of their duties.

[18] Electricity History Center of Brazil, "History of National Interconnected Operation," ONS, Rio de Janeiro, 2003.

Separation of activities is insisted on in the case of distribution companies that still own generation components.

The authorities clarify that all contracts in effect will be respected up to the agreed dates, so that the new model will be incorporated gradually.

The largest change is seen in the auctions for new generation developments to cover the projected demand 3 to 5 years in advance. An amount of new supply will be auctioned, which interested parties may bid on in whole or in part, with projects that already have the preliminary economic feasibility and environmental permits, and those offering the best conditions at the lowest prices will be awarded.

Auctions for existing generation will be promoted one year in advance of the demand, and the Ministry of Energy and Mines will define the maximum purchase price, which as of 2009 may not surpass the maximum purchase price of auctions for new plants coinciding with the supply year. ANEEL will not be in charge of these auctions, but rather the directives established by the Ministry of Energy and Mines will be followed.

The auction amounts will be defined by the Electric Research Company - EPE, which will carry out country-level demand integration on the basis of demand forecasts for each of the distribution companies. The distribution companies will formally present their own demand projections in their concession area for the next 5 years (Decree 5,163 of July 2004) and will be co-responsible for estimating the magnitude of the bid to offer.

Additionally, the EPE will carry out feasibility studies for new generation projects and will supply them with the preliminary environmental license, in order to place them at the disposal of those interested in taking them in the auctions.

Additional auctions will be encouraged to complete the needs of distribution companies up to 1% of the total load contracted by the company, with a supply period of up to two years. Distribution companies may make adjustments in their long-term projections by a maximum of 3%, three years in advance, and with one year adjustments may not exceed 1%. Should distribution companies have a greater demand than forecasted, they must purchase energy on the spot market and may not pass the cost on to their customers.

The Electric Energy Commercialization Chamber - CCEE, (Decree No. 5,177 of August 2004) created as part of the new model to hold energy purchase and sales auctions, register sales and purchase contracts in the regulated environment and record the contract amounts in the freely negotiated environment, replaced the Wholesale Energy that was operating before.

A Sectoral Monitoring Committee was also created, which must check compliance with demand forecasts and development consistent with bids.

11.3.4 Chile

Chile has limited resources of its own and must support its supply with imports.

The **Ministry of Economy and Energy** is the authority that sanctions the sectoral regulations, sets regulated prices based on studies by the CNE, grants public utility concessions, reporting to the SEC, and solves differences between the members of the Economic Load Dispatch Center - CDEC).

The ***Comisión Nacional de Energía*** – CNE (National Energy Commission) is the Regulator of the Sector, prepares plans and policies for the energy sector, develops energy demand and supply forecasts, and technically reviews price structures and levels.

The ***Superintendencia de Electricidad y Combustibles*** (SEC) (Electricity and Fuels Superintendence) audits and supervises compliance with legal and regulatory provisions, technical standards for generation, production, storage, transportation, and distribution of liquid fuels, gas and electricity. It audits compliance with the technical standards of the sector and checks the quality of services provided to users. The natural gas business, transportation, distribution and marketing are subject to regulation.

11.3.4.1 Power sector

The current legal framework has been in effect since the 1982 and defines the duties and activities of the institutions as detailed below. In March 2004, second generation reforms were approved that attempt to improve certain aspects, as noted in the text, deriving from experience with market operations.

The ***Centro de Despacho Económico de Carga*** **-** CDEC (Economic Load Dispatch Center) is in charge of the joint operation of generator plants and lines of the electric system, for the purpose of achieving the minimum cost possible in power supply, with an established security. It is made up of the generation and transmission companies that have an installed capacity and length of transmission lines above prefixed amounts. The Board of Directors is made up of one representative from each company.

Although **Free Customers** were those above 2 MW of installed power and represented 55% of the market, recent reforms reduced the limit to 500 kW with the idea of expanding the space for free negotiation.

The **Regulated Market** is made up of the distribution companies and customers with an installed power below the limit for Free Customers. The so-called Node Prices are the maximum transactions in each bar of the system, determined by the National Energy Commission every six months, which should not have a difference greater than 5% of the average prices for the last four months of the free market (the reforms of March 2004 reduced the limit from 10% to 5%).

There is the **Competition Tribunal** that was established on the basis of Decree Law 211 of 1973, amended by Law No. 19,911 of November 2003 that came into effect in February 2004 and began to operate in July 2004.

Besides what has already been pointed out, the amendments of March 2004 attended to certain topics, which included:

- They specified the procedures for determining transmission tolls, in order to enable the development and remuneration of 100% of the transmission system to the extent that it is efficient.
- They specified the toll norms, particularly for sub-transmission, to enable bidders other than distribution companies access to Free Customers located in the concession areas of the latter.
- They introduced the market of supplementary services, establishing the transaction and valuation of technical resources and making it possible to improve the quality and security of services.

- They establish a mechanism for solving disputes within the power sector, both between companies and the authority, and among companies, by establishing a highly specialized panel of experts made up of seven professionals, two of which will be lawyers and the other five engineers and/or economists with much expertise in the sector.
- Conditions were improved for developing small, non-conventional power plants, mostly using renewable energy, by opening the electric markets to this type of plants, establishing the right to dispatch energy through the distribution systems, and exemption from payment of tolls for the use of the trunk transmission system.

Chile has 4 electric systems:

- the *Sistema Interconectado del Norte Grande* – SING (Large North Interconnected System) with 33.9% of all installed power, the *Sistema Interconectado Central* – SIC (Central Interconnected System) with 65.2% of all installed power, and
- the systems of *Aysén* and *Magallanes*, with 0.3% and 0.6% of all installed power.

In the SING, in terms of generation company ownership based on installed power, four investment groups are participating: ENDESA with 22% and two companies, AES with 27% and two companies, Edelnor with 21% and one company, and Electroandina with 30% and one company.

In the SIC, the active business groups with a share in installed power are: ENDESA with 51% and four companies, Chilectra Generation – AES with 22% and 3 companies, and Colbun with 17%.Gas sector

The sectoral reforms set up since 1978 established a normative framework that regulated the functions and activities of the following actors.

Production Companies, especially the ***Empresa Nacional del Petróleo*** – ENAP (National Petroleum Company), which operate individually or in partnership with third parties, extract natural gas from reservoirs located in Chilean territory and control 80% of all fuel demand, while the other 20% is covered with independent imports.

There is freedom to **import** natural gas, complying with certain administrative and legal requirements.

Transportation Companies provide the natural gas transportation service from the point of entry to the transportation system to the point of delivery to distribution companies. For consumers contracting directly with production companies, and warehouses, the ENAP and private companies intervene. These are natural monopolies through non-exclusive concessions, and there may be several for the same point of origin and destination of transportation, with regulated tariffs.

Marketing Companies are those who purchase and sell natural gas on behalf of third parties.

Distribution Companies provide the service of gas supply to final users that do not contract their supply independently. They constitute a natural monopoly based on non-exclusive concessions, and there may be several for the same distribution area or points of origin and destination of transportation. Distribution companies purchase natural gas directly from production companies or marketing companies.

Consumers are small and large final users. Large users may contract their supply of natural gas independently for self-consumption, negotiating the transaction conditions freely, without prejudice to the rights granted to distribution companies.

The recent problems of supply restrictions from Argentina created a secondary market with the quotas. However, in the power sector, the generating companies optimized the coordinated use with production from the other plants of the system.

11.3.5 Colombia

Colombia is a producer of oil and coal, which go to internal supply and for export.

The **Ministry of Mines and Energy** is the sectoral authority, establishes the policies, regulates, plans and coordinates all activities relating to the electricity utility.

The ***Unidad de Planificación Minero Energética*** – UPME (Mines and Energy Planning Unit) is an administrative unit under the Ministry of Mines and Energy, has administrative and budgetary autonomy, is responsible for integral indicative planning for the sector, determining the energy requirements of the population, and defining long, medium and short-term plans for the sector.

The ***Comisión de Regulación de Energía y Gas*** **–** CREG (Energy and Gas Regulatory Commission) is an administrative unit under the Ministry of Mines and Energy. It regulates the supply of public power and gas utilities. In the case of natural gas, it regulates the activities of transportation, distribution and marketing. It must also promote free competition and avoid the abuse of dominant position in the supply of public power and natural gas services. The CREG has promoted a framework of supervised freedom based on norms and tariff formulas for agents in the natural gas supply chain.

The ***Superintendencia de Servicios Públicos Domiciliarios*** **–** SSPD (Domestic Public Services Superintendence) is under the Ministry of Economic Development. Its duties include inspection, oversight and control of all companies providing public household services, including natural gas, and supervision of the CREG.

11.3.5.1 Power sector

The 1994 Law restructured the Colombian power sector, placing limits on vertical integration, incorporating the marketing activity into those of generation, transmission and distribution, creating the wholesale electricity market, including private participation and an institutional layout that is described below.

The ***Empresa de Interconexión Eléctrica S.A.*** – ISA (Electric Interconnection Company), with a majority of state capital (72%), is responsible for most of power transmission in the country. Furthermore, it is in charge of managing Wholesale Power Market and operating the national transmission system.

There are currently 40 **Generating Companies** in which the private sector has 44% of all shares.

There are 33 **Distribution Companies** with an approximate share of 50% of all private capital stock.

The **Electricity Negociation** may be carried out by generating companies, distribution companies and companies dedicated exclusively to this activity. There are approximately 66 marketing companies.

The **Unregulated Users** are empowered to negotiate their supply directly and are those with a demand greater than 100 kW or 55 MWh per month. They represent some 40% of the national demand.

An international assessment of power market operation established that the results are satisfactory, once overcoming the problems caused by the large state presence in the distribution companies, especially the lack of payment guarantees for energy delivered by the generation companies.

11.3.5.2 Gas sector

The State manages the country's hydrocarbons through the ***Empresa Colombiana del Petróleo*** – ECOPETROL (Petroleum Colombian Company), which carries out oil production and transportation directly or in association with private companies. The owner of most of the oil products refining and storage business, over the past years it has transferred its gas pipeline transportation system facilities to the gas company and has sold its share in natural gas distribution companies. ECOPETROL tends to work solely on upstream activities.

The ***Empresa Colombiana de Gas*** **–** ECOGAS (Gas Colombian Company) is in charge of projecting, building, operating, managing and commercially exploiting its gas pipelines. Initially, it had the gas pipelines transferred from ECOPETROL and, later on, the new gas pipelines that have entered into operation.

11.3.6 Cuba

The **Ministry of Economy and Planning** defines energy policies on a national level.

Cuba adopted the sole purchaser model in 2000, keeping the vertically integrated state company called the ***Unión Eléctrica Nacional*** – UNE (National Electrical Utility)**,** which is the national company in charge of power generation, transmission, distribution, and marketing throughout the country. The UNE includes: (i) the National Load Dispatch, which is responsible for operating the generation plants and transmission lines; and (ii) six departments under which are a series of companies (projects, construction, etc.), including 14 distribution companies. It operates an independent producer in a mixed economy company that is expanding its share to a new plant that is under construction.

The UNE reports to the **Ministry of Basic Industries (MINBAS)**, which sets the overall policy guidelines and approves the tariff schedule and levels proposed by the UNE. Independent power production companies participate who, through concessions and licenses, sell the generated energy to the UNE and whose participation is subject to centralized minimum cost planning. There is a sole tariff for the entire national territory, environmental protection is attended to, and there are service quality standards that promote energy savings and efficiency.

There is one independent power producer operating one power plant with a shared ownership with the government and they have a new power plant under construction.

11.3.7 Mexico

This is the country with the largest oil exports outside of the group that belongs to the OPEC. Most of its exports go to the United States due to its vicinity to that country.

The **Ministry of Energy** is the State secretariat with the duty of defining and directing national energy policy. It also coordinates the sector, where public companies are decisive, the largest companies in the country being *Petróleos Mexicanos* (Pemex) (Mexican Petroleum Company) and its subsidiary bodies, the *Comisión Federal de Electricidad* (CFE) (National Electric Utility) and *Luz* *y Fuerza del Centro* (LFC) (Capital City Utility). We should mention that Pemex has been named one of the 10 major companies in the world due to its assets and revenues.

The ***Comisión Reguladora de Energía*** (CRE) (Regulatory Commssion) is a deconcentrated body of the Ministry of Energy, with technical and operational autonomy, whose decisions are made jointly among the five commissioners it consists of, in charge of regulating natural gas and electric power. Its responsibilities include granting permits, authorizing prices and tariffs, approving terms and conditions for service provision, issuing general administrative provisions (directives), solving disputes, requesting information, and applying sanctions. Tariffs are approved by the Treasury Department.

11.3.7.1 Power sector

Reforms began with the Public Power Utility Law of 1992, which contemplates special treatment for independent production companies, cogeneration, self-supply, small producers, and imports and exports. Also, the *Comisión Reguladora de Energía* was established. Since the reform, the institutional organization is as explained below.

The state companies "***Comisión Federal de Electricidad***" and "***Luz y Fuerza del Centro***" vertically integrate the activities of the sector.

11.3.7.2 Gas sector

Petróleos Mexicanos **(PEMEX)** is responsible for the oil and gas sector, which includes natural gas. Exploration and highly specialized technical services are done by the *Compañía Mexicana de Exploraciones S.A*. (Mexican Exploration Company).

Oil and gas marketing, done internationally by *PMI Comercio Internacional, S.A. de C.V.*, is a decisive factor for the generation of foreign currencies and tax contributions for the federal government.

11.3.8 Peru

Peru has a large potential to participate on natural gas markets with its Camisea reserves that began to be exploited in 2004 with the arrival of the gas pipeline from that field to Lima.

The **Ministry of Energy and Mines** (MEM), through the Electricity General Direction as a technical regulatory body, is in charge of proposing and/or issuing standards for the power generation, transmission, distribution, and marketing activities, signing power concession contracts, granting power generation approvals, sectoral planning, and also promoting the development of the sub-sector.

11.3.8.1 Power sector

Since the reforms of 1990, this sector has a normative framework that is oriented to liberalizing the market and free competition, with the activities of the sub-sector separated, on which basis assets were transferred to the private sector and investments were captured. The expansion of installed capacity by private initiatives has received investments for an estimated total of 4,600 million dollars from 1993 to 2003 (2,700 of which were from the private sector). Of the total investments, generation received 2,400, transmission received 612 and distribution received 1,628.

This normative framework covers the following participants in the power sub-sector.

The ***Organismo Supervisor de Inversión en Energía*** – OSINERG (Investment Supervision Body) is in the scope of the MEM to supervise energy sub-sector activities to ensure that they comply with the legal provisions and technical standards of the power and hydrocarbons sub-sectors, and fulfill the provisions relating to environmental protection and conservation. The resources for OSINERG come from contributions made by the companies of the sector, and its duties are normative, regulatory, supervisory, auditing, and penalizing. It also fixes tariffs for public utilities, transportation and distribution.

The ***Comité de Operación Económica del Sistema*** – COES (System Economic Operation Commitee) is made up of the generation and transmission companies of the interconnected system, with the purpose of minimal cost dispatch and settlement of transactions on the market. The COES Board of Directors consists of 9 members, 8 representatives from the generation companies and 1 from the transmission companies. Also attending with a right to speak but not to vote is a representative of the distribution companies and one of the Major Customers. Taking into account that several generation companies belong to the same group of investors, each group may have a maximum of 2 board members.

Electric Companies are power concessionaires and authorized agencies, which may be generation, transmission and distribution companies.

Free Customers (demand over 1 MW) negotiate directly with their suppliers under a competition regime.

Complementing direct participants is the ***Instituto de Defensa de la Competencia y de la Propiedad Intelectual*** – INDECOPI (Institute for Competition and Customer Defense). In the power field, it oversees compliance with the laws of the market and defends the interests of consumers and companies that may have been adversely affected.

Ownership of the Power Sub-sector

The largest private owners of the sector are:

In generation with the percent share in effective installed power: Endesa with 23.3% (Spain), Duke Energy with 10.4% (USA), and Tractebel with 6.5% (Belgium). The Peruvian state retains 47.4% of all installed power. In transmission: ISA (Colombia), Hydroquebec (Canada) and *Redes de España* (Spain).

In distribution: Endesa and SPG.

11.3.8.2 Gas sector

The Peruvian natural gas sector is organized with a vertical segmentation. The transportation companies and distribution companies must allow third parties free access to their systems' transportation capacity, provided it is not committed to supply contracted demand.

The gas market participants are as detailed below.

The **Ministry of Energy and Mines** (MEM), through the Hidrocarbons General Direction (DGH), is the governing body with normative duties, the concessionary body, and the promotional body. It is in charge of granting licenses and concessions for the exploitation of hydrocarbon activities, both oil and natural gas.

Perúpetro is a private law state company. In its capacity as Contractor, it is in charge of promoting, negotiating, formalizing, and supervising the fulfillment of license contracts or of exploration and exploitation services. It retained these activities from the former corporation, *Petroperú*.

The ***Organismo Supervisor de la Inversión en Energía*** (OSINERG) has the same duties as described under the power sub-sector, because its duties include the two sub-sectors.

Production companies have license contracts or contracts for hydrocarbon exploitation services, that extract natural gas from reservoirs located within the national territory. The Law allows them to freely dispose of gas production, subject to free competition, they may sign freely negotiated supply contracts with marketing companies, distribution companies and large users.

Marketing companies are individuals or corporations that purchase and sell natural gas transportation or distribution capacity, on their own account or on behalf of third parties, being neither concessionaires nor transportation companies.

Transportation companies are enabled for natural gas transportation service from its entry into the transportation system to the point of delivery to loaders (distribution companies, consumers that contract directly with the producer).

Distribution companies are enabled to provide gas supply service to final users that do not contract their supply independently, with prices regulated by OSINERG. The distribution companies carry out natural gas purchasing operations, negotiating directly with production companies or marketing companies.

Consumers are small and large final users. Large users may independently contract their natural gas supply for self-consumption, freely negotiating the conditions of transaction, without prejudice to the rights granted to distribution companies for their habilitation.

11.3.8.3 Market operation experiences

There are a few aspects that arise from market operation experience, which may be summarized as follows:

Since transmission signals do not work entirely well, it has been decided that the indicative plan for the sector, developed by the MEM, should not only be indicative in the case of transmission, but should also be binding, thus making it possible to promote system expansion by virtue of the established requirements.

Tariffs are set on the basis of marginal cost of the 48-month work plan. There is then the issue of discretionality for OSINERG (excess of power) if it is the one to select works to be included in the base plan.

The distribution companies are obliged to contract all the energy they require for their customers and show the supply guarantee by December of the current year under penalty of losing the concession. However, since marginal costs are above the bar prices, the generation companies have rejected that contracting, and the MEM has decided to dictate an emergency decree to free the distribution companies from the requirement established in the Law of Concessions.

CAMISEA Field

Exploitation: Reservoir exploitation requires an initial processing to separate dry gas from the liquids. Therefore, there are two pipelines that run parallel for the initial stretch and then separate, the one that transports liquids with capacity of 33,000 barrels per day that terminates in Pisco on the southern coast, and another for dry gas that continues northwards to Lima. The initial part of this pipeline has larger capacity tubing (1000 million cubic feet per day) in order to limit disturbances to an environmentally sensitive section of virgin forest. (It was built without access roads, transporting materials by river and helicopter). Then the tubing section is reduced to adjust to the country's domestic demand (400 thousand cubic feet per day). Calculated reserves are 8.7 TCF, which represents 60 years of domestic consumption.

Exploitation is under the responsibility of a consortium that includes Pluspetrol, the head of the consortium, Zonatrac (Algeria), SK (Korea) and Hunt (USA).

Transportation: TGT (Techint, Argentina) is in charge of the gas pipeline.

Distribution: the Company *Gas Natural de Lima y Callao* (GNLC) of Tractebel, from Belgium.

PAGORANI Field

With an initial reserve estimate of 3.0 TPC, final exploration has been awarded and is being signed with the same consortium that exploits Camisea, only that now it is headed by Hunt.

Oil

Exploitation: Pluspetrol manages oil exploitation in the Northeast (the largest) while Petrobras, Petrotech and Saped (China) are in the North. Petrobras is offshore. There are currently fewer participants than before privatization.

Refining: Before, it was a monopoly activity in the hands of the state-owned company Petroperú. Now three players participate: Repsol, with the largest refinery and another small one; Petroperú with 4 small refineries; and Maple, located in the Central Forests with supply to a limited territory due to its geographic situation. There is competition between Repsol and Petroperú, which due to production limitations cannot have very different prices.

Wholesale Distribution: Participation has very few restrictions, and 25 are qualified. The demands for a minimum of six months advance distribution are not required for reentering companies. Some manage limited volumes without inventories. An attempt is currently being made to better define the rules for participation as a wholesaler. Before, this was a state monopoly.

Retail Distribution: Since before the reforms there was a free market, and this remains the same.

Lubricants: Before the reforms, the state-owned company Petroperú supplied 50% of the market and Mobil supplied 26%. With the privatization, Mobil purchased that 50% and took control of the market, reducing the level of competition.

Levels of Competition, INDECOPI's Vision

Final consumer prices have shown a downward trend. However, in terms of tariffs there is no real competition because tariffs are fixed by the regulator, who takes into account free market prices as a reference and generally those prices have been higher than the regulated prices.

The Law of Concessions establishes the limits for participation on the market, for vertical integration over 5%, and horizontal over 15%, for stock ownership transactions, after which the companies should notify INDECOPI and the Free Competition Committee reviews the effects that the levels of participation could have on competition in the respective market.

INDECOPI is organized by rooms that attend to the different issues the institution is in charge of. These rooms may be the second instance in the claims that are processed.

The largest participation in the generation segment belongs to the group of plants belonging too the Peruvian state and, in second place, to ENDESA.

The evolution of the Hirschman Index – Herfindhal (IHH)[19] has declined by 25% from 1997 to 2002, reaching values that are relatively high for international levels, but explainable in a market the size of the Peruvian one,[20] a reduction that is similar in percentage to the bar prices.

11.3.8.4 Regulation and tariffs

In Peru, there is twelve years of market experience, but the former Tariff Commission only joined OSINERG since 2001.

As part of that experience, note that the transmission trunk had free access and was regulated, while the branches were not regulated considering that they had to be built for and only for a specific function. However, experience has shown that later developments obliged using those branches for additional purposes, feeding new loads or receiving new generation, and access problems arose. Therefore, since December 1999, branches are also under the general transmission regulations.

Customers of less than 1 MW have tariffs that are regulated by OSINERG, based on established bar prices. Customers of over 1 MW are free, but network use has regulated tolls.

Bar prices are set for 4 years, but the drought supported by hydroelectric plants since eight months ago have pushed prices for Free Customers upwards. Regulated tariffs should normally remain within a band of more or less 10% of the free market price. However, since norms demand that large customers present their contracts to the regulator, for contracts containing aspects other than general negotiations between the generation company and the customer, such as assets transfers and others, prices per kWh are not entirely transparent to the regulator. This caused serious problems for precisely determining the free market price.

Apparently, competition has been sacrificed by the presence of regulated bar prices for distribution companies.

11.3.8.5 Interconnected system economic operation committee, COES

To date, there are 14 generation companies and 5 transmission companies. Apparently there is a lack of mechanisms for planning expansions, and a lack of a defined process for transmission expansion decisions.

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[19] IHH reflects the table of participations in the market.

[20] Ruiz, Gonzalo, “Privatization, Competition Policy, Economic Deregulation and their Impact on Competitiveness: The Case of the Electric Power Market in Peru”. Included as part of the book: Brusick P., Alvarez A.M., Cernat L. and Holmes P., “Competition, Competitiveness and Development: Lessons from Developing Countries”, published by the United Nations Conference on Trade and Development, UNCTAD / DTC / CLP / 2004 / 1 United Nations Publication.

Also, there is the perception that regulated bar prices have remained below free market prices or even below spot market prices and hourly settlements, which has caused claims on behalf of the generation companies.

Furthermore, the possibility of including natural gas from Camisea in the gas pipeline that has entered operation, in existing and new plants, bodes well for a price reduction.

11.3.9 Venezuela

Due to the size of its oil reserves, Venezuela is an important supplier in the world, among the top ten of the planet.

The **Ministry of Energy and Mines** (MEM) is responsible for the direction of the sector and, through the Vice-minister of Energy, formulates sectoral policies, develops plans and audits the activities of the power, oil and gas, and mining sectors. It defines regulatory policies is in charge of transmission and distribution concessions, as well as granting authorizations for generation.

11.3.9.1 Power sector

The Power Sector Law issued in September 1999, establishes the creation of a Wholesale Power Market, based on the principle of free competition in energy production and marketing activities. In December 2001, the Organic Electric Utilities Law was passed, modifying the terms initially established for commencement of operations by the regulatory agency, the ***Comisión Nacional de Energía Eléctrica*** – CNEE (Electric Power National Commission) and the ***Centro Nacional de Gestión del Sistema Eléctrico*** – CNG (Electric System National Administration System), in charge of Wholesale Power Market administration and operation. Market operation has taken a long time, and the terms have had to be modified.

In the power sector, 13 electric companies operate with diverse degrees of vertical integration, eight of which are privately owned. Four of these have AES of the United States as its majority shareholder, one belongs to Enron, another to Venezuelan shareholders, and another to a paper producer and the Public Service Enterprise Group (PSEG Global).

11.3.9.2 Gas sector

The ***Ente Nacional del Gas*** – ENAGAS (National Gas Agency), which is autonomous but reports to the Ministry of Energy and Mines, relates the gas production sector to consumers, seeking the incorporation of private domestic and international capital, and supervising the conditions of equity among private and public players, under defined rules and regulations to promote the development of the gas industry.

Tariff setting for final consumers is under the Ministry of Energy and Mines and the Ministry Production and Commerce, while ENAGAS develops the bases for tariff definition. Retail consumer tariffs are made up of the gas purchase price, the transportation tariff, plus the distribution tariff.

11.4 Annex 4 – Shares of international stakeholders at LAC power generation and distribution companies, 2004

Endesa (Spain)

Group	Country	Company	Sector	%	Indirect %	IndirectVia
Endesa	Argentina	CBA	Electricity generation		11.9	Enersis
Endesa	Argentina	Costanera	Electricity generation		23.4	Enersis
Endesa	Argentina	Distrilec	Electricity		13.9	Enersis
Endesa	Argentina	Dock Sud	Electricity generation			
Endesa	Argentina	EASA	Energy			
Endesa	Argentina	Edenor	Electricity			EASA
Endesa	Argentina	Edesur	Electricity distribution		9.6	Enersis
Endesa	Argentina	El Chocon	Electricity generation			Enersis
Endesa	Argentina	Yacylec	Electricity transmission	22.2		
Endesa	Bolivia	Elfec	Energy		34.9	Enersis
Endesa	Brazil	Cachoeira Dourada	Electricity generation		60.6	Enersis
Endesa	Brazil	CERJ	Electricity distribution		25.5	Enersis
Endesa	Brazil	Cien	Electricity transmission			
Endesa	Brazil	COELCE	Electricity distribution	33.06		
Endesa	Brazil	Fortaleza	Electricity generation		60.6	Enersis
Endesa	Chile	Celta	Electricity generation			Enersis
Endesa	Chile	CHILECTRA	Electricity distribution		59.5	Enersis
Endesa	Chile	Endesa	Chile		36.4	Enersis

Group	Country	Company	Sector	%	Indirect %	IndirectVia
			Electricity generation			
Endesa	Chile	Enersis	Electricity	60.62		
Endesa	Chile	Pangue	Electricity generation			Enersis
Endesa	Chile	Pehuenche	Electricity generation			Enersis
Endesa	Chile	San Isidro	Electricity generation		27.3	
Enersis						
Endesa	Chile	Taltal Power	Electricity generation		18.2	
Enersis						
Endesa	Colombia	Betania	Electricity generation			
Endesa	Colombia	CODENSA	Electricity distribution		12.6	Enersis
Endesa	Colombia	EMGESA	Electricity generation			Enersis
Endesa	Dominican Republic	CEPM	Electricity	40		
Endesa	Peru	Edegel	Electricity generation		13.8	Enersis
Endesa	Peru	EDELNOR	Electricity distribution	18		
Endesa	Peru	EEP	Electricity generation	60		
Endesa	Peru	Etevensa	Electricity generation	60		
Endesa	Peru	Generandes Peru	Electricity generation		21.7	Enersis
Endesa	Peru	Piura	Electricity generation			

Iberdrola (Spain)

Group	Country	Company	Sector	%	Indirect %	IndirectVia
Iberdrola	Bolivia	Cade	Energy			
Iberdrola	Bolivia	Electropaz	Electricity distribution			
Iberdrola	Brazil	Celpe	Electricity distribution		31.0	Guaraniana
Iberdrola	Brazil	Coelba	Electricity distribution		22.4	Guaraniana
Iberdrola	Brazil	Cosern	Electricity distribution		9.5	Guaraniana
Iberdrola	Brazil	Guaraniana	Electricity	39		
Iberdrola	Brazil	Itapebi	Electricity	40.5		
Iberdrola	Guatemala	Eegsa	Electricity	49		
Iberdrola	Mexico	Altamira III/IV	Electricity generation			
Iberdrola	Mexico	Enertek	Electricity generation			
Iberdrola	Mexico	Femsa-Titan	Electricity generation			
Iberdrola	Mexico	Monterrey	Electricity generation			

Union Fenosa (Spain)

Group	Country	Company	Sector	%	Indir %	IndirectVia
Union Fenosa	Colombia	Electricaribe	Electricity	69.3		
Union Fenosa	Colombia	Electrocosta	Electricity	70.4		
Union Fenosa	Colombia	EPSA	Electricity	64		
Union Fenosa	CostaRica	La Joya	Electricity generation	65		
Union Fenosa	Guatemala	Guatemala Distribuidores	Electricity distribution	80		
Union Fenosa	Mexico	Union Fenosa (Mexico)	Electricity generation	100		
Union Fenosa	Nicaragua	Disnorte	Electricity distribution	79.5		
Union Fenosa	Nicaragua	Dissur	Electricity distribution	79.5		
Union Fenosa	Panama	Chiriqui	Electricity distribution	51		
Union Fenosa	Panama	Metro-oeste	Electricity distribution	51		

EdP (Portugal)

Group	Country	Company	Sector	%	Indir. %	IndirectVia
EdP	Brazil	Aguas do Brasil	Water		10	Aguas de Portugal
EdP	Brazil	Bandeirante	Energy	96.5		
EdP	Brazil	CERJ	Electricity distribution	15		
EdP	Brazil	COELCE	Electricity distribution		4.48	CERJ
EdP	Brazil	EBAL	Water		10	Aguas de Portugal
EdP	Brazil	Enerpeixe	Electricity generation	59		
EdP	Brazil	Enersul	Electricity distribution		21.0	Iven
EdP	Brazil	Escelsa	Energy		38.2	Iven
EdP	Brazil	INVESTCO	Electricity generation	25		
EdP	Brazil	Iven	Finance	73.1		
EdP	Brazil	Prolagos	Water		9.35	Aguas de Portugal
EdP	Guatemala	Eegsa	Electricity distribution	17		

EdF (France)

Group	Country	Company	Sector	%	Indir. %	IndirectVia
EdF	Argentina	Distrocuyo	Energy	20		
EdF	Argentina	EASA	Energy	100		
EDF	Argentina	Edemsa	Energy	45		
EdF	Argentina	Edenor	Electricity	90		
EdF	Argentina	Inversora	Diamante Energy	55		
EdF	Argentina	Inversora Nihuiles	Energy	64.9		
EdF	Brazil	Light	Energy	95		
EDF	Brazil	Norte Fluminense	Electricity generation	90		
EDF	Mexico	Altamira	Electricity	51		
EDF	Mexico	Central Anahuac	Electricity generation	100		
EDF	Mexico	Central Lomas Del Real	Electricity generation	100		
EDF	Mexico	Central Saltillo Electricity generation	100			
EDF	Mexico	Controladora Del Golfo	Electricity generation	100		
EdF	Mexico	Tecate	Energy			
EDF	Mexico	Valle Hermosofid	Electricity generation	100		

Tractebel –Suez (France)

Group	Country	Company	Sector	%	Indir. %	Indirect Via
Tractebel	Argentina	Energy Consulting Services (ECS)	Energy	46.67		
Tractebel	Brazil	Cana Brava	Electricity			
Tractebel	Brazil	Gerasul	Electricity	68		
Tractebel	Brazil	Itasa	Energy		38	Tractebel Brasil
Tractebel	Brazil	Ocirala Participacoes	Energy		100	Tractebel Brasil
Tractebel	Brazil	Tractebel Brasil	Energy	100		
Tractebel	Brazil	Tractebel Energia	Energy	78.3		
Tractebel	Chile	Colbun	Electricity		37.5	Tractebel Andes
Tractebel	Chile	Electroandina	Electricity		33.3	Tractebel Andes
Tractebel	Chile	Inversora Electrica Andina	Electricity	62.5		
Tractebel	Mexico	Tractebel (Monterey)	Electricity generation	80		
Tractebel	Peru	Enersur	Electricity generation	78.95		
Tractebel	Peru	Yuncan	Electricity generation			Enersur

AES (USA)

Group	Country	Company	Sector	%	Indir.%	Indirect Via
AES	Argentina	AES (Argentina)	Energy			
AES	Argentina	AES (San Nicolás)	Electricity generation	88		
AES	Argentina	AES Parana	Electricity generation	100		
AES	Argentina	Central Dique	Electricity generation			
AES	Argentina	Edelap	Electricity distribution	90		
AES	Argentina	Eden	Electricity distribution	90		
AES	Argentina	Edes	Electricity distribution	90		
AES	Argentina	Gener-TermoAndes	Electricity generation	99		
AES	Argentina	Hidroelectrica Alicura	Electricity generation	100		
AES	Argentina	Quebrada de Ullum	Electricity generation	100		
AES	Argentina	Rio Juramento	Electricity generation	98		
AES	Argentina	San Juan (Argentina)	Electricity generation	98		
AES	Australia	Destec (Australia)	Electricity generation	20		
AES	Brazil	AES Sul	Electricity	98		
AES	Brazil	CEMIG	Electricity	21.6		
AES	Brazil	Eletronet	Telecomms	51		
AES	Brazil	Eletropaulo	Electricity distribution 68			
AES	Brazil	Tiete	Electricity generation	52		

AES	Brazil	Uruguaiana	Electricity generation	100		
AES	Chile	Gener	Electricity generation	99		
AES	Colombia	Colombia I	Electricity generation	69		
AES	Dominican Republic	AES Andres	Electricity generation	100		
AES	Dominican Republic	EDEES	Electricity distribution	50		
AES	Dominican Republic	Itabo	Electricity generation	25		
AES	Dominican Republic	Los Mina	Electricity generation	100		
AES	El Salvador	CAESS	Electricity distribution	75		
AES	El Salvador	CLESA	Electricity distribution	64		
AES	El Salvador	Deusem	Electricity distribution	74		
AES	El Salvador	EEO	Electricity distribution	89		
AES	Honduras	AES Honduras	Electricity generation			
AES	Mexico	Merida III	Electricity generation	55		
AES	Panama	AES Panama	Electricity generation	100		
AES	Panama	Chiriqui hydro	Electricity generation	49		
AES	Panama	EGE Bayano	Electricity generation		49	AES Panama
AES	Panama	EGE Chiriqui	Electricity generation		49	AES Panama
AES	PuertoRico	AES (Puerto Rico)	Electricity generation	100		
AES	Venezuela	EDC	Energy	86		

CMS Energy (USA)

Group	Country	Company	Sector	%	Indir. %	IndirektVia
CMS Energy	Argentina	Arroyito	Electricity generation	30		
CMS Energy	Argentina	CT Mendoza	Electricity generation	90		
CMS Energy	Argentina	EDEERSA	Electricity distribution	90		
CMS Energy	Argentina	El Chocon	Electricity generation	17.2		
CMS Energy	Argentina	Ensenada	Electricity generation	100		
CMS Energy	Argentina	GasAtacama	Gas transmission	50		
CMS Energy	Argentina	TGM	Gas transmission	20		
CMS Energy	Argentina	TGN	Gas transmission	30		
CMS Energy	Argentina	YPF-La Plata	Electricity generation	100		
CMS Energy	Brazil	CPEE	Electricity distribution	82		
CMS Energy	Chile	Taltal Power	Electricity generation			
CMS Energy	Jamaica	Jamaica Private Power	Electricity generation	43		
CMS Energy	Venezuela	SENECA	Electricity distribution	49		

El Paso (USA)

Group	Country	Company	Sector	%	Indir:%	Indirect Via
El Paso	Argentina	CBA	Electricity generation	7.8		
El Paso	Argentina	CBA	Electricity generation		6.12	Costanera
El Paso	Argentina	Costanera	Electricity generation	12		
El Paso	Brazil	Manaus Power	Electricity generation	100		
El Paso	Brazil	Rio Negro Power	Electricity generation	100		
El Paso	Mexico	Samalayuca Power	Electricity generation	40		
El Paso	Peru	Aguaytia	Electricity generation			
El Paso	Peru	Aguaytia	Pipeline and Power Energy	24.04		

PSEG (USA)

Group	Country	Company	Sector	%	Indir. %	Indirect Via
PSEG	Brazil	RGE	Electricity distribution	30.25		
PSEG	Chile	Aguas Quinta	Water		13.5	Chilquinta Energia
PSEG	Chile	Chilquinta Energia	Electricity distribution	49.9		
PSEG	Chile	Energas	Gas distribution		45	Chilquinta Energia
PSEG	Chile	Frontel	Electricity	81.5	100	Saesa
PSEG	Chile	Saesa	Electricity	100		
PSEG	Peru	Luz del Sur	Electricity	38		
PSEG	Venezuela	Turboven	Electricity	50		

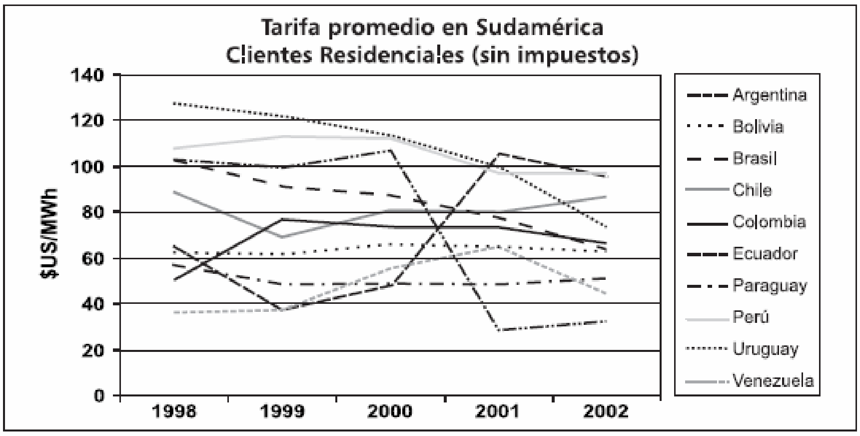
11.5 Annex 5 – Electricity tariffs for private, commercial and industrial sectors

Las Tarifas Eléctricas en los Países de la CIER 1998-2002

Tarifas Residenciales

Valores promedio en dólares/MWh

		Año				
		1998	1999	2000	2001	2002
Argentina	sin impuesto	103	100	107	29	32
	con impuesto	141	137	144	41	46
Bolivia	sin impuesto	63	62	66	65	63
	con impuesto	69	71	-	-	-
Brasil	sin impuesto	103	91	88	77	64
	con impuesto	130	100	117	96	80
Chile	sin impuesto	89	70	81	80	87
	con impuesto	106	82	95	94	103
Colombia	sin impuesto	51	77	73	74	66
	con impuesto	51	77	73	74	66
Ecuador	sin impuesto	65	38	48	105	95
	con impuesto	80	42	63	118	113
Paraguay	sin impuesto	57	48	49	49	51
	con impuesto	62	53	54	53	56
Perú	sin impuesto	108	113	112	97	97
	con impuesto	127	133	126	115	115
Uruguay	sin impuesto	127	122	114	100	74
	con impuesto	157	150	140	123	94
Venezuela	sin impuesto	36	37	55	65	45
	con impuesto	36	37	56	67	45



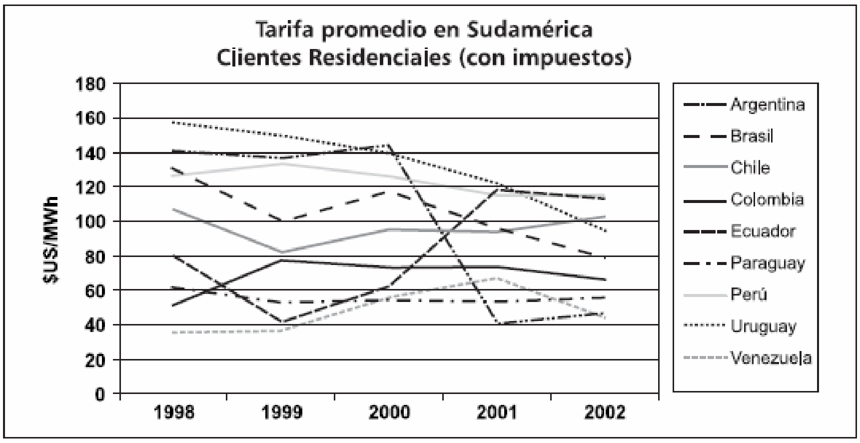
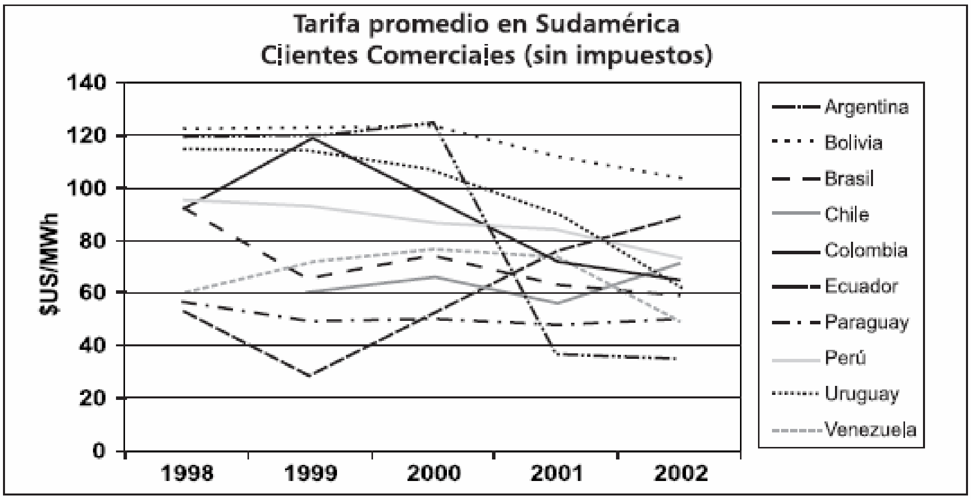


Figure: Electricity tariffs from 1998 until 2002 for the private sector (in US $ / MWh; without “sin impuesto” and with “con impuesto” taxes)

Tarifas Comerciales

Valores promedio en dólares/MWh

		Año 1998	1999	2000	2001	2002
Argentina	sin impuesto	120	120	125	37	35
	con impuesto	160	165	153	52	47
Bolivia	sin impuesto	122	123	124	112	104
	con impuesto	-	-	-	-	-
Brasil	sin impuesto	92	65	74	63	59
	con impuesto	118	81	90	83	73
Chile	sin impuesto	-	60	66	56	72
	con impuesto	-	72	77	66	85
Colombia	sin impuesto	93	119	96	72	65
	con impuesto	98	119	96	72	68
Ecuador	sin impuesto	53	28	53	76	89
	con impuesto	75	37	65	99	117
Paraguay	sin impuesto	57	49	50	48	51
	con impuesto	63	54	56	53	56
Perú	sin impuesto	95	93	87	84	73
	con impuesto	111	110	98	99	86
Uruguay	sin impuesto	115	115	107	90	63
	con impuesto	115	115	107	90	80
Venezuela	sin impuesto	60	72	77	73	49
	con impuesto	69	84	88	86	53



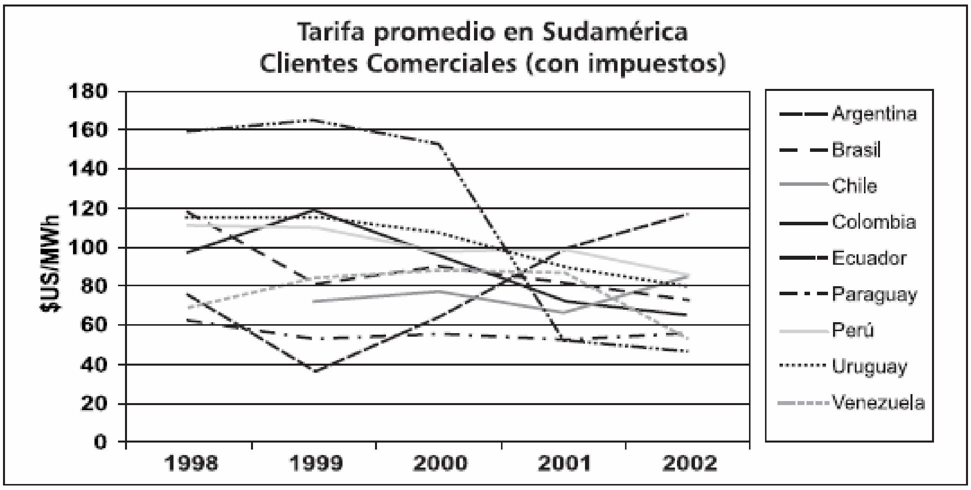
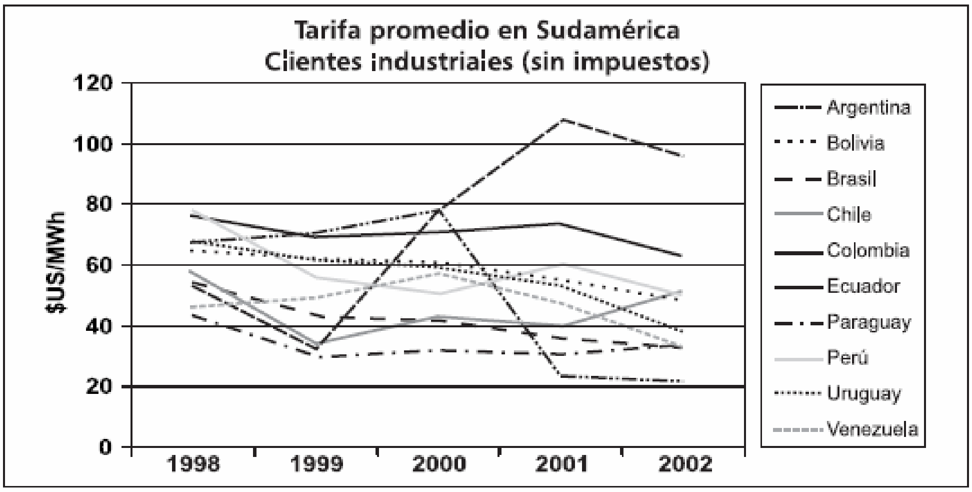


Figure: Electricity tariffs from 1998 until 2002 for the commercial sector (in US $ / MWh; without "sin impuesto" and with "con impuesto" taxes)

Tarifas Industriales

Valores promedio en dólares/MWh

		Año				
		1998	1999	2000	2001	2002
Argentina	sin impuesto	68	71	78	24	22
	con impuesto	87	93	104	33	31
Bolivia	sin impuesto	65	62	61	55	48
	con impuesto	71	72	-	-	-
Brasil	sin impuesto	54	43	42	36	33
	con impuesto	64	52	52	44	40
Chile	sin impuesto	57	34	43	40	52
	con impuesto	67	40	51	45	61
Colombia	sin impuesto	76	69	71	74	63
	con impuesto	78	69	75	74	63
Ecuador	sin impuesto	54	33	78	108	96
	con impuesto	70	38	102	133	122
Paraguay	sin impuesto	44	30	32	31	34
	con impuesto	49	32	35	34	37
Perú	sin impuesto	78	56	51	60	50
	con impuesto	89	66	61	71	60
Uruguay	sin impuesto	68	62	60	53	38
	con impuesto	68	62	60	53	48
Venezuela	sin impuesto	46	49	57	47	33
	con impuesto	53	57	65	56	39



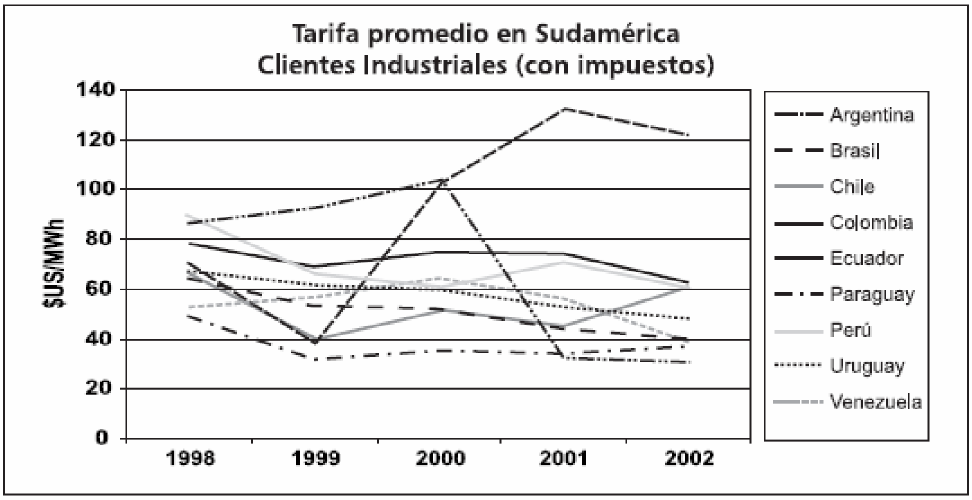


Figure: Electricity tariffs from 1998 until 2002 for the commercial sector (in $ / MWh; without "sin impuesto" and with "con impuesto" taxes)

11.6 Annex 6 - Kyoto Mechanisms

United Nations General Assembly took a decision on the protection of the global climate in the interests of the present and future generation of 19 December 1991. According to this decision the UN Framework Convention on Climate Change became effective in the year 1995. The United Nations Framework Convention on Climate Change (UNFCCC) was adopted on May 9, 1992. The Convention divides countries into two groups: those listed in Annex I ("Annex I Parties") and those not listed (so-called "non-Annex I Parties"). The Annex I Parties consists of developed countries and countries with "economies in transition" (known as EITs), that are, the Russian Federation and several other Central and Eastern European countries [21] .

The Parties to the UNFCCC adopted the Kyoto Protocol on December 11, 1997 at the third Conference of the Parties (COP-3). In order to enter into force, the Protocol needed to be ratified by at least 55 parties to the convention, including the Annex I (industrialised) countries responsible for 55 % of Annex I countries' emissions in 1990. Russia, which accounts for 17 %, became the key to Kyoto after the U.S. pull out. At the time of writing[22] 128 parties had submitted their instruments of ratification[23]. The receipt of the Russian Federation's instrument of ratification by the United Nations Secretary-General has started the 90-day countdown to the Kyoto Protocol's entry into force. The Kyoto Protocol will enter into force on the 16 February 2005.

In the Protocol, Annex I parties to the UNFCCC have agreed to a number of commitments with a view to reducing their overall emissions of the six greenhouse gases [24] (GHGs) by at least 5% below 1990 levels between 2008 and 2012. The process of determining each country's target was not based on scientific or economic measures, but represented in part on what individual countries were prepared to offer.

The European Union established its own "bubble" within its membership and voluntarily offered to reduce its emissions by 8%. For example, within the EU bubble Ireland and Portugal are allowed to increase their emissions significantly whereas Germany and Denmark will make major reductions.

The US accepted 7%, Canada, Hungary, Japan and Poland agreed on 6% and Russia, Ukraine and New Zealand accepted stabilisation, i.e 0%. As a result of special pleadings, Norway is allowed to increase its emissions by 1%, Australia by 8% and Iceland by 10%.

In Articles 6, 12 and 17 of the Kyoto Protocol, what are now known as the Kyoto Mechanisms, were defined with a view to permitting some flexibility in the ways Annex I parties might achieve their agreed reductions. The three mechanisms allow credit to be gained from action taken in other Parties:

- Joint Implementation (JI) to allow emissions trading from projects between Annex I countries; and

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[21] The countries listed in Annex I are as follows: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, UK and USA.

[22] December 2004

[23] http://unfccc.int

[24] carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6)

- Clean Development Mechanism (CDM) to allow developing countries without reduction targets to benefit from emission reduction projects, and to allow developed countries to obtain emission reduction credits for projects in developing countries.
- International Emissions Trading (IET) to allow emissions trading between developed countries;

The three mechanisms are described in detail below.

The Kyoto Protocol broke new ground with its three innovative "mechanisms." The mechanisms aim to reduce the costs of curbing emissions by allowing Parties to pursue opportunities to cut emissions more cheaply abroad than at home. The cost of curbing emissions varies considerably from region to region as a result of differences in, for example, energy sources, energy efficiency and waste management. It makes economically sense to cut emissions where it is cheapest to do so, given that the impact on the atmosphere is the same.

However, there have been concerns that the mechanisms could allow Parties to avoid taking climate change mitigation action at home, confer a "right to emit" on certain Parties, or lead to exchanges of fictitious credits, which would undermine the Protocol's environmental goals. The negotiators of the Protocol and Marrakesh Accords therefore sought to design a system that fulfilled the cost-effectiveness promise of the mechanisms, while addressing concerns about environmental integrity and equity.

11.6.1 Joint Implementation

Joint implementation allows Annex I Parties to implement projects that reduce emissions, or increase removals by sinks, in the territory of another Annex I Party. The emission reduction units (ERUs) generated by such projects can be used by Annex I Parties to help meeting their emission targets. While the term "joint implementation" does not appear in Article 6, it is often used as convenient shorthand.

A Joint Implementation project might involve, for example, replacing a coal-fired power plant with a more efficient combined heat and power plant or reforesting land. In practice, Joint Implementation projects are most likely to take place in Annex I Parties with economies in transition, where there tends to be more scope for cutting emissions at low cost.

Joint Implementation projects must have the approval of all Parties involved, and must lead to emission reductions or removals that are additional to any that would have occurred without the project. Sink projects, i.e. activities absorbing carbon from the atmosphere and fixing it in plants, soil and other organic matter, must conform to the Protocol's wider rules on the land use, land-use change and forestry sector. Each Annex I country was allocated a number of tons of carbon uptake that it could count towards its emissions target from forest management activities.

Annex I Parties are to refrain from using ERUs generated from nuclear energy to meet their targets. Projects starting from the year 2000 that meet the above rules may be listed as Joint Implementation projects. However, ERUs may only be issued in relation to periods from 2008 onwards.

11.6.2 Clean Development Mechanism

The Clean Development Mechanism (CDM) allows Annex I Parties to implement projects that reduce emissions in the territory of a non-Annex I Party. The certified reduction units (CERs) generated by such projects can be used by Annex I Parties to help meet their emissions targets while the projects also help non-Annex I Parties to achieve sustainable development and contribute to the ultimate objective of the Convention. The project must deliver real, measurable and long-term emission reductions that are additional to any that would have occurred anyway. CERs created in the pre-commitment period from 2000 to 2007 can be banked for use by the Annex I country in fulfilling its commitments.

A CDM project might then involve, for example, a rural electrification project using solar panels or the reforestation of land. As with joint implementation projects, Annex I Parties are to refrain from using CERs generated through nuclear energy to meet their emission targets.

Consistent with the Bonn Agreement, the Marrakech Accords limit sinks projects in the CDM to afforestation. Conservation projects are explicitly excluded. In the first commitment period, Annex I Parties' use of CERs from such projects is limited to an amount equal to 1 % of their assigned amount. The specific rules for sinks projects in the CDM are to be adopted at COP9, based on a recommendation from the SBSTA.

The CDM is a 'baseline-and-credit' system where emission reductions are calculated based on a comparison with the baseline situation, also called reference scenario, which outlines what would have happened in the absence of the project activity. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A and anthropogenic removals by sinks within the project boundary.

A baseline shall be established:

- On a project-specific basis and/or using a multi-project emission factor;
- In a transparent manner with regard to the choice of approaches, assumptions, methodologies, parameters, data sources and key factors;
- Taking into account relevant national and/or sectoral policies and circumstances, such as sectoral reform initiatives, local fuel availability, power sector expansion plans, and the economic situation in the project sector;
- In such a way that CERs cannot be earned for decreases in activity levels outside the project activity or due to force majeure;
- Taking account of uncertainties and using conservative assumptions.

Baseline of CDM Projects should be the most appropriate of the following:

- Existing actual or historical emissions, as applicable
- Emissions from technology that represents economically attractive course of action, taking into account barriers to investment
- The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 % of their category

The CDM is expected to generate investment in developing countries, especially from the private sector, and promote the transfer of environmentally friendly technologies in that direction. However, the finance and technology transfer commitments of Annex II Parties under the Convention and Kyoto Protocol are separate and remain valid. Furthermore, public funding for CDM projects must not result in the diversion of official development assistance.

11.6.3 Emission trading

Through emissions trading, Annex I Parties may acquire assigned amount units (AAUs) from other Annex I Parties that find it easier, relatively speaking, to meet their emissions targets. This enables Parties to utilise lower cost opportunities to reduce emissions, irrespective of the Party in which Party those opportunities exist, in order to lower the overall cost of reducing emissions. Similarly, Annex I Parties may also acquire ERUs (from joint implementation projects), CERs (from CDM projects) or RMUs (from sink activities) from other Annex I Parties. Transfers and acquisitions of these units are to be tracked and recorded through national registries (see below).

In order to address the concern that Annex I Parties could "over-sell" and then be unable to meet their own emission targets, each Party is required to hold a minimum level of ERUs, CERs, AAUs and/or RMUs in their national registry. This is known as the commitment period reserve. It is calculated as 90% of the Party’s assigned amount, or as the level of national emissions indicated in the Party’s most emissions inventory (multiplied by five, for the five years of the commitment period), whichever is the lower figure. Parties may also authorise legal entities to participate in emissions trading.

Ultimately, after the commitment period has finished, the check to ensure that Annex I Parties are in compliance with their emissions targets will take place by comparing each Parties emissions during the commitment period with their holdings of ERUs, CERs, AAUs and RMUs. These holdings, as well as transfers and acquisitions, will be tracked and recorded through a computerised system of registries. There are three components to the registry system:

- A national registry will be established and maintained by each Annex I Party. This will contain accounts for holding the ERUs, CERs, AAUs and RMUs by the Party, as well as by any legal entities authorised by the Party to hold them. It will also contain accounts for setting units aside for compliance purposes (retirement) and removing units from the system (cancellation). Transfers and acquisitions between account holders or between Parties will take place through these national registries.
- A CDM registry will be established and maintained by the executive board of the CDM. This will contain CER accounts for non-Annex I Parties participating in the CDM.
- A transaction log will be established and maintained by the secretariat. This will verify transactions of ERUs, CERs, AAUs and RMUs as they are proposed, including their issuance, transfer and acquisition between registries, cancellation and retirement. If any transaction is found not to be in order, the registry is required to stop the transaction.

At COP 7 in Marrakech (November 2001) parties made some important decisions regarding tradable emissions units. Annex I countries will be allowed to bank from one commitment period to the next any assigned amount units (AAUs) that they do not need to meet their target. Banking of emissions reduction units (ERUs) and certified emissions reductions (CERs) generated under JI and the CDM, respectively, is limited to 2.5 % of a Party's initial assigned amount, a generous limit that few are likely to reach. Each Party will be required to retain emissions units in a commitment period reserve (CPR) of an amount equal to 90% of its allowable emissions or five times its most recently reviewed emissions inventory, whichever is lower. The CPR was designed to address the risk of overselling. A new unit was created for sinks credits generated in Annex I countries. These units, referred to as removal units or RMUs, must be used in the commitment period in which they are generated and cannot be banked for future commitment periods. However, this limitation is of little practical consequence because CERs, AAUs, ERUs, and RMUs are, with a few exceptions, interchangeable.

11.6.4 Monitoring, Reporting and Review

The Marrakech Accords outline how a country must calculate and record its annual emissions. Utilising best practice standards from the Intergovernmental Panel on Climate Change (IPCC), each country's national system should ensure that the quality of "carbon credits" entering the market will be sound. Adjustments will be made in cases where countries have underestimated their emissions. As mentioned above, in cases where the inventories are poor, the country will not be allowed to enter the carbon market.

World Bank and EBRD have already created such Fund instruments that by financing of CDM projects also target on generation of tradable CERs.

11.7 Annex 7 – Characteristics of Gas Turbines

	Model	ISO Based Load (kW)	Heat rate Btu/kW-hr	LHV efficiency (%)	Budget price ($)	$ per kW
Solar Turbine	Titan 130	13,500	10,250	33.3	4,700,000	348
Rolls Royce	Trent 60	58,000	8,370			
Pratt&Whitney	FT8 PowerPac	27,970	8,900			
Rolls Royce	Avon	14,580	12,100	28.2	5,175,000	355
GE Power System	LM6000 Sprint Intercooler	47,300	8,250	41.4	14,100,000	259
Alstom Power	GT 8C	52,800	9,920	34.4	15,100,000	285
Alstom Power	GT8C2	57,200	9,750	35.0	19,100,000	281
Siemens	V64.3A	68,000	9,690	35.2	16,500,000	262
Alstom Power	GT11N2	114,500	9,780	34.9	22,800,000	200
Siemens	W501D5A	122,480	9,730	35.1	24,500,000	200
Siemens	V94.2	159,000	9,890	34.5	29,890,000	188
Alstom Power	GT13E2	165,100	9,550	35.7	33,850,000	205
Alstom Power	GT24	183,000	8,910	38.3	36,400,000	199
Siemens	W501F	186,160	9,066	37.6	37,000,000	199
Siemens - Westinghouse	V94.3A	190,000	9,375	36.4	36,100,000	190
Siemens - Westinghouse	W501G	243,500	8,700	39.2	46,000,000	189
Alstom Power	GT26	265,000	8,895	38.4	50,350,000	190
MHI	M701F	270,300	8,930	38.2	50,275,000	186
MHI	M701G	334,000	8,630	39.5	60,120,000	180
GE Power System	PG9351 (FA)	255,600	9,250	36.9	48,560,000	190

	Model	ISO Based Load (kW)	Heat rate Btu/kW-hr	LHV efficiency (%)	Budget price ($)	$ per kW
GE Power System	PG6101 (FA)	70,150	9,980	34.2	20,000,000	285

Table: Gas Turbine Characteristics and Budget Price Levels (Source: Gas Turbine World (January - February 2002)

	Plant Model	ISO Based Load (MW)	LHV efficiency (%)	Nº Gas Turbines	Budget price ($)	$ per kW
GE Power System	S-206FA	218.7	54.1	2xMS60016FA	103,000,000	471
GE Power System	S-109FA	390.8	56,7	1xMS9001FA	139,100,000	356
Alstom Power	KA26-1	393.0	58.5	1xGT26	140,500,000	358
Alstom Power	KA13E2.2	485.7	53.2	2xGT13E2	166,000,000	342
Alstom Power	KA 10C-1	41.28	51.1	1xGT10C		
Siemens Power Generation	1S.V94.3A	392.20	57.4	1xV94.3A		
Siemens Power Generation	2 V94.3A	783.90	57.3	2xV94.3A		
MHI	MPCP2 (M701G)	981.90	58.9	2xM701G		
MHI	MPCP1 (M701G)	489.30	58.7	1xM701G		
MHI	MPCP2 (M701F)	799.60	57.3	2xM701F	236,900,000	296

	Plant Model	ISO Based Load (MW)	LHV efficiency (%)	Nº Gas Turbines	Budget price ($)	$ per kW
MHI	MPCP2 (M701F)	397.70	57.0	1xM701F	139,200,000	350
GE Power System	S209FA	786.90	57.1	2xMS9001FA	242,100,000	308
GE Power System	S109H	480.00	60.0	1xMS9001H		
Siemens Power Generation	1S.V94.2A	294.30	55.1	1xV94.2A		
Siemens Power Generation	2S.V94.2A	587.60	55	2xV94.2A		

Table: Combined Cycle Characteristics and Budget Price Levels (Source: Gas Turbine World January - February 2002)