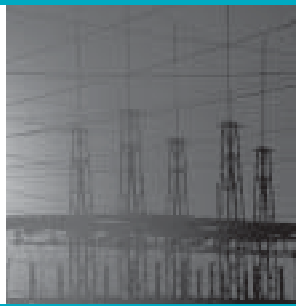
ESMAP Technical Paper 123/09

Latin America and the Caribbean Region Energy Sector – Retrospective Review and Challenges







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ESMAP

Energy Sector Management Assistance Program

Energy Sector Management Assistance Program (ESMAP)

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Latin America and the Caribbean Region Energy Sector – Retrospective Review and Challenges

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Energy Sector Management Assistance Program

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Units of Measure

bbl	barrel
bcf	billion cubic feet
bcfd	billion cubic feet per day
bn	billion
bn bbl	billion barrel
Boe	barrel of oil equivalent
Bpd	barrels per day
BTU	British thermal unit
cu ft	cubic feet
GW	giga watt
GWh	giga watt (s) per hour
ha	hectare
kJ	kilo joules
kcal	kilo calorie
km	kilometer
kV	kilo volt
kW	kilo watt (s)
kWh	kilo watt (s) per hour
l	liter
m	meters
m^2	square meter
MMBTU	million British thermal unit

mmcfd	million cubic feet per day
mn	million
mn bbl	million barrels
mn l	million liter
MW	mega watt (s)
MWh	mega watt (s) per hour
t	tons
Tcf	trillion cubic feet = 10^{12} cubic feet
TJ	tera joule

Abbreviations and Acronyms

1P	Proven
2P	Proven and probable
3P	Proven, probable and possible
AFBC	Atmospheric Fluidized Bed Combustion
AIDS	Acquired Immune Deficiency Syndrome
ANCAP	Administración Nacional de Combustibles, Alcohol y Portland de Uruguay
ANEEL	Agencia Nacional de Energía Elétrica
AOM	Administration, Operation and Maintenance
ARPEL	Asociación Regional de Empresas de Petróleo y Gas Natural en Latinoamérica y el Caribe (Association of Latin American and Caribbean Petroleum Companies)
ASI	Integral and Systematic Conservation Program
BCIE	Banco Centroamericano de Integración Económica (Central American Bank for Economic Integration)
BID	Banco Interamericano de Desarrollo
BNDES	Brazilian National Development Bank
BP	British Petroleum
CAF	Corporación Andina de Fomento
CAMMESA	Compañía Administradora del Mercado Mayorista Eléctrico S.A.
CariBank	Caribbean Development Bank
Caricom	Caribbean Community
CCEE	Cámara de Comercializa çã o de Energía Elétrica
CCGT	Combined Cycle Gas Turbine
CCTs	Clean Coal Technologies

CDM	Clean Development Mechanism
CDEC	Sitio Oficial del Centro de Despacho Económico de Carga
CDEC-SIC	Sitio Oficial del Centro de Despacho Económico de Carga del Sistema Interconectado Central
CEMIG	Companhia Energetica de Minas Gerais S.A.
CENACE	Centro Nancional de Control de Energía
CEPAL	Comisión Económica para América Latina y el Caribe
CFE	Comision Federal de Electricidad
CFE-PAESE	Electricity Conservation Program
CFL	Compact Fluorescent Lamps
CIDA	Canadian International Development Agency
CNE	Comisión Nacional de Energía (National Energy Commission)
CNG	Compressed Natural Gas
COES	Comité de Operación Económica del Sistema Interconectado Nacional
CONAE	La Comisión Nacional para el Ahorro de Energía (National Commission for Energy Conservation)
COPEL	Companhia Paranaense de Energia
CRE	Comisión Reguladora de Energía (Energy Regulatory Commission)
CREG	Comisíon de Regulación de Energía y Gas
CREDP	Caribbean Renewable Energy Development Program
CRESESB	Centro de Referência para as Energias Solar e Eólica Sérgio de Salvo Brito
CRIE	Regional Electrical Interconnection Commission
CUREN	Energy Conservation and Rational Use Program
DC	Direct Current
DoE	Department of Energy
DEA	Ministry of Energy and Mines, Alternative Energy Office
Discoms	Distribution Companies
DSE	Ministry of Environment and Energy, Sectoral Energy Office
EAP	East Asia and the Pacific (World Bank regional vice presidency)
EC	European Commission
ECA	Europe and Central Asia (World Bank regional vice presidency)
ECGP	Eastern Caribbean Gas Pipeline
ECGPC	Eastern Caribbean Gas Pipeline Company

ECLAC	Economic Commission for Latin America and the Caribbean
EdF	Electricité de France
EE	Energy Efficiency
EIA	Energy Information Administration
ENAP	Empresa Nacional del Petróleo de Chile
ENARSA	Empresa Nacional de Energía S.A.
ENDESA	Empresa Nacional de Electricidad S.A.
ENEE	Empresa Nacional de Energía Eléctrica
ENRE	Ente Nacional Regulador de Electricidad
E&P	Exploration and Production
EPE	Empresa de Pesquisas Eléctricas
EPM	Empresas Públicas de Medellín
EOR	Regional System Operator
Esco	Energy Service Company
ESMAP	Energy Sector Management Assistance Program
EU	European Union
FENERCA	Financiamiento de Empresas de Energía Renovable (Facilitating Financing for Renewable Energy Program)
FERUM	Fondo de Electrificación Rural y Urbana Marginal
FIDE	Fideicomiso para el Ahorro de Energía Eléctrica (Electricity Conservation Trust Fund)
FOMIN	Fondo Multilateral de Inversiones
FY	Fiscal Year
G-8	Group of Eight
GDP	Gross Domestic Product
GEF	Global Environment Facility
Gencos	Generation Companies
GHG	Greenhouse Gas
GNEA	Gasoducto Noreste Argentina
GNI	Gross National Income
GT	Gas Turbine
GTZ	Deutsche Gesellschaft für Technische Zusammenarbeit (German Agency for Technical Cooperation)

HIV	Human Immunodeficiency Virus
IADB/IDB	Inter-American Development Bank
IBRD	International Bank for Reconstruction and Development (of the World Bank Group)
ICE	Instituto Costarricense de Electricidad
ICSID	International Center for Settlement of Investment Disputes (of the World Bank)
IDA	International Development Association (of the World Bank Group)
IDC	Interest During Construction
IEA	International Energy Agency
IFC	International Finance Corporation (of the World Bank Group)
IFI	International Financial Institution
IGCC	Integrated Gasification Combined Cycle
IIRSA	Initiative for Regional Infrastructure Integration of South America
IMF	International Monetary Fund
INMETRO	National Institute of Metrology, Standardization and Industrial Quality
IOC	International Oil Company
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
ISA	Interconexión Eléctrica S.A.
ISO	Independent System Operator
LAC	Latin America and the Caribbean (World Bank regional vice presidency)
LAFRE	Ley para el Aprovechamiento de las Fuentes Renovables
LCR	Latin America and the Caribbean Region
LCSEG	Latin America Energy Cluster
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MAE	Mercado Atacadista de Eletricidade
MEIP	Mesoamerican Energy Integration Program
MENA	Middle East and North Africa (World Bank regional vice presidency)
MER	Regional Electricity Market
MIGA	Multilateral Investment Guarantee Agency (of the World Bank Group)
MoU	Memorandum of Understanding

MSC	Multiple Service Contract
MSD	Medium-speed Diesel
NGE	Net Gas Exporters
NGO	Nongovernmental Organization
NOC	National Oil Company
NOE	Net Oil Exporter
NOI	Net Oil Importer
NOP	Non Oil Producing
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OLADE	Organización Latinoamericana de Energía
O&M	Operation and Maintenance
ONS	Operador Nacional do Sistema Elétrico
OSINERG	Organismo Supervisor de Inversión en Energía
PAE	Energy Saving Program
PAEPRA	Programa de Abastecimiento Eléctrico a la Población Rural Dispersa de Argentina (Program for Electricity Supply to the Rural Population of Argentina)
PBE	Brazilian Labeling Program
PCA	PetroCaribe Accord
PDVSA	Petróleos de Venezuela S.A. (Venezuelan Petroleum Company)
PERMER	Proyecto de Energía Renovable en el Mercado Eléctrico Local
PPA	Power Purchase Agreement
PPI	Private Participation in Infrastructure
PPP	Public-Private Partnership
PROCEL	National Program for Energy Conservation
PRODEEM	Programa para o Desenvolvimento da Energía nos Estados e Municípios (Program for Energy Development of States and Municipalities)
PROINFA	Programa de Incentivos a las Fuentes Alternativas de Energía Eléctrica
PRONACE	National Energy Conservation Program
PRONASOL	Programa Nacional de Solidaridad
PRONER	National Rural Electrification Program
PROURE	Program for the Rational and Efficient Use of Energy

R&D	Research and Development
RE	Renewable Energy
RoE	Return on Equity
R:P	Reserve to Production Ratio
SAR	South Asia (World Bank Regional Vice Presidency)
SENER	Prospectiva del Sector Eléctrico
SHS	Solar Home Systems
SIC	Sistema Interconectado Central
SIEPAC	Sistema de Interconexión Eléctrica para los Países de América Central
SIGET	Superintendencia General de Electricidad y Telecomunicaciones
SOE	State-owned Enterprise
SSPD	Superintendence of Public Services
ST	Steam Turbine
T&D	Transmission and Distribution
Transcos	Transmission Companies
TERNA	Technical Expertise for Renewable Energy Applications
UCTE	Union for the Co-ordination of Transmission of Electricity
UNDP	United Nations Development Programme
UPME	Ministry of Mines and Energy, Mining, Energy Planning Unit
URE	Rational Energy Use Program
USAID	U.S. Agency for International Development
USDoE	United States Department of Energy
UT	Unidad de Transacciones
VAT	Value Added Tax
WDI	World Development Indicators
WTI	West Texas Intermediate
YPF	Yacimientos Petrolíferos Fiscales
YPFB	Yacimientos Petrolíferos Fiscales Bolivianos

Chemical Symbols

CO_2	carbon dioxide
NO_2	nitrogen dioxide
SO_2	sulfur dioxide

Foreword

During the 90s, most countries in Latin America and the Caribbean Region (LCR) supported by the World Bank, implemented a market-oriented reform in the energy sector to promote competition, economic regulation and greater private sector participation, as the main instruments to improve the quality, reliability and efficiency of energy services, improve the government's fiscal position and increase affordable access to modern energy services for the poor. Some countries were successful in achieving these objectives. However, after a series of financial and economic crises, corporate fiascos and electricity market failures in the region and around the world, combined with substantial increases in international oil prices, the reforms experienced difficulties and, currently, many LCR countries are facing new challenges to meet future energy demand. These challenges include a drop in private investment and flight of private investors, dependency on oil imports, vulnerability to high oil prices, political opposition and dissatisfaction with privatization and liberalization policies, incomplete reforms, and difficulties in ensuring access to affordable energy services for the poor. In many countries, State-owned companies still own and operate a sizeable portion of energy supply facilities and face well known governance and efficiency problems.

Although competition, privatization and good governance are still important instruments to meet the overarching goal of ensuring sufficient, efficient and sustainable energy supply, it is clear that the energy strategy of the 90s has to be adapted to the new realities and challenges faced by the region. These are mainly to enhance energy security and support the development of clean energy, improve access to energy services for the poor, mobilize the financial resources required to meet the power sector investment needs, and improve the governance and institutional framework of the sector. The World Bank needs to revise its energy strategy for LCR to help the countries face these new challenges.

This Report comprises an assessment of the energy sector reform in the region: its achievements, difficulties, lessons learnt and current status; an assessment of the future needs of the energy sector investment and financing requirements, constraints and challenges; and a review of the role of development agencies in supporting the region's energy needs. The study is not a systematic analysis of the reform experience and needs of individual countries, which is not deemed necessary to define an energy strategy for the region, but rather an analysis of the main themes that are common to most countries, with reference to specific cases of individual countries, based on a review of the documentation available on the reform, and on current energy plans. The Report presents the findings and conclusions on these three main topics with a view to use them in the formulation of a new energy strategy of the World Bank in the region.

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The process included two retreats of the Latin America Energy Cluster(LCSEG). A first retreat, held in June 2006, discussed the scope of work, while an early draft was discussed during the second retreat held in January 2007. The retreats benefited also from the valuable participation of a group of invitees; namely, Mr. Jamal Saghir, Mr. Makhtar Diop, Ms. Laura Tuck, Mr. Charles Feinstein, Mr. Junhui Wu, Mr. Tonci Bakovic, Ms. Anna Wellenstein and Mr. Franz Drees-Gross. Special thanks to Ms. Marjorie K. Araya and Ms. Ananda Swaroop for editing and producing the report in its final format.

Executive Summary

The 90s was the most propitious period for launching privatization and governance programs in the energy sector. The former Soviet Union had collapsed and, with it, the economic model that advocated the "commanding heights" role of the State and its institutions. Concurrently, from their lowest level in 1986 of some US$11 / barrel (bbl), oil prices recovered modestly over the next few years to more viable levels, but remained relatively stable between US$18-22 / bbl throughout the 90s. In this environment, reform and privatization programs in the energy sector were undertaken in several countries in the LCR, some of which were implemented with enthusiasm, given the recognition that increased reliance on markets was a more efficient way to manage the sector. However, the results of the reforms have been varied, since they require sustained political commitment, and that the economic and social benefits of the reforms help win the support of a wide cross-section of the society.

The global energy environment today has changed significantly compared to the 90s, when the momentum for capital flows to the developing world was at its height. Currently, the new energy demand poles of China and India have compounded the pressure on oil and gas prices, while the security of energy supply and climate change have become major new issues on an already heavy energy agenda. Supply security and climate change issues are being addressed through the following initiatives in the LCR, in which the World Bank Group and private sector would partner as appropriate:

- More investments in large and medium hydro and other RE resources, such as wind and biomass;
- Increased participation of high efficiency gas-fired thermal generation;
- Measures to enhance oil and gas exploration and development in the region's prospective basins;
- Major investments to increase cross-border gas trade in the Southern Cone, between Colombia and República Bolivariana de Venezuela (referred to hereafter as Venezuela), in Central America and the Eastern Caribbean;

- In the larger markets, such as Mexico, Brazil and Chile, investments are planned to import Liquefied Natural Gas (LNG) as part of strategies to diversify their dependence on single sources of gas;
- Promotion of enhanced EE programs; and
- Continue the diversification of the fuel supply mix in thermal power generation which satisfies least-cost and risk criteria. However, in some countries, this would result in coal-fired plants emerging, and a substantial effort would be required to introduce Clean Coal Technologies (CCTs) to reduce carbon dioxide (CO_2) impacts.

The Evolution of the Electricity Sector in LCR

In most countries, the reforms of the electricity sector in the 90s were motivated by the poor performance of a public model where the State was policy maker, regulator, investor and monopoly provider of electricity supply service. Lack of incentives for efficiency in the operation and expansion of the sector, and the politicization of policy decisions and management of sector utilities resulted in high electricity losses and Administration, Operation and Maintenance (AOM) costs, investments in generation that did not respond to least-cost principles, relatively low electricity coverage, electricity tariffs that did not reflect economic costs, difficulties in mobilizing the financial resources required for the expansion of the power system, poor reliability of service and recurrent financial losses of State-owned Enterprises (SOEs) that finally were reflected on unsustainable fiscal deficits.

Most countries in LCR progressed in the 90s to the most advanced stages of competition and privatization in a market-oriented reform of the power sector. Separation of roles, unbundling, competition and private participation were used as main instruments to increase efficiency, improve the government's fiscal position and increase access to electricity service for the poor. Even the few countries (Mexico, Venezuela, Costa Rica, Uruguay, Paraguay and the small islands in the Caribbean) that decided to keep vertically integrated monopolies, introduced reforms to facilitate the participation of private Independent Power Producers (IPPs) (Table 1).

Power sector reforms based on competitive wholesale markets or single buyer schemes were very effective in mobilizing private capital for generation capacity. The new investors preferred CCGT and Medium-speed Diesels (MSDs), generation technologies characterized by relatively low capital costs, high efficiency and short construction periods – a combination of factors that helped reduce project, market and country risks. These technologies also took advantage of low price natural gas or residual fuel oil to minimize generation costs.

During the last 15 years, electricity supply and demand in the region had a substantial transformation. Electricity demand increased at an annual rate of growth of 4.5 percent. The generation capacity was expanded to about 100,000 mega watt(s) (MW), of which

Table 1: Power Sector Reform in LCR

% Demand	*1%*	*33%*	*47%*	*18%*	
Unbundling, Wholesale Power Market, Large Consumers		Ecuador	Brazil, Colombia, Dominican Republic, El Salvador, Guatemala, Nicaragua	Argentina, Bolivia, Chile, Panama, Peru	65%
Single Buyer & IPPs		Guyana	Trinidad & Tobago, Honduras	Jamaica	2%
Vertically Integrated Monopoly and IPPs	Uruguay	Costa Rica, Mexico	Suriname		24%
No Competition	Paraguay	Venezuela, R.B. de		Most Island States	9%
	SOE	Low	Medium	High	% Demand
		Private Participation			

Competition

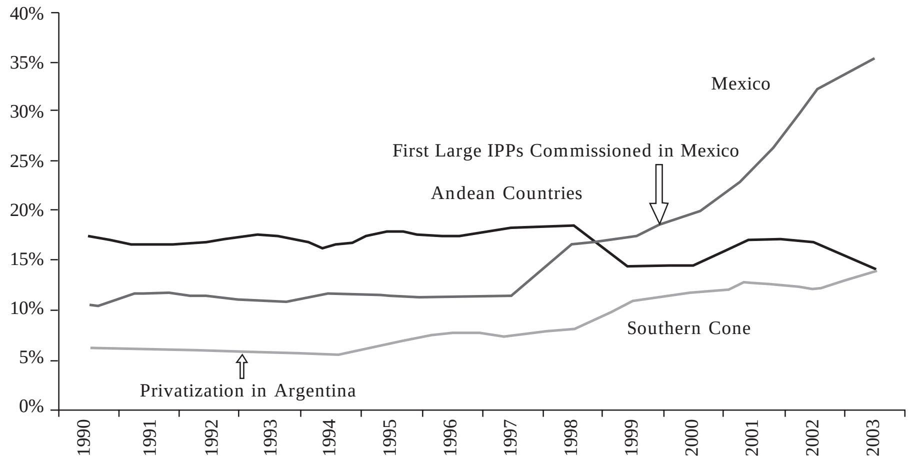
Source: Authors´ calculations based on 2005 data.

52,000 MW was in conventional thermal plants. Electricity generation became more dependent on fossil fuels, mainly natural gas in Mexico and the Southern Cone, and residual and diesel oil in Central America and the Caribbean, used in thermal plants developed by private investors (Figures 1 and 2).

Although, in some countries, the expansion of thermal capacity helped to achieve a more balanced hydro/thermal generation mix, less vulnerable to droughts, it created its own problems. Most countries, dependent on imported fuels, and that relied on diesel engines (Central America, the Caribbean) or CCGT (Chile), became vulnerable to high and volatile oil prices or to gas supplied from a single source. This situation brought serious consequences: the impact of high and volatile fuel prices on generation costs could not be passed through to tariffs due to political constraints, creating serious financial problems for governments, Distribution Companies (Discoms) and IPPs; and the disruption in gas supply threatened the security of energy supply.

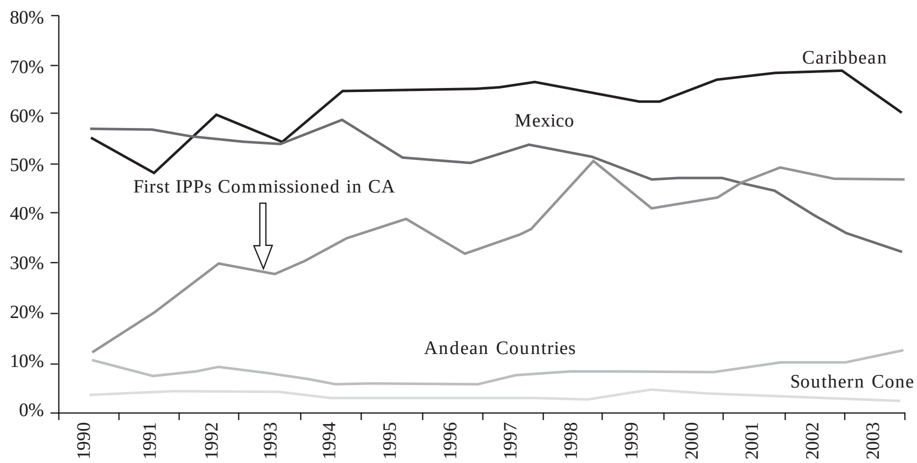
During the past 10 years, when most reforms took place, the energy sector in the region has been exposed to external shocks that were a severe test for the reforms: economic crises in large countries like Brazil, Argentina and Colombia in 1998-2002, severe droughts in 1997-2001 in countries that depend on hydro generation (Brazil, Chile, Colombia), 200 percent increase in the price of crude oil in 1999-2006, the Enron corporate scandal and the failure of the California power market.

Figure 1: LCR – Natural Gas Generation (% of total generation)



Source: The World Bank-World Development Indicators (WDI) database.

Figure 2: LCR – Oil Generation (% of total generation)



Source: The World Bank-WDI database.

Assessment of the Reform

The assessment focuses on an analysis of its impact on the main drivers of the reform (efficiency and quality of service, fiscal impact and affordable access for the poor) and a review of new issues and main lessons learnt.

IMPACT ON MAIN DRIVERS

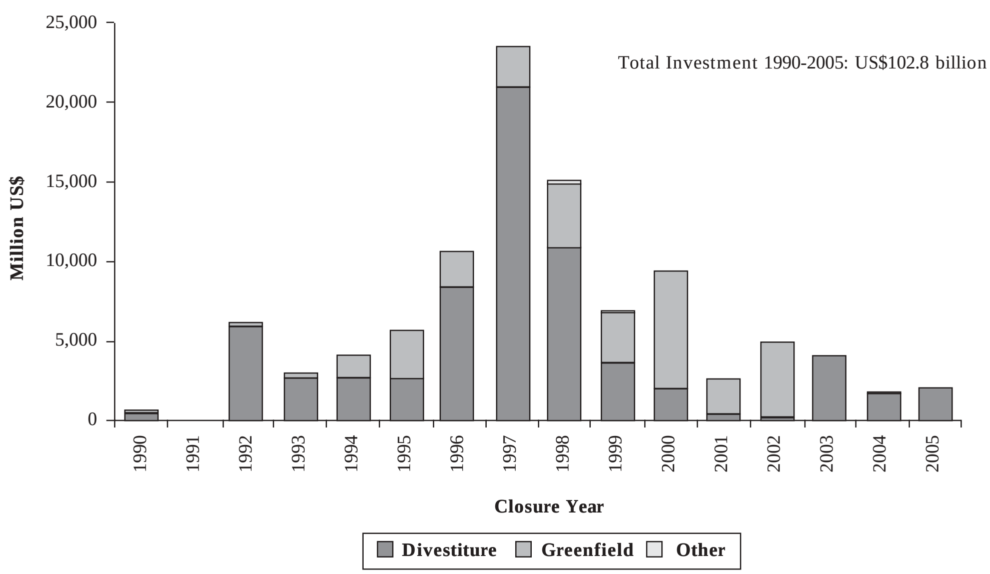
In many countries, the combination of private participation, competition and better regulation was effective in improving productive efficiency and quality of service. Wholesale electricity prices in Argentina and Chile decreased by 40 percent in real terms during the first 10 years of the reform. The availability of thermal plants increased from 48 percent to 77 percent in Argentina. The efficiency of the thermal generation system in the Dominican Republic and Honduras increased more than 20 percent. A group of privatized Discoms in Argentina, Brazil, Chile, Colombia and Peru improved labor productivity by more than 100 percent, and reduced distribution losses by about 50 percent. The analysis of a large sample of about 84 privatized Discoms shows that, on an average, the improvements were less impressive but still substantial: 38 percent increase in labor productivity, 10 percent reduction in losses and 14 percent increase in quality of service.

The power sector reform in the region had a substantial positive fiscal impact. During the past 15 years, private investment in electricity in LCR amounted to about US$103 bn, about 60 percent in divestiture of public assets, and 40 percent in greenfield projects. Investments in divestiture peaked at about US$21 bn at the time of the privatization of major distribution assets in Brazil, and almost vanished by 2002 (Figure 3). Investments in greenfield projects (mainly generation projects and, lately, some transmission) have been more stable during the past 10 years.

Some private investors experienced difficulties due to financial crises and lack of government commitment. Due in part to these problems, about 17 percent of total private investment in 1990-2005 is in the distress category or has been cancelled. About 55 percent of the private investment in Argentina, amounting to US$9 bn, has requested international arbitration after the substantial financial losses of electricity companies during the economic crisis of 2001. Most private investment in the Dominican Republic and Guyana was cancelled after the withdrawal of international operators of Discoms, who did not find an enabling environment to reduce electricity losses and improve collections.

Although private companies have a high market share in Generation, Transmission and Distribution (T&D) in many countries, the public sector still maintains a substantial

Figure 3: LCR – Annual Investment in Electricity Projects with Private Participation



Source: The World Bank, Private Participation in Infrastructure (PPI) database.

presence. Private investors control more than 50 percent of generation and distribution in about 10 countries that advanced more in their market reform and privatization program. However, hydroelectric generation is still, by and large, in the hands of SOEs in most Central American countries and in Brazil; transmission is a strategic activity assigned to SOEs in Central America and is controlled by SOEs in Colombia and Brazil; and SOEs still control about 50 percent of distribution in Brazil, Argentina and Colombia. Additionally, SOEs control electricity service in countries that did not advance in privatization (Venezuela, Mexico, Costa Rica, Ecuador, Paraguay and Uruguay).

Poor people benefited from a substantial increase in electricity coverage, better quality of service and the application of social tariffs during the reform. Electricity coverage in LCR increased from about 75 percent to 90 percent in 1992-2005, which represents about 156 million (mn) new people with electricity service. Poor people living in urban slums benefited from improvements in quality and safety of service related to investments in the formalization of illegal connections. New laws and regulations in many countries established social tariffs with explicit subsidies aimed to provide affordable electricity service to low-income and vulnerable groups.

However, the evidence shows that, in many countries, poor people were not the main beneficiaries of the substantial improvements in productive efficiency, the rebalancing of tariffs and the application of social tariffs:

- In some countries, industrial and high-income residential consumers were the main beneficiaries of lower wholesale prices achieved through competition and the rebalancing of tariffs, which reduced substantial cross-subsidies of the pre-reform period. In Argentina, electricity prices for industrial and high-income residential consumers dropped by about 50 percent, while low-income residential consumers saw only a 2 percent reduction. In Colombia, industrial tariffs were reduced by 44 percent, and tariff surcharges for high-income residential consumers were reduced from 100 percent to 20 percent, while subsidies for low-income groups only increased from 40 percent to 45 percent;
- It is estimated that in Greater Buenos Aires consumer welfare increased by 17 percent for the richest electricity consumers, while it decreased by 10 percent for the poorest;
- It is also true that privatization and cost-covering tariffs ensured the financial viability of efficient electricity providers, which were able to expand access and improve quality of service to a large number of consumers in urban and peri-urban areas, including poor people; and
- Although substantial progress was made to reduce tariff distortions and nontransparent electricity subsidies, some of the reforming countries still apply social tariff schemes that are poorly targeted (Honduras, Guatemala), and favor mostly middle-income people.

ISSUES AND LESSONS

The retrenchment of private investment by 2002 is associated to external shocks but is also the result of flaws in market design and implementation. The slowdown followed the same pattern of total private capital flows to the region and can be explained by external factors: the conclusion of major divestiture programs in the region; the financial losses of key investors after the economic crisis in Argentina in 2001; the Enron scandal; and the loss of economic value of power utilities in developed countries. However, the drop of private investment and the flight of private investors from the region were exacerbated when some countries did not meet the conditions to attract and maintain private investment: adequate tariff levels and collection discipline, stable and enforceable contracts and regulations, and minimum government interference. Some of the regulatory and market problems were:

- **The vulnerability of markets to external shocks prompted government interventions that undermined the credibility of reforms**. The threat of large tariff increases and energy shortages have prompted government intervention to change market rules and control prices, which undermined the authority of regulatory institutions and the credibility of government commitments, and increased the risk for private investors. In Argentina, the government breached the terms of the concession contracts when it froze electricity tariffs after a maxi-devaluation in 2001. Governments in the Dominican Republic, Nicaragua, Honduras and Guatemala did not allow the impact of high fuel prices on generation costs to pass-through to tariffs;

- **New market models demanded strong institutions, political commitment and market conditions that were not available in many countries**. Experienced international operators decided to pull out as shareholders of Discoms in the Dominican Republic and Guyana, when it was clear that they lacked political support to enforce payment discipline. The transition to cost-covering tariffs was not completed in some countries due to lack of political will to rebalance tariffs. New and weak regulatory institutions in some countries were captured by service providers or consumer groups. El Salvador had to change a flawed market design based on unbundling and retail competition in a small and highly concentrated 1,000 MW generation system. Private generators operating in the market saw that their investments were at risk by the change in rules and held back on new investments; and

- **The IPP option based on long-term Power Purchase Agreements (PPAs) was effective in mobilizing private capital in the transition to new competitive markets but experienced serious difficulties.** In the Dominican Republic, Central America and Colombia, there was a mounting political pressure to renegotiate with the IPPs when the price of energy increased substantially or when the IPPs were no longer competitive in the new wholesale markets, and the offtaker had to assume the stranded costs.

Addressing the problem of low electricity access to the poor in rural areas requires substantial investment subsidies and strong government support. There are still 50 mn people, almost all poor and in rural areas, without electricity. Private investors were effective in connecting consumers in urban and rural areas near the power grid but reluctant to extend access to rural areas where the service is not financially viable. In Bolivia and Nicaragua, two countries that privatized distribution, only 30 percent of rural households have access to electricity. In Chile, a leader in reform and privatization, the government provided investment subsidies of about US$1,500 / household to increase electricity coverage in rural areas from 62 percent to 92 percent in 1995-2005.

Wholesale power markets have been complemented with mandatory long-term contracts to ensure sufficient generation capacity to meet demand. After experiencing serious energy shortages in 1998-99 and 2001, Chile and Brazil were concerned that the market rules and wholesale prices did not provide sufficient incentives to private investors to expand generation capacity. These market problems prompted legislative reforms to establish the obligation to contract the long-term supply of a major portion of expected demand of the regulated market by competitive bidding procedures. Long-term contracts are effective instruments to hedge price risks, mitigate market power in the spot market and facilitate financing of new investments, but pose new challenges to avoid the risks and inefficiencies of central planning.

Lack of good institutional and economic governance (rule of law, regulatory quality and corporate governance) is still a problem in many countries. Although many countries performed well in designing and operating regulatory authorities, government interference, weak technical competence and lack of transparency in the application of general principles undermined the credibility of government commitment to the reform. Although corporate governance was improved with privatization of electricity services, many SOEs still face the problem of weak corporate governance and poor performance. Most of the large countries in the region were classified in the second quartile in key worldwide governance indicators (rule of law and corruption).

The assessment shows that many countries in the region face new problems and unresolved issues to meet future energy demand:

- Drop of private investment and flight of private investors;
- Dependency on oil imports for power generation and vulnerability to high oil prices, mainly in Central America and the Caribbean;
- Political opposition and dissatisfaction with privatization and liberalization policies;
- In some countries like Argentina, Ecuador, Honduras, Nicaragua and the Dominican Republic, the financial viability of the power sector is at risk by electricity tariffs that lag behind supply costs due to external shocks or lack of political will to make necessary tariff adjustments;
- Lack of good corporate governance and poor performance of SOEs is still a problem in countries like the Dominican Republic, Honduras, Ecuador and Colombia. SOEs have limited internal generation of funds to finance required investments;

- In several countries, regulatory institutions are weak or lack credibility due to government interference and interventions in the market, or to difficulties in building technical competence; and
- The legitimacy of reform was undermined in some countries when the poor were not clearly the beneficiaries of the reform, and electricity access to the poor in rural areas is still low.

Assessment of Future Needs and Challenges

The future investment needs of the sector were assessed based on a consolidation of recent electricity expansion plans prepared by the planning authorities in the main countries in the region. The Report identifies the main challenges faced by the electricity sector in the region, taking into account the future needs and the unresolved issues.

In the next 10 years, the region needs to install about the same generation capacity that was added during the past 15 years. The region is projecting a demand growth of 4.8 percent per year, which means that a net increase of about 100,000 MW in generation capacity will be required, of which about 60,000 MW is new capacity that is not under construction and has not been contracted. Mexico and the Southern Cone account for about 80 percent of the new capacity.

There is renewed interest in the region for the development of clean energy. In response to the prospects for high oil prices in the long term, dependence on imported fuels and concerns about climate change, many countries are giving priority to the development of the large potential of clean energy (medium and large hydroelectric power plants, mini-hydros, wind power, biomass, geothermal, biofuels, gas-fired thermal generation and EE and energy conservation programs). With current and projected oil prices, most of these technologies and programs are commercially viable, provided that the right incentives and policies are put in place:

- **The installed capacity in small renewable power is expected to double in 2006-15,** from 6,800 MW to 12,800 MW (in Brazil, Costa Rica, Honduras, Chile and Mexico). This capacity can increase substantially if adequate incentives for the development of renewable power are established in more countries;
- **Medium and large hydroelectric and gas-fired power generation account for 93 percent of clean power to be installed during the next decade**;
- **There is ample room for improving EE**. The successful experience of Mexico indicates that savings of about 15 percent of peak electricity demand are possible with adequate price levels and well designed EE programs based, among others, on the enactment of efficiency legislation, application of norms, financing of projects, labeling of appliances and equipment, dissemination of information and the promotion of Energy Service Companies (Escos); and

- **Many countries in LCR**, especially low-cost sugarcane producers besides Brazil, **are embracing a mandatory mix of gasoline and bio-ethanol** for environmental and energy security reasons, and a 10 percent ethanol blend is feasible in tropical countries.

Diversification of energy sources is important for the region. Effective diversification improves energy security, can reduce generation costs, mitigate the volatility of oil prices, and reduce vulnerability to external shocks**.** Diversification not only comprises development of clean energy, including imported LNG and pipeline natural gas, and promoting regional energy trade but, also, development of coal-fired generation:

- **Clean energy is cost-competitive** in many countries in the region based on an oil price scenario of about US$60 / bbl. While the levelized generation costs for oil-based thermal generation are about US$85 / mega watt(s) per hour (MWh), for the clean energy options they are in the range of US$35 to 75 / MWh at late 2006 prices (Figure 4);

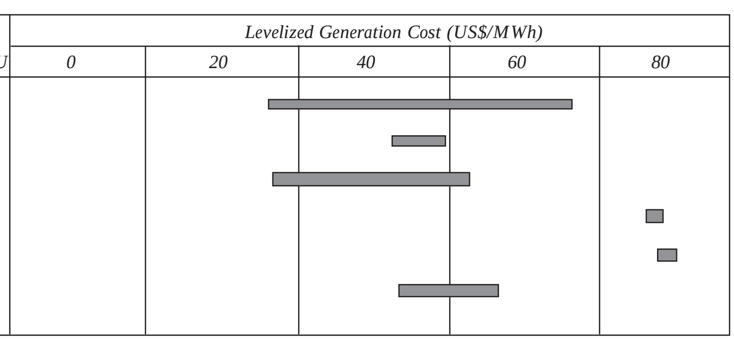
- **Countries with access to natural gas continue to rely on thermal expansion based on gas-fired Gas Turbine (GT) and CCGT,** which contribute about 32 percent of new generation capacity**.** Although this appears to be a least-cost generation expansion strategy, it may not minimize risks. Except for Peru and Bolivia, which have ample reserves, the other countries face the risk of constraints in the supply of pipeline gas or the risk of volatile and high LNG prices indexed to Henry Hub;

- **Countries with a large hydroelectric generation potential continue to rely on the development of medium and large hydroelectric projects**, which represent about 46 percent of new generation capacity to be installed in the region during the next decade;

- **Coal-fired generation is an attractive least-cost option to mitigate the risk of volatile oil prices.** LNG prices are tracking those of crude oil. Coal is the only conventional fuel whose price has remained decoupled from that of oil but also its price ranges from 50-60 percent less than that of gas, which compensates for higher investment costs, including the use of CCTs. Levelized generation costs for coal plants are in the range of US$50 to 57 / MWh; and

Figure 4: LCR – Typical Levelized Generation Costs

Energy-type	*Plant Factor*	*Fuel Price Range US$/MMBTU*
Hydro	50%	
Coal Steam Turbine	70%	1.1-2-2
CCGT	60%	1.8-6.7
Oil Steam Turbine	60%	6.6
Diesel Engines	60%	6.6
Wind Power	30%	



Source: Authors' calculations.

- **There are opportunities to restore confidence in cross-border energy trade and expand regional interconnections**. Recent difficulties in the Southern Cone energy market revealed the risks of dependency on a single source of energy supply and the need to strengthen energy markets in the region. Reinforcing the gas pipeline network in the Southern Cone would contribute to restoring confidence and enhancing energy security in the subregion. The power interconnection between Colombia and Central America is a good complement to the Central American interconnection (Sistema de Interconexión Eléctrica para los Países de América Central – SIEPAC) and the Mexico-Guatemala interconnection (to be commissioned by 2009). A new power interconnection between Uruguay and Brazil would be useful in diversifying supply options and promoting electricity trade in the Southern Cone.

The implementation of a diversification or clean energy policy poses some regulatory challenges. In countries with competitive wholesale markets, the generation expansion decisions taken by the market agents may not be aligned with the diversification policy, especially in the case of private investors that want to maximize profits and manage risks. Energy diversification and improved energy security may result in higher energy supply costs. The idea is not to diversify at any cost by fiat, but to establish incentives and constraints that promote the implementation of this policy by independent agents who take least-cost investment decisions responding to price and policy signals. Furthermore, the regulatory framework should ensure that the generation costs that result from the application of competitive procedures can be passed through to tariffs (a competitive spot market or competitive bidding for long-term contracts).

Mobilizing the financing resources required to meet the investment needs of the electricity sector represents a major challenge, but creates new opportunities, now that most countries face a more difficult investment climate to attract private capital:

- **It is estimated that in 2009-15, the region would have to invest about US$20 bn per year** in new generation, T&D projects. This amount is about five times the private investment that was mobilized for greenfield projects in the past eight years;

- An annual investment of about US$11 bn in generation is required, of which about US$8 bn is in projects which entail higher investment costs, longer construction periods, and longer payback periods (hydro, coal-fired thermal and geothermal), a **combination of factors that increases project and market risks for a private developer and makes these projects unsuitable for nonrecourse project finance**;

- **Private participation is needed to finance a substantial portion of the investment needs**. Countries that did not reform continue relying on private participation in generation (Mexico and Honduras in IPPs, Costa Rica in small renewable projects). Countries with large private participation in the power sector need to provide adequate incentives to keep incumbent private companies investing in the expansion of the power system. All countries need to attract new investors to replace those that left the region;

- **Substantial public sector involvement would be required to finance the investment needs in the region, subject to fiscal space constraints**. SOEs in Brazil, Colombia, Costa Rica, Honduras and Mexico will maintain active participation in the development of hydro resources, probably in partnership with private investors. SOEs that provide T&D services need to have sufficient internal generation of cash to finance new investments; and

- **Mobilizing domestic private capital is important** to finance investment needs. Domestic investors are in a better position than foreign investors to manage the country and market risks of selling electricity, a political commodity with revenues in local currency, and are also willing to do so. For example, private pension funds had a key role in the privatization of the electricity sector in Chile, and are a source of financing in the domestic corporate bond market for private and State-owned utilities in Chile and Colombia; strategic domestic investors have participated in the development of generation projects in Brazil and Honduras, and in the divestiture of medium-sized Discoms in Colombia.

- **Improving access to energy services for the poor is a major challenge, especially in countries with low rural coverage.** Bolivia, Nicaragua and Honduras, countries with rural electricity coverage of about 30 percent, would have to invest about US$25 mn per year each, to double coverage in rural areas by 2015. This will require the intervention of the public sector to efficiently allocate substantial investment subsidies funded by cross-subsidies, direct subsidies and grants, and to promote the use of RE to provide energy services to remote populations, where extension of the grid is too expensive.

Although competition and private participation are still important instruments to improve performance, the energy strategy of the 90s needs to be adjusted to address the main challenges faced by the region to meet the overarching goal of ensuring a sufficient, efficient and sustainable energy supply during the next 10 years: enhance energy security, mobilize the financial resources required to meet investment needs, improve access to energy services for the poor, and improve the governance and institutional frameworks:

- **To enhance energy security, it is needed to facilitate the development of hydroelectric projects** and other generation projects by private investors, step up the carbon finance program (development of renewable power), promote regional energy trade, and support the development of clean coal generation technologies in the region;

- **Mobilizing private financing would require the use of private financing models that fit the country and project risks, and improvements in the regulatory climate and the financial viability of SOEs, which allow private investors to have an adequate risk-adjusted return on investment**. There is a wide range of financing models to allocate to market risks, depending on the project and country conditions; from virtually no risk under management contracts (used in countries with weak governance) to most risks under full divestiture or greenfield projects operating in a competitive market (used in countries with strong institutions and projects with moderate risks – CCGT, GT and MSD generation plants). Private development of capital-intensive generation projects (hydroelectric and coal-fired plants) need a public-private partnership (PPP) arrangement that helps manage higher project and market risks: the private partner brings the best management practice and technical expertise and secures funding, and the public partner secures timely granting of licenses and permits, facilitates implementation of the environmental mitigation plan, provides guarantees and other forms of credit enhancement to reduce the project, market and country risks. However, none of these models is sustainable or appropriate without credible commitments to improve the regulatory regime and the financial viability of the sector (for example, tariff adjustments and enforced payment discipline). If these minimum requirements are not met, there is always a risk that the PPP becomes a fiscal burden for the government;

- **To increase electricity coverage to 95 percent by 2015, an investment of about US$14 bn in rural distribution is needed during the next 10 years**, which should be financed mainly with investment subsidies and grants. It is needed to step up the support to development of rural energy programs; and
- **Improving corporate governance of SOEs and consolidating the market reforms are high priorities** for a sustainable improvement in the performance of the power sector in the region. However, many of the schemes tried in the past to improve performance of SOEs short of privatization have failed (contract plans, commercialization, corporatization, twining contracts and management contracts). Successful cases of corporatization and participation of domestic shareholders in SOEs (the case of Interconexión Eléctrica S.A. [ISA] in Colombia) or improved management contracts could be tried in other countries willing to engage.

Consolidation of reforms comprises improving technical competence and independence of regulatory institutions, which is essential to build legitimacy and restraint government interference, and implementing second generation reforms, including new schemes and procedures to efficiently contract long-term energy supply to mitigate price risks and facilitate financing of new generation investment.

Overall, the region's energy strategy supports the new Clean Energy policy adopted by the World Bank, but poses some challenges. Most countries in the region are developing clean energy (hydroelectric power, small renewable power, gas-fired generation, biofuels and EE) mainly to meet demand growth at least cost and enhance energy diversification. The expansion of medium and large hydroelectric and gas-fired thermal generation capacity would account for about 93 percent of new clean power capacity additions in the region during the next decade and would require strong financing support for capital-intensive hydroelectric and cross-border gas transmission projects. The generation expansion plans in many countries also call for an increase in the participation of small RE in the energy matrix, and support will be required to buy down the production costs of some technologies that are not cost-competitive as the externalities of all energy options are not properly valued.

The participation of clean energy in the generation mix is very high as compared to developed countries, and will increase from 72.8 percent in 2005 to 73.8 percent by 2015. The paradox is that countries like Costa Rica and Brazil, that depend on hydro generation and promote clean energy, may increase their emission factor (total CO_2 emissions per kilo watt[s] per hour [kWh]) twofold in 2005-14, due to the impact of new CCGT and other small additions of thermal capacity. Only Mexico, dependent on thermal generation and with a high initial emission factor, will be able to reduce it with an aggressive program to substitute natural gas for liquid fuels in power generation.

However, some countries with limited access to natural gas or to low-cost hydro power, would have to consider the development of new coal-fired plants as an option to diversify energy sources and reduce the level and volatility of generation costs. This is the case of Central American countries, large island states in the Caribbean, north of Chile, Uruguay and south Brazil. The development of coal-fired plants in the context of the Clean Energy policy is a challenge that would require World Bank support to promote the use of CCTs including, in the near future, Integrated Gasification Combined Cycle (IGCC) plants.

Oil and Gas Sector Developments in LCR

Challenges and Assessment of Reform

In Argentina and Bolivia, both State oil and gas companies, Yacimientos Petrolíferos Fiscales **(YPF) and** Yacimientos Petrolíferos Fiscales Bolivianos **(YPBF), respectively, were privatized**. However, the economic crisis in Argentina at the beginning of this decade, and the accompanying social and economic dislocation, created a dire situation. Artificially low oil and gas prices accelerated demand, and the lack of resources to invest resulted in the country being unable to meet either internal gas demand or its export gas commitments to Chile, resulting in rationing. This was an important setback in the efforts to deepen and expand cross-border trade, and highlights the importance to rebuild confidence and trust in such trade. This is critical if competitively priced gas is to continue to play a role in addressing climate change issues; reducing dependence on high-cost volatile oil; and resurrecting the belief that cross-border gas trade can enhance energy security in the Southern Cone. Compounding these developments, in 2004, the government created a new State-owned company (Empresa Nacional de Energía S.A. – ENARSA) for the production and sale of oil, gas and electricity in sectors that had been privatized a decade earlier.

In Bolivia, the recent nationalization of the assets of foreign oil companies and the re-emergence of the State-owned YPBF illustrate, once more, the fragility of reforms in certain social and political settings. Additionally, these developments have raised questions about the scale of International Oil Company (IOC) operations in the country and the sources of investment resources for the sector.

In contrast, the approach to reform and liberalization followed in Brazil, Colombia and Peru was more pragmatic and is yielding more sustainable results. In these cases, there was a successful separation of the institutional, contractual and regulatory roles of the State from the investment, production and commercial responsibilities of the State oil company. This has resulted in both private and State-owned companies expanding their operations and investing in new projects. In these three countries, State companies compete for exploration acreage with private operators. The outcome has been clearly positive; the number of contracts signed over the past two years by the State regulatory oil and gas agencies have increased significantly, as have the commitments for exploratory work. Though these countries do not possess the most prospective sedimentary basins, they have still been able to attract foreign private partners.

At the corporate level, the success of Petrobras is important. The company has achieved a high level of technical expertise and in deep offshore technology, can stand shoulder to shoulder with the leading IOCs. It has increased oil and gas production significantly and, in the near future, Brazil is expected to achieve oil self-sufficiency. In addition, the company's shares were placed on the market, with the government retaining a 51 percent share. This last measure has enhanced not only corporate accountability, but has contributed to capital market development by beginning to make access to one of the country's key sectors available to the Brazilian investor.

Today's oil and gas realities are very different to those of the 90s, which implies that new strategies are called for. Less than 15 percent of the world's oil and gas resources belong to IOCs and, in most regions of the world with significant petroleum resources and a strong sense of national interest, it has become increasingly politically difficult for the State to surrender further ownership over these resources to IOCs, since currently these are viewed as strategic resources from both national and global perspectives. As such, since National Oil Companies (NOCs) will continue to play a role, the issue for the World Bank Group becomes which countries wish to modernize, commercialize and corporatize their NOCs and are ready to engage with the World Bank Group to effect this strategy, which requires a separation of the institutional, contractual and regulatory roles of the State from the investment, production and commercial responsibilities of the NOC.

In this context, despite the very tough conditions being imposed on the foreign oil companies in Venezuela, Bolivia and Ecuador, some of the players have chosen to remain. This highlights the complexity of the process, given the scale of oil and gas as well as heavy oil resources at stake. Indeed, it is likely that once the negotiation wave is completed, the commitments for E&P would start to increase among those players that have remained.

Given the changed environment in the oil and gas sector globally, an issue which has arisen is the introduction of more flexible oil and gas taxation regimes, when new contracts are being negotiated. The objective is to have regimes that are able to cope better with volatile prices, ensuring more acceptable conditions for operating in different price environments, and a more stable contractual framework. The present painful process of renegotiation of contracts taking place in LCR and other petroleum areas of the world, focusses on contracts drafted originally with fixed royalties and taxes rates.

Retail Petroleum Product Prices

Retail petroleum product subsidies are of particular concern in net oil exporting countries, where diesel and gasoline heavy subsidies set inefficient price signals and fiscal pressures. Retail diesel oil and gasoline prices in November 2006 were reviewed for the seven Net Oil Exporters (NOEs) and the 14 Net Oil Importers (NOIs). It was confirmed that price subsidies concern primarily the NOEs and not the NOIs. Diesel oil was subsidized in all of the NOEs to varying degrees, while gasoline was not subsidized in Argentina, Colombia and Mexico. The extreme case of subsidization was Venezuela in which both products were virtually free, with retail prices of US¢2 and 3/liter (l) for diesel oil and gasoline, respectively. In Trinidad and Tobago, subsidies are also high, reaching about 60 percent and 40 percent for diesel and gasoline, respectively. Among the 14 NOIs, gasoline is not subsidized, with the lowest retail price in Nicaragua (US¢67/l and the highest in Peru (US¢122/l). In the case of diesel oil, subsidies ranging from 3-15 percent existed in Costa Rica, Guatemala, Nicaragua and Panama.

Oil and Gas Production and Consumption

Between 1998-2004, there was a significant overall decline in crude oil production of some 850,000 bbls/day in Venezuela, Argentina and Colombia – the second, third and fourth largest NOE producers in the LCR. These declines were somewhat offset by overall production increases of 550,000 bbls/day in Mexico, Ecuador, Trinidad and Tobago and Bolivia. **This resulted in total crude oil production for the seven NOEs decreasing by about 3 percent (about 300,000 bbls/day) over this period.**

In contrast, crude oil production in the NOIs increased by 39 percent (about 570,000 bbls/day) between 1998-2004, driven primarily by the surge in Brazilian production. This meant that, during the period, total LCR production merely rose by some 3 percent (270,000 bbls/day).

In terms of consumption of petroleum products in the period, among the NOEs, the only significant increases were in Trinidad and Tobago (59 percent on a small base) and Venezuela 23 percent, with reductions in Argentina (-4 percent) and Colombia (-7 percent) and a 1 percent increase in Mexico. In the NOIs, growth in product consumption was modest, being less than 10 percent in nine countries (Barbados, Brazil, Chile, Cuba, Peru, Suriname, Jamaica, Panama and Uruguay), with increases of 26-28 percent in Honduras and Costa Rica, and 48 percent in the Dominican Republic.

In contrast with crude oil, dry natural gas production in the LCR rose to 16,440 million cubic feet per day (mmcfd) in 2004 which implied a 37 percent increase (4,435

mmcfd) from 1998, with 90 percent of this increase coming from the three Net Gas Exporters (NGEs) – Argentina (1,480 mmcfd), Bolivia (675 mmcfd) and Trinidad and Tobago (1,830 mmcfd). Of the three gas-producing net importers (Brazil, Chile and Mexico), Brazil witnessed a 67 percent increase (375 mmcfd) and Mexico, with its large production base, a 16 percent rise (540 mmcfd). Among the six gas-producing nonimporters (Barbados, Colombia, Cuba, Ecuador, Peru and Venezuela), there was a modest decline in Colombia (-2 percent) with larger decreases of -13 percent in both Venezuela and Cuba.

In tandem with the rapid expansion of gas production, natural gas consumption underwent similar rapid growth between 1998-2004, with the three gas-producing net importers, Brazil, Mexico and Chile, experiencing explosive growth on large bases of 200 percent (1,110 mmcfd), 39 percent (1,360 mmcfd) and 160 percent (495 mmcfd), respectively.

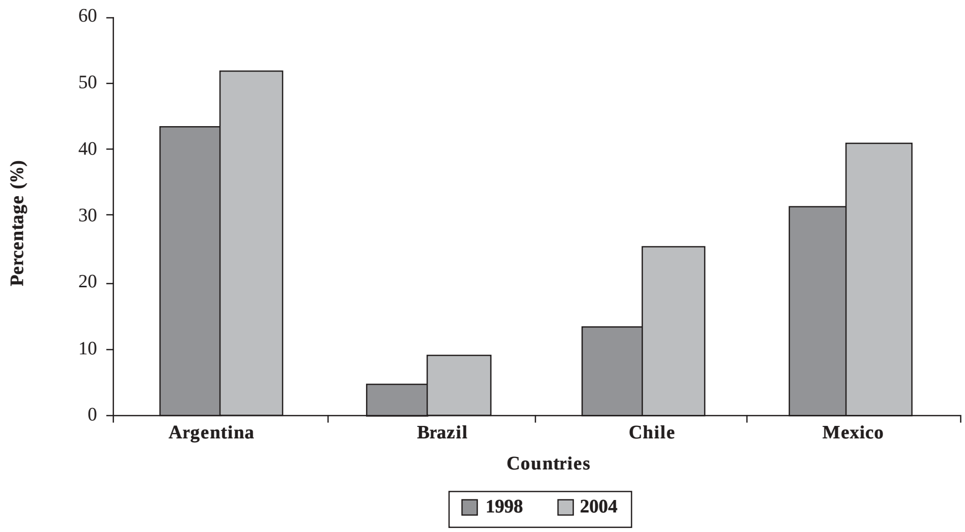
Of significance, is that even at this early stage of emerging gas-driven economies with limited gas infrastructure, **the share of natural gas in the LCR primary energy balance increased between 1998-2004 from 22 percent to 26 percent, while that of oil has declined from 47 percent to 44 percent**. The transition to gas is well under way already in the major energy producing and consuming countries in LCR, except in Central America and the Caribbean, excluding Trinidad and Tobago**.**

Figures 5 and 6 illustrate the extent to which gas penetrated at the expense of oil in the energy supply mix between 1998-2004 in Argentina, Brazil, Chile and Mexico. In the cases of Argentina and Mexico, despite the significant role of gas in energy supply in 1998, by 2004 its share had risen to above 50 percent and about 40 percent in these countries, respectively, while starting from small levels in 1998 in Brazil and Chile, its share doubled in both to 9 percent and 25 percent, respectively.

To satisfy the growing demand for oil and gas in the region, the amount of investment in oil and gas E&P as well as the development of natural gas T&D infrastructure appears inadequate to boost supply sufficiently to meet both LCR demand, and sustain an appropriate level of oil and gas exports. Intensification of these efforts in LCR is one of the key national policy initiatives required to enhance energy security.

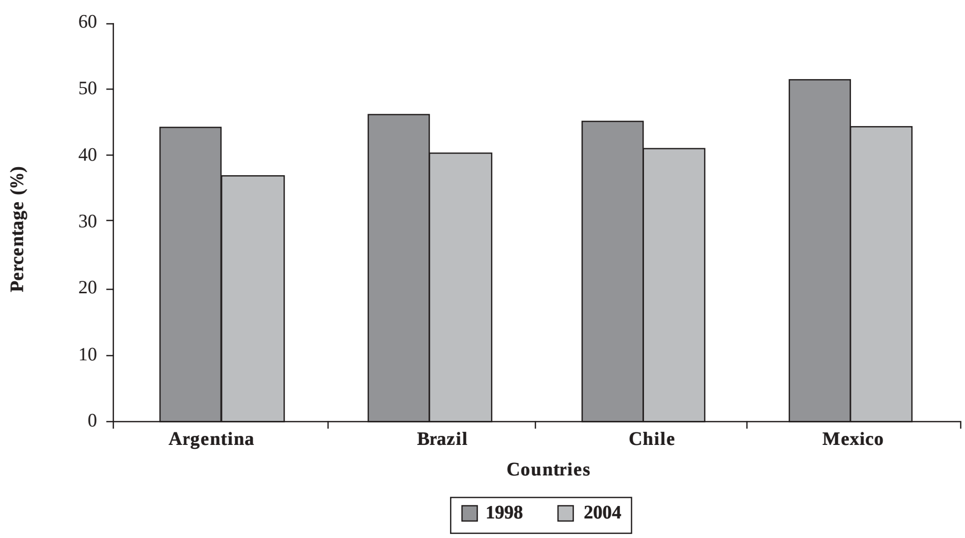
Oil and gas exploration efforts, however, are being constrained by environmental and local community issues. Exploration work in several onshore basins has been compromised by the demands of local communities and environmental Nongovernmental Organizations (NGOs) for better management of social and environmental impacts. Regulations have been enforced in practically all LCR countries for systematic Energy Information Administration (EIA) and community consultation processes. Moreover, communities are demanding greater compensation and participation in the rents. In several countries, entire regions are, de facto, closed to industry operations. While many of these initiatives address real concerns, the

Figure 5: Gas in the Energy Supply Mix of Argentina, Brazil, Mexico and Chile, 1998-2004



Source: Energy Information Administration (EIA), Department of Energy (DOE) Energy Supply Data from Web Pages for 1998 and 2004.

Figure 6: Oil in the Energy Supply Mix of Argentina, Brazil, Chile and Mexico, 1998-2004



Source: EIA, DOE Energy Supply Data from Web Pages for 1998 and 2004.

issue becomes one of seeking, where possible, a balance between oil and gas exploration requirements and environmental and social protection objectives.

Share of Fuels in the Energy Supply Mix in 2004

Among the NOEs, Trinidad and Tobago is almost a completely gas-driven economy with 94 percent of its energy supply derived from this source. In Argentina and Bolivia, gas contributes more than 50 percent of supply with hydro being the third largest supply

source after oil. While Venezuela and Mexico are the largest oil exporters in LCR, natural gas supplies about 40 percent of their energy needs and, in Colombia, 25 percent. Additionally, in Venezuela, hydro's share in the supply mix is about equal to that of oil (30 percent), with gas and hydro together contributing more than double that of oil. Ecuador is the only NOE where gas plays a relatively minor role in energy supply and the dependence on oil is greater than 50 percent.

In the case of the NOIs, there is a group of countries with very high dependence on imported oil in energy supply – Barbados (86 percent), the Dominican Republic (78 percent), Jamaica (86 percent), Panama (72 percent) and the smaller Caribbean islands. Though the share of oil in the Haitian supply mix is low at 26 percent, this reflects more the low level of economic development as indicated by the high dependence on wood fuels (69 percent). As shown in Figure 6, by 2004, in both Brazil and Chile, the share of oil in supply had been reduced to 40 percent. What is significant in both countries is the extent to which the diversification away from oil into other sources has reached. In Chile, natural gas, coal and hydro together contribute about 13 percent more than oil, while, in Brazil, natural gas, coal, hydro and products derived from sugarcane together exceed the share of oil by about 5 percent. In the Central American countries of Guatemala, Honduras and Nicaragua, the dependence on wood fuel remains high ranging from about 32-47 percent, which accounts for the somewhat lower contribution of oil to the supply mix (40-52 percent) and highlights the challenges in formulating national energy strategies in countries with large rural populations. The geothermal leaders in the region, Costa Rica and El Salvador, obtain 13 percent and 17 percent, respectively, of energy supply from this source and, in Costa Rica's case, the additional large share of hydro (24 percent) contributes further to reducing oil's share to 50 percent. Finally, though Peru produces about 60 percent of its oil requirements, its supply mix is well diversified with hydro, gas and coal contributing about 60 percent of oil's share to supply in 2004.

Macroeconomic and Fiscal Linkages of the Oil and Gas Sectors in Mexico

The hydrocarbon sector plays a major role in Mexico's economy and provides important contributions to the federal budget. However, there are clear indications that the present institutional arrangements and E&P models are not sustainable. Reforms of the institutional and fiscal structures that link Pemex to Hacienda, as well as measures to promote private sector participation in the industry, are necessary**.** This would enable the financial challenges facing the sector to be met, while mobilizing advanced technology. The challenge facing Mexico over the next five to 10 years is that failure to implement the above measures and attract investment and technology to the sector could lead to reductions in oil and gas production which, in turn, would result in declining oil exports; increased petroleum and gas imports; major impacts in Mexico's fiscal position, and an economic slowdown**.**

Despite a 120 percent increase in Pemex's oil and gas E&P investment between 1999-05, the proven reserve to production ratio has declined to 9.5 and 10.5 years for oil and

gas, respectively. Significant challenges lie ahead for the company to enable its integrated proven reserves replacement to begin to approach its own target of 77 percent by 2010, given that in 2005 it was 25 percent. **This is particularly relevant in Mexico as it is the only country in LCR where only the NOC is licensed to explore for and produce hydrocarbons.**

Currently, oil revenues contribute to about one-third of the federal budget, with this rising to about 40 percent in 2005 and 2006. This results in the budgets of both Pemex and the federal government being highly vulnerable to oil price shocks. In January 2006, a new tax regime for the oil and gas sectors was adopted to seek to ensure greater financial stability for Pemex. Prior to this reform, the fiscal regime for Pemex focussed on charging high royalties on gross production. Pemex, therefore, transfered at least 60.8 percent of its total sales to the Treasury. This stripped the company of resources for E&P, and the "midstream" refining sector, and resulted also in crushing debt. Indeed, Pemex's 2005 financial statement indicated that it had US$99.2 billion (bn) in total liabilities and US$96.7 bn in total assets. During that year, Pemex registered before tax earnings of US$51 bn, a 13 percent increase over 2004 due to higher oil prices. However, the company's net result after taxes and duties was a loss of US$3.8 bn.

The new tax regime brought a slight improvement to Pemex. During the first nine months of 2006, Pemex paid the equivalent of 56 percent of its total sales in taxes and duties compared with a 62.5 percent fiscal burden in 2005. However, the new fiscal regime has to come closer to international practice if it is truly to have the desired impacts in preserving and increasing oil tax revenues; give clear incentives to invest efficiently in new projects; and maximize economic yield of existing fields. Charging royalty rates of 78-87 percent damages Pemex's finances and does not provide the right incentives to maximize reserves. **Above all, it is not the only mechanism to maximize fiscal revenues. For example, Canada, Chile, Colombia and Norway register a government oil "take" of about 70 percent, while charging the industry with effective royalty rates of 8 percent, 7 percent, 27 percent and 0 percent, respectively.**

The urgency in completing the fiscal reform process, as outlined above, cannot be overemphasized since Pemex needs to invest US$18 bn annually for the next 10 years, compared to spending some US$10 bn annually in recent years. Raising this level of resources will be no mean feat. In 2005, the federal government's total investment was about US$33 bn, which was about 20 percent of the federal government's fiscal revenues for 2005. Of this, Pemex received about US$10 bn which was approximately similar to the amount invested in major social programs, for poverty alleviation, health, education and rural infrastructure. Indeed, in the absence of significant private sector participation in the investments required in oil and gas over the next decade, **any increase in the allocation for oil and gas investments will entail a choice about the extent to which oil rents could be used to finance high-priority social programs and other spending priorities at the federal level or to finance increased oil and gas production and refining. A path needs to be found to allow private investment in the sector to alleviate the burden on public finances.**

Cross-border Gas Trade

If natural gas is to maintain its rapid expansion in substituting for oil products in the LCR during the next 10 years and continue to play the role of the key "bridging" fuel to an era of less environmentally damaging fuels, high priority needs to be given to the development of cross-border gas transmission systems. However, achieving this while meeting the concerns of importers would require that the appropriate institutional mechanisms be put in place, especially for the major markets of the Southern Cone.

The most important regional intervention of the World Bank Group in the oil and gas sector during the last decade was its support for the Bolivia-Brazil gas pipeline project, which it financed through a loan and credit guarantee amounting to US$310 mn in 1997. At present, the World Bank is supporting the efforts of the five Southern Cone governments and those of Peru and Bolivia in studies to determine the technical and economic feasibility of a major 3,500 kilometer (km) expansion and re-enforcement of the gas infrastructure network linking the gas fields of the seven countries – this is the Southern Cone Gas Integration Project. The initial investment cost of the new pipelines to be added is estimated at US$4.2 bn, with the total investment estimated at US$6.8 bn over the project's lifetime. This project would be designed to transport, by 2015, about 3.8 billion cubic feet per day (bcfd) of gas into the major load centers in the Southern Cone.

A 220-km gas pipeline from eastern Colombia to the Maracaibo region of Venezuela, with a capacity of 500 mmcfd, is planned to be operational by mid-2007. The governments of Colombia and Venezuela have signed a four-year contract for the export of 140 mmcfd of Colombian gas to Venezuela from mid-2007 to mid-2011, presumably to meet a gas deficit in western Venezuela. There would be the possibility post-2012 for the gas flow to be reversed, if Venezuelan supply became available. This would provide the basis for gas to be delivered from Venezuela via Colombia and subsea Colombian / Panamanian pipeline to the southern zone of the isthmus.

Several studies to deliver gas into Central America have been undertaken to date. The earlier studies were sponsored by Comisión Económica para América Latina y el Caribe (CEPAL) and Organización Latinoamericana de Energía (OLADE), while the one currently being undertaken at the feasibility level is sponsored by CEPAL, Banco Interamericano de Desarrollo (BID) and Fondo Multilateral de Inversiones (FOMIN). The results of this study would be available in April 2007. A gas pipeline extending from southern Mexico across the isthmus to Panama would entail a distance of some 2,200 km.

There are fundamental issues regarding where the gas supply for Central America would come from. Supply from Colombia is constrained, though the possibility of future supply from Venezuela via Colombia could arise post-2012. However, the Venezuelan supply option does not appear to be under consideration in the ongoing feasibility study. The other supply option being examined, Mexico, is unclear since Pemex plans major increases in its own gas imports over the next decade, but based on LNG. It is most likely that gas would be introduced into the isthmus in an incremental manner beginning at both ends of the isthmus.

A much more modest gas pipeline project, the Eastern Caribbean Gas Pipeline (ECGP) is designed to transport up to 150 mmcfd of gas from Tobago to the islands of Barbados, St. Lucia, Martinique, Guadeloupe and Dominica. This is designed to substitute gas for petroleum products primarily for power. The investment cost is estimated at US$550 mn for the undersea pipeline over a distance of some 465 miles. The project, which is a private sector-led effort, has received approval of the Barbados government for the import of gas by pipeline, and is awaiting approval from France and the Departments of Martinique and Guadeloupe.

Given the recent setbacks to an early expansion of gas trade between Argentina and Chile, and Brazil and Bolivia, the first issue to be addressed is to restore trust in the sanctity of contracts between the affected parties and third parties contemplating importing cross-border gas. The experience in cross-border pipelines highlights the need for an "umbrella" agreement between the governments involved and, above all, large private sector participation to ensure the commercial character of the trade.

In addition, an agreement on an appropriate mechanism to resolve disputes is critical to provide momentum to further expand cross-border gas trade, particularly within the Southern Cone. Outstanding issues that need to be addressed include: (i) the priority assigned to the national market over and above contractual obligations for the export of gas; (ii) a "supranational" authority with powers for the resolution of disputes; and (iii) the roles of governments, State companies and private sector companies in the new dispensation. However, within the context of the negotiations between Petrobras and Bolivia, it was reported[1] that Bolivia had the intention to withdraw from the International Centre for Settlement of Investment Disputes (ICSID)(of the World Bank), the main international forum for dispute settlement on cross-border investments. This is likely to cast further doubt on the acceptability of a "supranational" dispute resolution mechanism referred to above. **It highlights further the susceptibility of any mechanisms put in place to resolve investment disputes to fundamental changes in the policies of governments.**

Refineries

State-owned domination of the "midstream" refinery sector has remained the norm in LCR, being an area of the oil sector that remains largely untouched by the reform of the 90s. There are some 73 refineries in 24 LCR countries. Most of these facilities were designed originally to serve protected national markets, except for the major export-oriented refineries in the Caribbean Basin – Aruba, Netherlands Antilles, Trinidad and Tobago, Venezuela and US Virgin Islands – which account for about 25 percent of crude oil distillation capacity in the region. The majority of the refineries have suffered from low investment; low margins and weak profitability; surpluses of residual fuel oil arising from gas substitution in power generation and industry; new environmental specifications for products; and so on, and so forth.

[1] *"Bolivia and Brazil Resolve Oil Dispute,"* Financial Times, May 11, 2007.

At this juncture, the refinery sector requires major investment and reform if this vital sector is to develop into a competitive and efficient industry. To achieve this would call for significant changes in current policies, among others, pricing policy at the ex-refinery level and allowing public / private joint ventures between the SOEs and private companies. A major regional study on the refining sector funded by the Energy Sector Management Assistance Program (ESMAP) and Canadian International Development Agency (CIDA) and issued in 2002, estimated LCR refinery investment requirements for the period 1998-2015 at US$34.2 bn, based on a 4 percent annual growth in product demand throughout this period. This investment would be of about US$18 bn (in 2002 US$) over the period 2005-15, assuming a lower annual product growth of 3 percent. The challenge ahead is clear, being particularly difficult in those oil- and gas-producing countries (Chile, Colombia, Ecuador, Mexico, Trinidad and Tobago and Venezuela) where SOEs possess a "midstream" monopoly and product prices do not reflect economic costs**.**

The recently announced Mesoamerican Energy Integration Program (MEIP) launched by Mexico includes, as one of its components, the construction of a 360,000 bbl/day refinery in either Guatemala or Panama at a cost of US$6.5 bn to be funded mainly by the private sector. The intent is that crude oil will be supplied primarily by Mexico and will supply products to the participating States with some sales also envisaged to the USA, which is experiencing a shortage of refinery capacity. Clearly, if this project does materialize, then a major rationalization of refining capacity in Central America would occur with the expected closure of at least some 66,000 bbls / day in capacity in the remaining three countries with refineries.

The Nonoil Producers of LCR – Central America and the Caribbean – Concessional Oil Import Financing Schemes

One of the greatest challenges faced at the subregional level concerns the nonoil producers in Central America and the Caribbean. The share of oil in the energy supply mix in many of these countries is very high and the infrastructure is not in place to deliver natural gas from neighboring countries. In these countries, concessional financing schemes for oil imports have been launched recently by Venezuela and Mexico.

Concessional oil import financing under Venezuela's PetroCaribe Accord (PCA) has become available to the Caribbean countries. PCA's Memorandum of Understanding (MoU) was signed between Venezuela and 10 Caricom member States, Cuba and the Dominican Republic, in June 2005. One of the distinguishing features of similar arrangements in the past between Venezuela, Mexico and Trinidad and Tobago was that there was an agreed allocation of responsibilities between the suppliers. This is not the case with the PCA. A further critical difference between these earlier oil facilities and the PCA is that the latter seeks explicitly to have a "direct trade relationship (with the importing countries' State agencies) without intermediaries in the supply process."

Though the PCA mechanism does provide some financial relief, there are important macroeconomic and supply security concerns. In particular, the rapid increase in external debts of some of the most heavily indebted countries in the world, and the potential deterioration in supply security due to the sourcing and transport of the petroleum being undertaken by only one party.

Subsequent to the launching of the PCA, Mexico announced the MEIP initiative which includes eight other countries – Guatemala, Belize, Honduras, El Salvador, Nicaragua, Panama, Costa Rica and the Dominican Republic. In addition to the planned 360,000 bbls/ day refinery to be built in Central America mentioned earlier, Mexico has agreed to supply petroleum products to the MEIP countries on terms similar to the PCA, but without the statist trade objectives of the PCA of "cutting out the middle men."

Energy Security, Diversification Strategies and Climate Change

The diversification away from oil into natural gas is already well under way throughout the region, except in those countries without access to gas. While this trend fits in well with the climate change agenda, as demand for gas continues to rise one can expect this to affect its price as gas producers seek to extract a higher share of the rent. This was seen in the recent negotiations between Bolivia and Brazil, and in the negotiations between Bolivia and Argentina, in which a price of US$5 / million British thermal units (MMBTUs) was reportedly agreed to.

The key to maintaining the momentum in gas use and substitution is to enhance the regional cross-border trade in gas, especially for countries that can access pipeline gas. While the immediate task in the Southern Cone Gas Integration project is that of rebuilding confidence and trust in such trade, it is equally important that the two major gas suppliers, Bolivia and Peru, recognize that the cost to them of nonintegration is roughly double the foregone benefits to the importers of gas. This is relevant particularly for Bolivia since its only other option is that of LNG export, which raises the issue of its access to the Pacific.

Penetration of natural gas into the last bastion of oil dominance, the transport sector, is also beginning to emerge. In Argentina, Compressed Natural Gas (CNG) use in transport already accounts for about 7 percent of the natural gas demand, while in Brazil and Colombia, it accounts for about 3-4 percent. This end use of gas in urban transport has important positive impacts on the environment, especially for the high-altitude cities and concurrently attenuating climate change impacts, while decoupling the politically sensitive issue of public transport costs from the prices of diesel oil and gasoline and international oil prices.

As part of their gas supply diversification strategies, Chile, Brazil and Mexico are planning to import LNG. In these large gas markets, LNG can play a useful role in reducing dependence on a single imported gas source. However, in the smaller markets of Central America and the larger northern Caribbean islands, LNG import strategies need to be assessed very carefully. This is required since LNG delivered anywhere in the Caribbean Basin or the Gulf of Mexico would be indexed, in all probability, to Henry Hub gas prices. In the case of these small markets, LNG's "commoditized" high and volatile price can expose these markets to very high risks, raising issues of competitiveness of this fuel for base load power generation, especially when compared to imported low-sulfur coal.

The Path Forward and Role of the World Bank Group

The World Bank Group has lost its balance in the scale and scope of its interventions in the overall energy sector in LCR over the past several years. Given the scale of the LCR's energy resources; the critical nature of the region's energy sector challenges; and their associated macroeconomic, social and political linkages, **it is vital that the rebalancing of the World Bank Group's investment, advisory and sector work programs over the next few years be addressed urgently, if the institution is to be seen as a credible energy partner.** Recent experiences in the region (Brazil, Chile, Colombia and the Dominican Republic) have shown that energy shortages have immense political and economic costs. In this context, energy policy and decision makers, all of whom seek renewed mandates from the public every five years, naturally assign some of the highest priorities to those strategies that can have significant and beneficial impact within, at most, the medium term.

What this implies for the World Bank Group is that its LCR energy sector strategy needs to be anchored around a "double-pronged" strategy, each prong of which would be of equal high priority, but requiring different levels of financial commitments and interventions. ***The first prong would focus on financing in the traditional electric power and oil/gas sectors.*** In the electric power sector, the target would be, among others, major power generation, especially hydro projects and power transmission projects. Additionally, the reform of the electricity sector is incomplete in many countries and requires further World Bank support. In the natural gas sector, cross-border gas interconnections would be a focal point, along with support for deepening regulatory practices. Through such financing, the World Bank Group would be instrumental in fostering effective private / public partnerships in the above areas. ***The second prong would target support for programs and projects addressing EE; access to affordable energy services for the poor; the development of "clean" energy and measures to address climate change issues in LCR.***

The World Bank´s role in addressing the climate change agenda would have to rely on its capacity to deal effectively with the doubled-pronged strategy. The World Bank's support for the financing of generation and transmission, and particularly large hydroelectric projects, and cross-border gas interconnections, can make a major contribution to the development of clean energy in the region that cannot be achieved with the existing mechanisms (carbon finance and Global Environment Facility – GEF), and will provide the leverage to allow the World Bank to play a substantive role in policy making and energy mix choices.

Electricity

LCR had a marginal share of the total public sector energy lending program of the World Bank Group during the past 10 years. While Europe and Central Asia (ECA) and East Asia received about 27 percent each, LCR's share was only 8 percent. This can be explained by the fact that other regions were slow in implementing market-oriented reforms and the World Bank continued financing large infrastructure investment projects while, in LCR, the World Bank moved away from power generation and transmission in favor of large development policy loans to support sector reform, and small loans to support carbon finance, rural energy, RE and EE programs.

The World Bank needs to shift the composition of its energy portfolio in LCR to help the countries face new challenges. Although it is necessary to strengthen the existing carbon finance and GEF programs to support the development of RE, EE and rural energy, financing of large investment projects should be a high priority, mainly power generation and regional energy trade:

- **Financing of power generation projects is required**. The development of medium and large hydroelectric, coal-fired and geothermal projects requires the World Bank's support to PPPs; investment loans to the public partner, and guarantees and other financial instruments to reduce project and market risks and lower the cost of financing to the private partner; and
- **Need to support regional energy projects**. There is a great potential in increasing energy trade in the region, but many countries are reluctant to depend on firm energy supply from cross-border trade. To diversify energy supply and strengthen energy trade in Central America, the World Bank can support the preparation of a feasibility study for the development of a regional generation project and provide financing for new electricity interconnections between Colombia and Central America. Financing of a new interconnection between Uruguay and Brazil is also a good opportunity to rebuild confidence in electricity trade.

Improving the regulatory framework and the financial viability of the sector are essential to avoid the risk of backstopping financing of projects that may become a fiscal burden for governments. Regardless of the ownership or market arrangements used, the power sector will not be financially viable if electricity tariffs lag behind costs and if there is lack of political support to implement programs to reduce electricity losses and improve collections. World Bank support to PPPs with credit enhancement instruments for the implementation of generation projects is an option in countries where the government supports a credible program to maintain or improve the financial viability of the sector.

The World Bank should step up its support to the development of RE, EE and rural energy in the region. In several countries, energy policies and plans call for a substantial increase in the market share of RE (wind power, biomass, small hydro, geothermal and biofuels) and the implementation of EE programs to enhance energy security and address climate change concerns. Countries with low electricity coverage need to develop ambitious rural energy programs to improve access to electricity services for the poor.

World Bank support is needed to improve corporate governance and consolidate sector reforms. Pushing the privatization agenda is not a short-term option for political and practical reasons. Improving the performance of SOEs without restructuring is not an option. The World Bank should support corporatization and participation of domestic shareholders or management contracts in SOEs in countries willing to engage. The World Bank should continue supporting the development of strong regulatory institutions and second generation market reforms in the region.

Oil and Gas

Stepping up to policy and investment challenges: the main challenge facing the World Bank Group in the oil and gas sector in LCR has been the very limited level of its interventions from the sector work and financing perspectives over the past decade. This has resulted in the institution possessing a far weaker knowledge base than that in the electric power. Given that the oil and gas sectors are critical both to the region's ability to ensure its security of these fuel supplies from either a net importer or exporter perspective and from a macroeconomic standpoint, it is critical that the World Bank Group re-engages in these sectors.

In tailoring its interventions in oil and gas, the following are areas in which the World Bank Group has an important role to play:

- **Regional cross-border gas projects – in particular, the Southern Cone Gas Integration project; the introduction of gas into Central America; and the ECGP project**. A key requirement would be an agreed mechanism, between all of the parties and the World Bank Group, for the resolution of disputes. Its support would address climate change, diversification away from oil, deepen energy and regional integration efforts through its advice on institutional structures to mitigate cross-border conflicts, and its investment and guarantee instruments. Additionally, the World Bank can play the role of an honest broker in the preparation of inter-governmental agreements that are key instruments underpinning cross-border projects, based on its experience in the Bolivia / Brazil gas pipeline as well as those outside the region, such as Mozambique / South Africa, Nigeria / Benin, and Togo / Ghana;
- **Development of gas regulatory practices.** Supporting the further development of gas regulatory practices in targeted countries to enhance the expansion of in-country gas T&D networks and, eventually, the evolution of a competitive gas market;
- **Financing refinery modernization and upgrading.** This is an area in which the International Finance Corporation (IFC) (of the World Bank Group) would be well

positioned to support those projects which are structured as joint ventures between State and private companies. This implies that ex-refinery prices would reflect those at the international level and move in tandem with them;

- **Modernize and corporatize NOCs in countries willing to engage.** This intervention would entail two separate components, through appropriate instruments. First, separate the institutional, contractual and regulatory roles of the State from those of the NOC, which should focus on investment, production and commercial responsibilities. This would be followed by the commercialization and corporatization of the NOC, and after a period of satisfactory performance, offer shares on the local market, with government retaining a golden share. Second, the removal of the “broad band” subsidies on petroleum products and gas with these being replaced by well-targeted cash transfers to lower income groups, along the lines of what was successfully done in Indonesia; and

- **An intensified sector work program in the oil and gas sector** which should be designed to support, among others, the regional projects the World Bank decides to support; those issues which are country-specific, such as gas regulatory practices, petroleum product and gas pricing policies, and continued SOE reform.

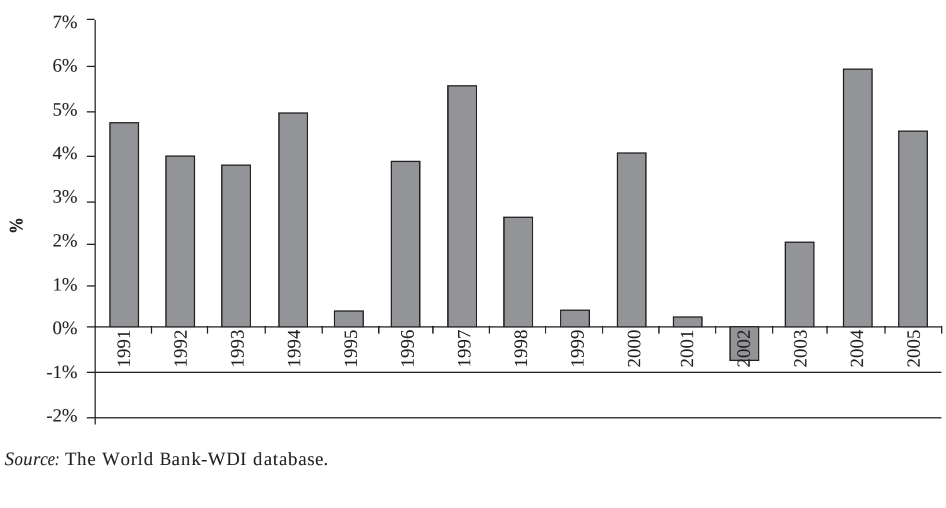
1. Assessment of Energy Market Reform

External shocks had a major impact on energy sector reform in the region, thus severely testing its performance. During the past 15 years, when most reform of the energy sector took place in the Latin America and the Caribbean Region (LCR), the energy sector was exposed to external economic shocks in many of the large countries (Brazil, Argentina and Colombia), which are reflected in a negative or nil growth of Gross Domestic Product (GDP) during the period 1999-2002, and a 100 percent increase in the price of crude oil during the past two years (Figure 1.1). Furthermore, severe droughts affected countries that depend on hydro generation: Colombia and Chile in 1997-99 and Brazil in 2001. These external shocks have been a severe test of energy sector reform, as high oil prices had a major impact on generation costs in thermal-based generation systems, droughts have put the security of energy supply in hydro-based systems at risk, and currency crashes had a major impact on the finances of private utilities.

Evolution of Electricity Demand and Supply in the Region

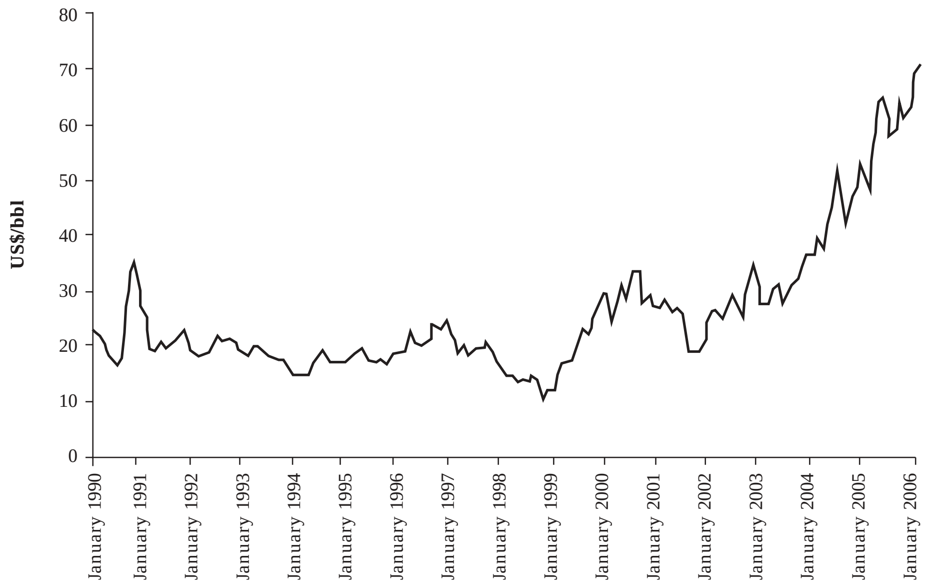
The annual rate of growth of electricity demand in the region for the past 15 years (1990-2004) was about 4.5 percent, with substantial differences between subregions and between periods. While Central America and the Caribbean maintained high annual rates

Figure 1.1A: LCR – GDP Annual Rate of Growth (constant US$2,000)



Source: The World Bank-WDI database.

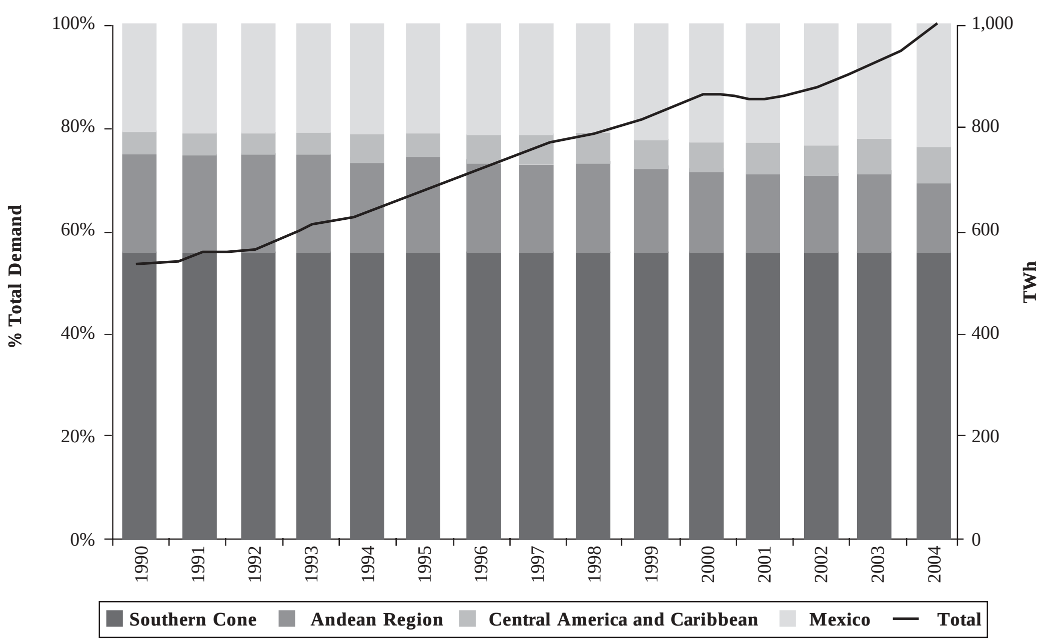
Figure 1.1B: WTI Monthly Price



Source: Prepared by authors based on EIA data in Web page.

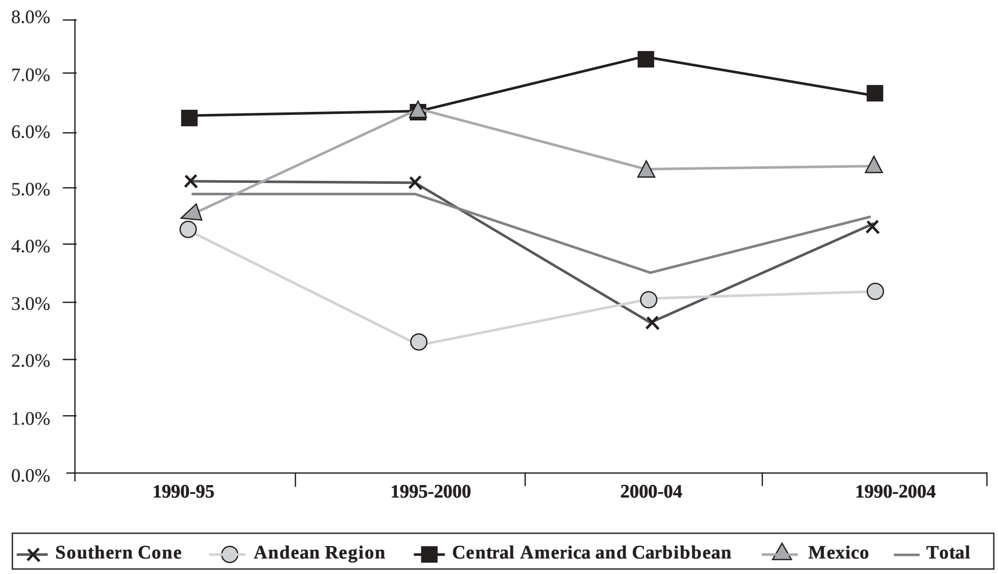
of growth of about 6.5 percent on an average, and Mexico of about 5.5 percent, the Andean countries grew at a lower annual rate of 3.2 percent. While the region grew at about 5 percent per year in the 90s, the annual rate of growth dropped to about 3.6 percent from 2000-04, which reflects the impact of the energy and economic crisis in the Southern Cone. In 2004, the Southern Cone represented about 55 percent of electricity demand in the region: Mexico about 22 percent, the Andean countries about 16 percent and Central America and the Caribbean about 7 percent (Figure 1.2).

Figure 1.2A: Total Electricity Demand



Source: The World Bank-WDI database.

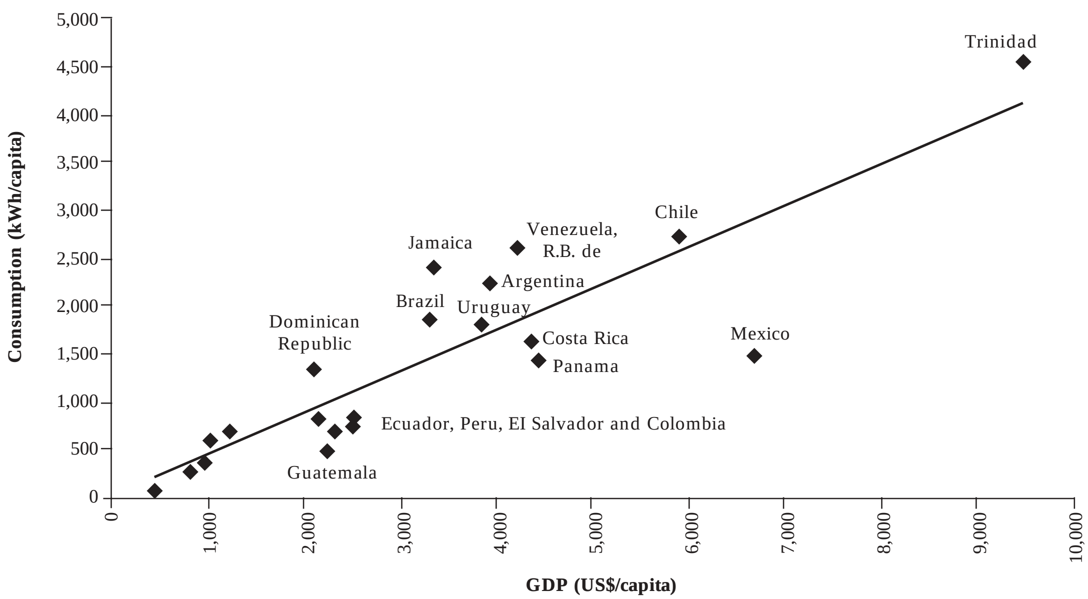
Figure 1.2B: Annual Rate of Growth of Electricity Demand



Source: The World Bank-WDI database.

Per capita electricity consumption is uneven between countries in the region, reflecting differences in income per capita, Energy Efficiency (EE) and participation of electricity intensive industries. The upper middle income countries, with an average Gross National Income (GNI) per capita of about US$4,800, have a per capita consumption between 1,500 and 2,750 kilo watt (s) per hour (kWh) / year. The lower middle-income countries, with an average GNI per capita of about US$ 2,400, have a per capita consumption between 500 and 1,400 kWh / year. The low-income countries, with an average GNI per capita of about US$880, have a per capita consumption between 300 and 700 kWh / year (Figure 1.3).

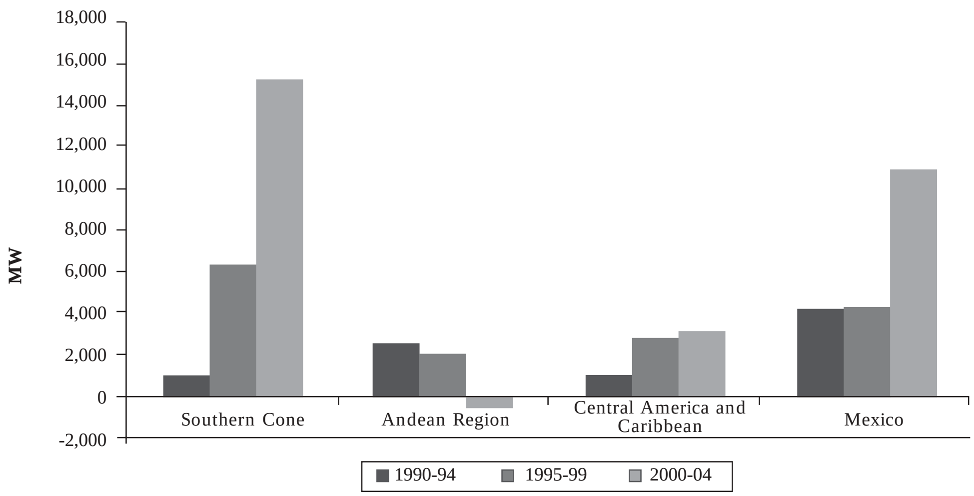
Figure 1.3: Electricity Consumption Versus GDP (per capita) in 2004



Source: The World Bank-WDI database.

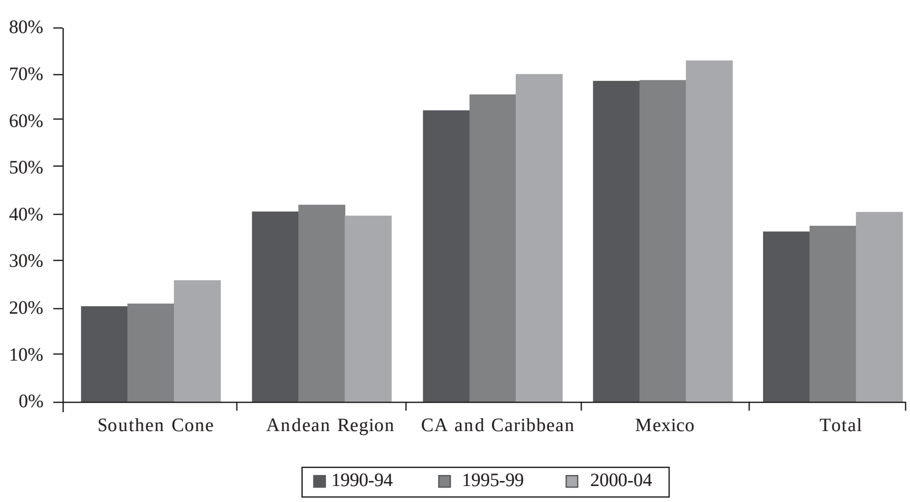
Thermal generation plants have increased its participation in the generation capacity mix during the past 15 years. In Mexico, Central America and the Caribbean, the regions which are dependent on thermal generation, its participation increased by about 5 percentage points during the last five years to about 70 percent. In the Andean countries, thermal generation capacity remained at about 40 percent of the total installed capacity. In the Southern Cone, a subregion dependent on hydro generation ((due to the high relative weight of Brazilian hydro generation), thermal generation increased its participation by about 5 percentage points to 25 percent. The expansion of thermal generation capacity is more striking. In all subregions, except the Andean countries, the net thermal capacity that has been added has increased during the past three quinquenniums. During the last 15 years, the region has installed about 52,000 mega watt(s) (MW) in conventional thermal plants, of which 29,000 MW was installed during the last quinquennium (Figure 1.4).

Figure 1.4A: Thermal Generation Capacity Expansion (in five-year periods)



Source: Prepared by authors based on EIA´s data in Web page (2007).

Figure 1.4B: Thermal Generation Capacity Expansion (% of total subregional capacity)

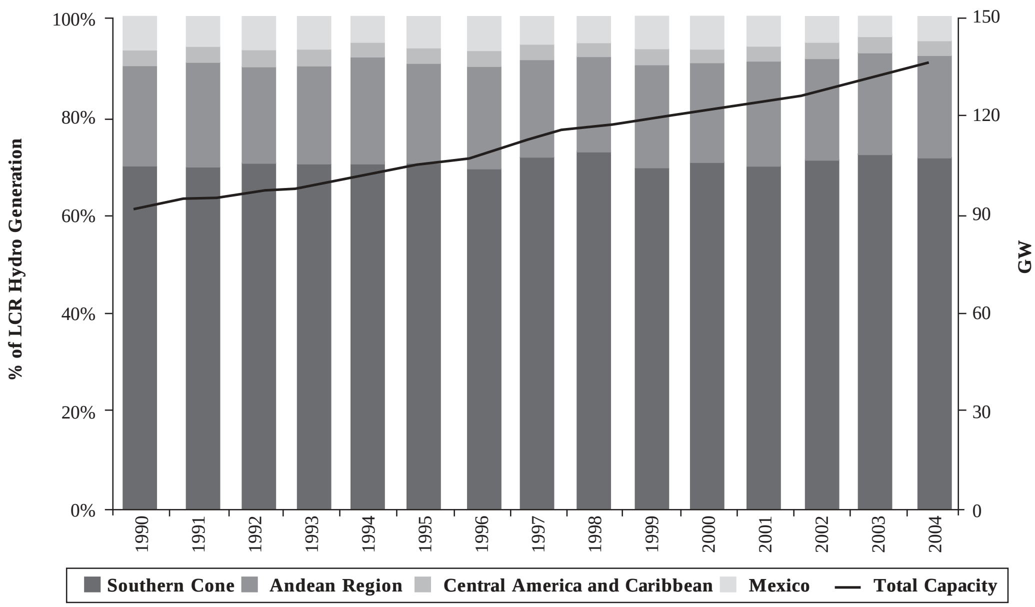


Source: Prepared by authors based on EIA´s data in Web page (2007).

The region has continued to expand its hydroelectric generation capacity steadily to use its large hydroelectric potential, although at a lower rate than in the 80s. During the past 15 years, a hydroelectric capacity of about 40,000 MW has been added, with Brazil contributing about 60 percent. More than 90 percent of the total hydroelectric generation in the region is concentrated in the hydro-dependent countries in the Southern Cone and the Andean subregions (Figure 1.5).

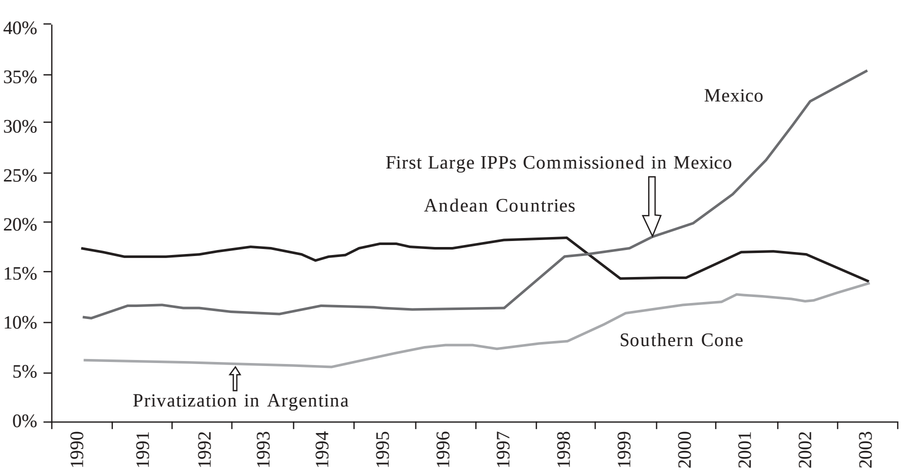
During the last 15 years, electricity generation in the region has become more dependent on fossil fuels, mainly natural gas in Mexico and the Southern Cone, and residual fuel oil in Central America and the Caribbean (Figure 1.6). This transformation of energy sources reflects the fact that, in countries with access to natural gas, private investors preferred the Combined Cycle Gas

Figure 1.5: Hydroelectric Generation



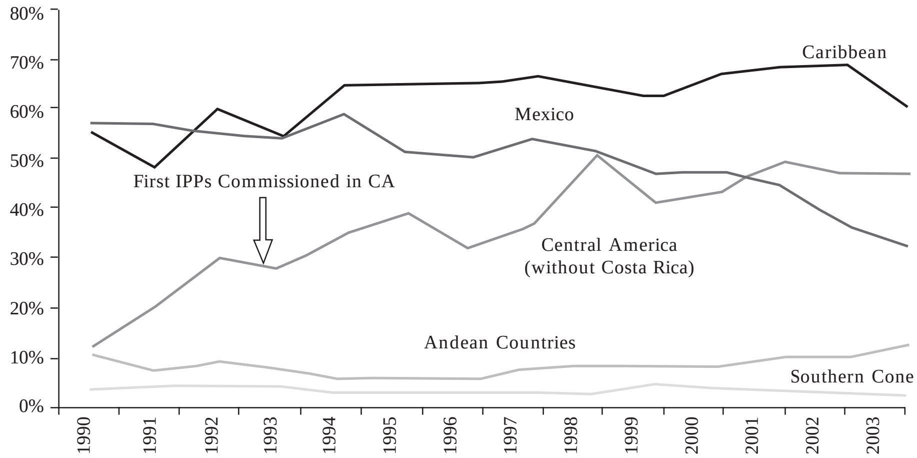
Source: Prepared by authors based on EIA´s data in Web page (2007).

Figure 1.6A: LCR – Natural Gas Generation (% of total generation)



Source: The World Bank-WDI database.

Figure 1.6B: LCR – Oil Generation (% of total generation)



Source: The World Bank-WDI database.

Turbine (CCGT) technology, characterized by low levelized generation costs, high thermal efficiency, relatively low capital costs, short construction periods and low environmental impact. In Central America and the Caribbean, oil-based thermal generation has increased its participation from 12 percent to about 50 percent (excluding Costa Rica) mainly due to the expansion of the installed capacity in Medium-speed Diesels (MSDs) burning residual oil, an option chosen by Independent Power Producers (IPPs) due to its high efficiency, competitive generation costs, relatively low capital cost and short construction periods.

Electricity Sector Reform

Electricity sector reforms in most countries in LCR in the 90s were motivated by poor performance of the public model where the State was policy maker, regulator, investor and monopoly provider of the electricity supply service. Lack of incentives for efficiency in the operation and expansion of the sector, and the politicization of policy decisions and management of sector utilities resulted in high electricity losses and Administration, Operation and Maintenance (AOM) costs, investments in generation that did not respond to least-cost principles, relatively low electricity coverage, electricity tariffs that did not reflect economic costs, difficulties in mobilizing the financial resources required for the expansion of the power system, poor reliability of service and recurrent financial losses of State-owned Enterprises (SOEs) that were finally reflected on unsustainable fiscal deficits.

The reform of the electricity sector in LCR, which was part of a broader reform of the public sector, based on the introduction of market principles, aimed to solve the main problems that besieged the public sector model: improve the quality, reliability and efficiency of electricity services, improve the government's fiscal position and increase affordable access to energy services for the poor. To achieve these objectives, a market-oriented reform promoted: (i) the separation of roles of policy making, regulation and service provider – limiting the role of the State to policy making and regulation, and relying on the private sector as the main investor and provider of electricity service; and (ii) the introduction of competition, wherever possible, and of economic regulation in the activities that are natural monopolies, as main instruments to improve economic efficiency. This market model would improve the government's fiscal position and ensure the financial sustainability of the sector by promoting the participation of private investment and the establishment of competitive prices for generation and cost-covering tariffs for Transmission and Distribution (T&D). It would be sustainable from a social and political point of view by improving access to energy services for the poor, based on a scheme of efficient subsidies.

All countries in LCR, with the exception of Paraguay, Suriname and the small island States in the Caribbean, introduced or attempted to introduce reform along these lines. The Tables in the Annex summarize the characteristics of the power reform in most countries in the region. The differences are in the extent of competition and private participation. Three basic market models were used in the region: (i) a vertically integrated monopoly and IPPs that sell their production or excess generation to the monopoly at avoided cost or to a price determined by competitive bidding; (ii) a single buyer of electricity that purchases the required energy under long-term contracts following competitive bidding procedures; and (iii) a competitive wholesale power market where generators, distributors, marketers and large consumers trade electricity in spot transactions and long-term contracts. At the lower end of competition are countries like Mexico and Costa Rica that decided to maintain a vertically integrated monopoly or countries like República Bolivariana de Venezuela (referred to hereafter as Venezuela in this report) and Uruguay that approved a new law establishing a wholesale market but for different reasons, have not implemented the law. The single buyer scheme is working in some of the large island states of the Caribbean Community (Caricom), Honduras and Guyana, which represent a marginal percentage of electricity demand in LCR. Most countries in Central and South America, representing about 65 percent of electricity demand in LCR, have implemented a wholesale power market (Table 1.1).

The level of private participation is not directly related to the scope for competition in all cases. For example, the smaller island States in the Caribbean have high private participation with very limited competition. On the other extreme, Ecuador adopted a competitive wholesale power market but failed to attract private participation. However, in most cases, private participation increases as competition increases. At lower levels of competition, except for Jamaica, private participation is limited to generation in IPPs. At a high level of competition, the private sector has a substantial participation, mostly in distribution and generation.

The participation of the private sector in the provision of electricity services in the region is not a new event. In 1950, private utilities and self generators were responsible for about 90 percent of the electricity generated in the region. However, most countries in the region nationalized their private electric utilities in the 50s and 60s, and by 1975 government utilities accounted for about 78 percent of the total generation. The rise and fall of foreign private investment is sometimes explained by the concept of "obsolescing bargain," according to which private participation is promoted when it can offer superior technology, management and access to capital, but the combination of private monopoly and foreign ownership in

Table 1.1: Power Sector Reform in LCR

Competition

% Demand	*1%*	*33%*	*47%*	*18%*	
Unbundling, Wholesale Power Market, Large Consumers		Ecuador	Brazil, Colombia, Dominican Republic, El Salvador, Guatemala, Nicaragua	Argentina, Bolivia, Chile, Panama, Peru	65%
Single Buyer & IPPs		Guyana	Trinidad and Tobago, Honduras	Jamaica	2%
Vertically Integrated Monopoly and IPPs	Uruguay	Costa Rica, Mexico	Suriname		24%
No Competition	Paraguay	Venezuela, R.B. de		Most Island States	9%
	SOE	Low	Medium	High	% Demand
		Private Participation			

Source: Authors´ calculations based on 2005 data.

the provision of an essential service with politically sensitive prices creates pressures for nationalization (Gómez-Ibáñez, 1999).

Unbundling does not guarantee effective competition. Effective competition in the wholesale market can be assessed better by the extent of horizontal unbundling (number of generators and Distribution Companies – Discoms – participating in the market) and by the number and market share of large consumers that have the option to select supplier and negotiate the conditions and prices of energy supply. Table 1.2 shows the countries classified in two categories: high and low degree of competition. Most of the countries with high competition have implemented substantial horizontal unbundling, have reduced the threshold for large consumers below 500 kilo watt(s) (kW), and have a liberalized market with a market share above 21 percent. In the smaller markets, which have also introduced retail competition for large consumers, competition in the market is not effective because the industrial market is small.

The important conclusion is that most countries in LCR, which represent more than 60 percent of the demand in the region, progressed to the most advanced stages of competition and privatization in the 90s, much more than other regions of the World Bank where competition in most countries was limited to the single buyer model (Table 1.3). Therefore, there is a wealth of experience that can be used to assess the progress made in achieving the objectives or main drivers of the reform, namely: improve the quality, reliability and efficiency of electricity services; and improve the government's fiscal position and increase affordable access to energy services for the poor. Also, to analyze the main difficulties that threatened the sustainability of the reform, identify the main causes and draw some important lessons for the future.

Table 1.2: LCR – Wholesale Markets Extent of Unbundling and Retail Competition

		Gencos	*Self-generators and IPPs*	*Transcos*	*Discoms*	*Marketers*	*Large Consumers*	
							Threshold	*No. (market share)*
High	Argentina	41		57	62	46	5MW, Reduced to 30 kW	1,496 (21% of demand)
	Brazil	25	89	54	43	42	10 MW, Reduced to 500 kW	577 (21% demand)
	Chile	12	6	4	31	0	2 MW, Reduced to 500 kW	30% demand
	Colombia	66		11	32	67	2 MW, Reduced to 100 kW	4,206 (31% demand)
	El Salvador	4	10	1	5 (two groups)	5	Full Retail Competition	5 (10% demand)
	Guatemala	10	12	1	3+13 (small municipal)	7	100 kW	32% demand
	Peru	18		6	33	0	1 MW	46% demand
Low	Bolivia	8		2	6	0	1 MW	2
	Costa Rica	1	Four Small Cooperatives and Municipalities, 30 Small Renewable IPPs	1	1+6 Small Municipal and Cooperatives	0	No	0
	Dominican Republic	11	2	1	3	0	2 MW Reduced to 200 kW	
	Ecuador	13	16	1	20	0	1 MW	11% of demand
	Honduras	1	22	1	1	0	1 MW	1 (2%)
	Mexico	1	403 Power Stations (362 self-generators, 18 IPP, 36 cogen)	1	1	0	No	0
	Nicaragua	9	1	1	1	0	2 MW	9 (8% demand)
	Panama	8	10	1	3	0	100 kW	5 (2% demand)
	Uruguay	2	1	1	1	0	250 kW	0
	Venezuela, R.B. de		7 Vertically Integrated Monopolies, 2 D, 4 G			0	No	0

Source: Authors´ calculations based on 2005 data.

Table 1.3: Power Market Structures in Developing Countries by Region

Regions	*Number of Countries*	*Vertically Integrated Monopolies*	*Vertically Integrated Monopolies + IPPs*	*Discoms, Gencos, IPPs, With or w/o Single Buyer*	*Power Market, Gencos, Discoms, Large Users and Transcos*	
			Number		*Number*	*%*
Africa	49	39	8	2	0	0%
EAP	17	10	6	1	0	0%
ECA	28	7	2	15	4	14%
LCR	32	11	8	1	12	38%
MENA	13	6	5	2	0	0%
SAR	11	3	7	1	0	0%

Source: (Besant-Jones, 2006). Data for LCR revised by authors.

The assessment of reform includes: (i) an analysis of the impact on the main drivers of the reform; and (ii) a review of the main lessons learnt from the reform process.

Impact on Main Drivers of Reform

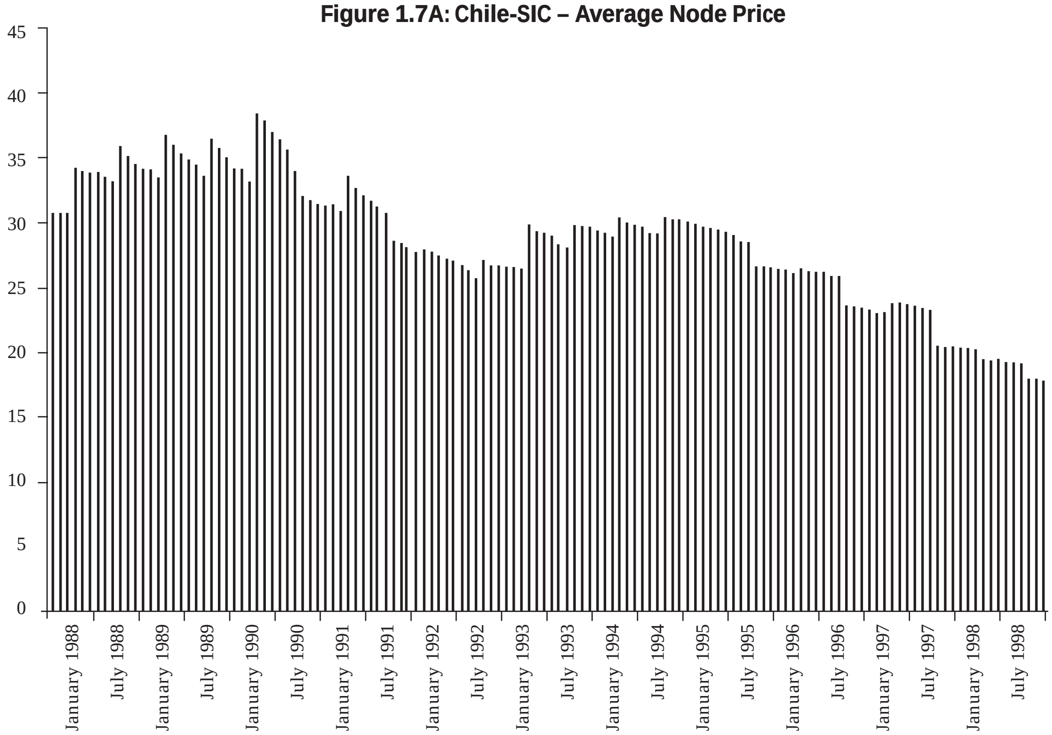
EFFICIENCY AND QUALITY OF ELECTRICITY SERVICE

Power sector reforms introduced incentives to improve efficiency and quality of service in generation. At the generation level, a market-oriented reform, based on competition and private participation, presumably introduced incentives to reduce generation costs by displacing inefficient thermal plants with new efficient technologies, improving the availability and efficiency of existing thermal generation, and implementing better fuel supply agreements, optimal dispatch of generation units, and least-cost expansion. IPPs had the incentives under Power Purchase Agreements (PPAs) to reduce construction costs, operate efficiently and maintain high reliability. As discussed above, during the past 15 years, the region has become more dependent on thermal generation, taking advantage of relatively low oil prices in the 90s, the availability of natural gas in some countries and the development of high efficiency CCGTs and medium- and low-speed diesel plants that could burn cheaper residual oil. These new technologies have relatively low capital costs, short construction periods and the flexibility of modular capacity sizes, characteristics which help reduce market risks and are very attractive to private investors operating in the uncharted waters of the reformed sectors.

Improvements in productive efficiency in generation resulted in lower wholesale prices. Although it is difficult to isolate the impact of external factors such as hydrology, fuel prices and depressed demand on wholesale prices, the price reductions of about 40 percent in real terms in the wholesale markets during the first 10 years of the reform in Chile and Argentina are examples of the benefits of competition and privatization Figure 1.7). Although noncontrollable factors influence the results, it is clear that the combination of competition and private participation helped to develop lower cost gas-fired generation, improve thermal efficiency and availability and reduce generation costs. In Argentina, after reform was implemented, availability of thermal plants increased from 48 to 71 percent, average heat rate for thermal units decreased by 30 percent, generation capacity increased to 7.9 percent per year based mainly on new gas-fired high-efficiency thermal plants, and the number of generators competing in the market increased from 10 to 41.

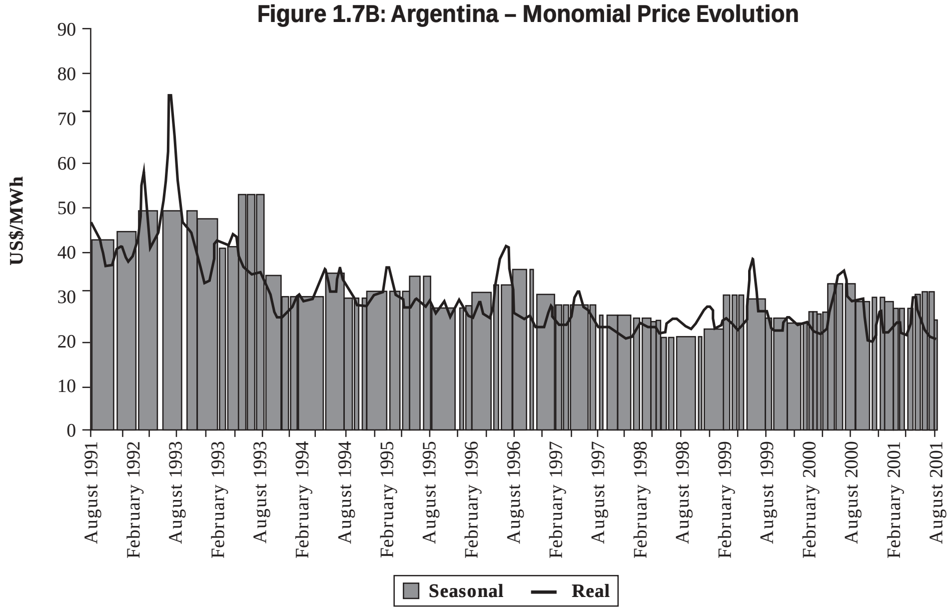
Thermal efficiency also improved in countries like the Dominican Republic and Honduras, with troubled electricity reforms. In the Dominican Republic, from 2001 to 2003, the combination of investments in the rehabilitation of existing steam plants, and expansion in new, efficient CCGT and diesel plants, reduced by almost 50 percent the variable generation costs in the supply curve, calculated at constant fuel prices. In Honduras, the equivalent heat rate of thermal plants under PPA contracts dropped by about 20 percent in six years due to improved bidding procedures to contract new energy with private IPPs and the addition of high-efficiency diesel engines burning residual oil (Figure 1.8).

Figure 1.7A: Chile-SIC – Average Node Price



Source: Sitio Oficial del Centro de Despacho Económico de Carga del-Sistema Interconectado Central (CDEC-SIC), Comisión Nacional de Energía (CNE).

Figure 1.7B: Argentina – Monomial Price Evolution



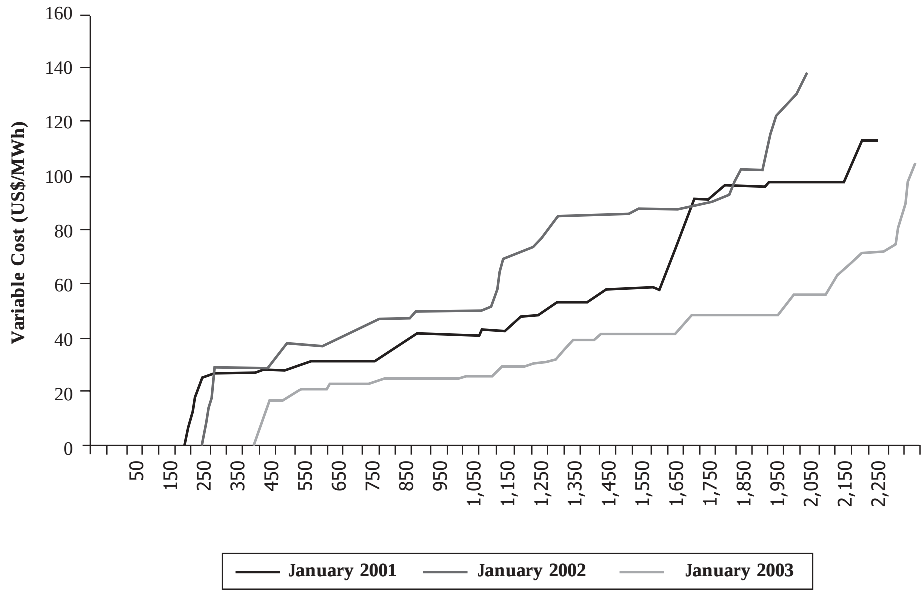
Source: Annual reports of Compañía Administradora del Mercado Mayorista Eléctrico S.A. (CAMMESA).

Table 1.4: Efficiency Improvements -- Generation

		Pre-privatization 1992	*Post-privatization 2000*	*% change*
Argentina				
Thermal Plants				
Heat Rate	kcal/kWh	2,600	1,820	-30%
Unavailability	%	52%	29%	-44%

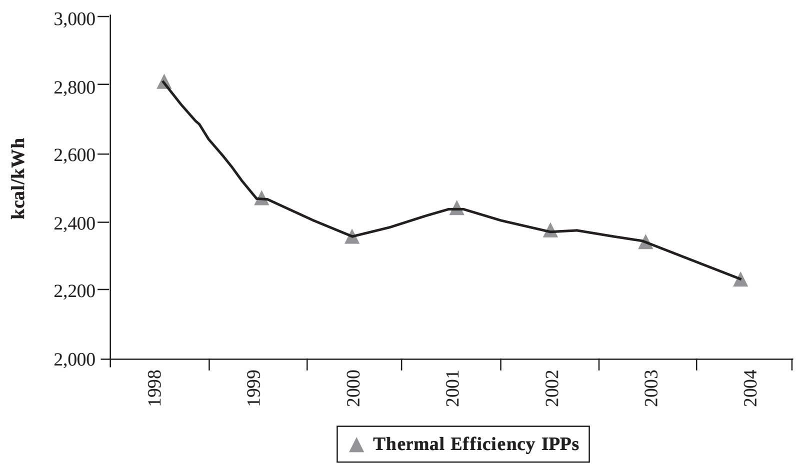
Source: CAMMESA Annual Report 2004.

Figure 1.8A: Dominican Republic – Supply Curve (fuel prices of January/2001)



Source: Authors´ calculations.

Figure 1.8B: Honduras – Thermal Efficiency IPPs



Source: Statistical reports of Empresa Nacional de Energía Eléctrica (ENEE).

At the distribution level, improvements in economic regulation (application of price cap regulation, costs based on an efficient operation, and penalties for low quality of service), provided the incentives to increase labor productivity, reduce distribution losses and improve quality of service to end users. The distribution utilities had the opportunity to increase profits by improving productive efficiency and quality of service.

The evidence shows that private operators in Argentina, Brazil, Chile, Colombia and Peru were able to improve labor productivity by more than 100 percent and reduce total distribution losses by about 50 percent, in six years, after they took control of the largest Discoms in these countries (Table 1.5). Substantial improvements in labor productivity are also influenced by the policy of outsourcing noncore services adopted by most private operators but, in any event, the new operators reduced operating costs substantially.

Table 1.5: Efficiency Improvement Distribution

			Distribution Losses (%)			*Labor Productivity* [a/]		
		Year Privatized	*Pre-privatization*	*Post-privatization*	*% Change*	*Pre-privatization*	*Post-privatization*	*% Change*
Argentina								
	Edenor	1992	27.6%	10.7%	-61%	2.0	4.5	125%
	Edesur	1992	27.0%	10.0%	-63%	1.7	3.8	124%
Brazil								
	12 Distribution Companies	1995-1998			2.1	5.4	157%	
Chile								
	Chilectra	1987	19.8%	10.6%	-46%	1.4	3.5	150%
Colombia								
	Codensa	1997	23.0%	10.2%	-56%			
	Epsa	1997	22.0%	14.6%	-34%			
Peru								
	Edelnor	1994	20.6%	10.4%	50%	509	1,066	109%
	Luz del Sur	1994				426	1,000	135%

Sources: Argentina (Pollitt, 2004), Brazil (Motta, 2003), Chile (Fischer, 2002), Colombia (Mercado, 2004), Peru (Torero, 2001).
a/ Sales in GWh per employee, except for Peru in # customers/employee.
Pre-privatization: First year of operation as private companies.
Post-privatization: 6 years after.

It could be argued that these selected cases included only successful interventions, but the evidence of a larger sample shows significant efficiency improvements. A recent World Bank policy research working paper (Andres et al, 2006) provides performance indicators for a sample of about 84 privatized Discoms in Argentina, Bolivia, Brazil, Chile, Colombia, El Salvador, Guatemala, Nicaragua, Panama and Peru. Although the improvements are less impressive than for the selected cases, changes in the mean values of the indicators show that labor productivity increased about 38 percent, distribution losses declined by 10 percent and quality of service improved by more than 14 percent (Table 1.6).[2]

The analysis of the changes in total system losses at the country level, as an indicator of the impact of reform on efficiency, can be misleading. In the case of the Central American countries (Table 1.7), it would indicate that there were minor efficiency improvements in Nicaragua and Honduras, while the condition of losses in El Salvador and Guatemala deteriorated. However, the real story is different: total system losses in Honduras and Nicaragua are high and the Discoms (a private company in Nicaragua and a SOE in Honduras) have not been able to control distribution losses. On the other hand, total system losses in Guatemala and El Salvador are relatively low and relative changes are influenced by transmission losses. These results mask the fact that distribution losses of the main private distributors in El Salvador have been kept below

[2] Quality of service was measured by the frequency and duration of supply interruptions per customer and per year, which captures the impact of planned and forced outages in generation, transmission and distribution. The data were normalized (100= performance in the first year of privatization), pre-privatization data corresponds to a period that starts at the time when the reform was announced and ending one year after the privatization was awarded and post-privatization covers three years after privatization. The differences in mean values are significant at 99 percent confidence level.

Table 1.6: LCR – Efficiency and Quality of Electricity Distribution Impact of Privatization

		Pre-privatization	*Post-privatization*	*Difference*
Efficiency				
	Customers/Employee	103.3	147.4	40.8
	GWh/Employee	100.0	135.3	37.6
	Distribution Losses (%)	98.7	87.8	-9.8
Quality				
	DEC	100.3	72.4	-25.3
	FEC	98.6	82.7	-13.6

Source: Andrés et al. 2006.
DEC: Annual average duration of interruptions per customer.
FEC: Annual average number of interruptions per customer.

Table 1.7: Efficiency Improvements Distribution

	Year Privatized	*Distribution Losses (%)*		
		Pre-privatization	Post-privatization	% Change
Costa Rica	No	10.7%	9.6%	-11%
El Salvador	1998	11.5%	13.6%	18%
Guatemala	1998	14.4%	16.9%	17%
Honduras	No	23.4%	23.0%	-1%
Nicaragua	2000	31.0%	29.9%	-4%
Panama	1998	22.5%	15.9%	-29%

Source: Prepared by authors based on Economic Commission for Latin America and the Caribbean (ECLAC) data in Web page.
Note: Pre-privatization: two years before privatization date; post-privatization: six years after privatization date.

7.5 percent during the past five years. On the other hand, the results also show that performance is not related with ownership; countries that kept a vertically integrated monopoly have different performances (Costa Rica versus Honduras) as well as countries that reformed and privatized (Panama versus Nicaragua).

FISCAL IMPACT OF REFORM

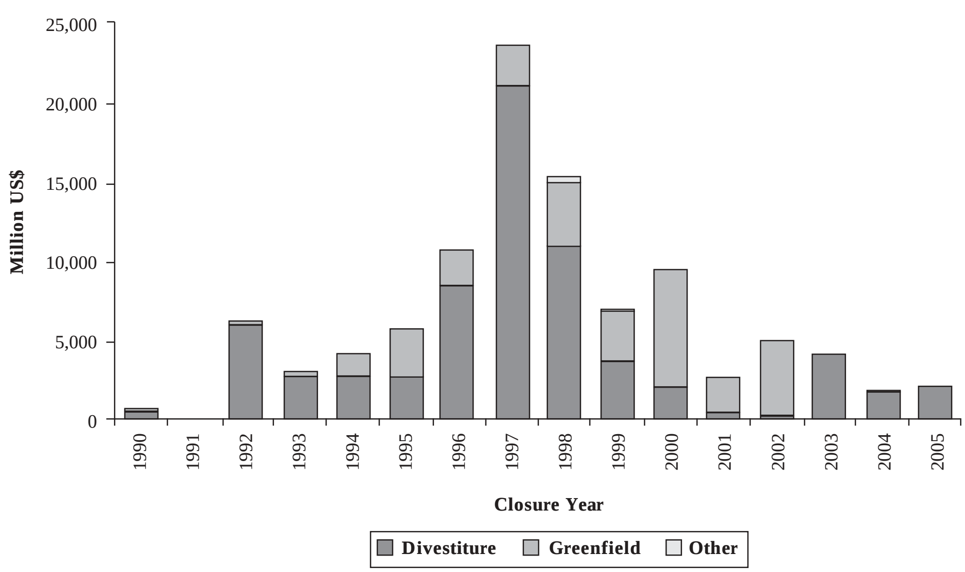
Ideally, an analysis of the fiscal impact of reform in LCR should look at changes in the net transfers from the national budget to the electricity sector: direct subsidies and transfers from the national budget to cover operating and capital expenditures and support debt service, minus revenues from divestiture of State-owned assets, and dividend payments and taxes from the SOEs. The information needed to complete this analysis is not available and we used a simpler approach based on the analysis of private investment in electricity during the reform process, which has a direct fiscal impact: it usually reduces the transfers from the national budget to SOEs, and increases government revenues. This analysis is complemented with comments on the fiscal impact of universal subsidies in some countries that have not implemented cost-covering tariffs.

The Private Participation in Infrastructure (PPI) database of the World Bank, one of the most comprehensive sources of information for private investments, was used for this analysis. It records investment in facilities and in government assets in the year of financial closure or when the transaction takes place (total investment is usually lumped in one year). The database has some limitations: it does not have a good coverage of small projects due to lack of publicly available information; it does not record private investment but total investment in infrastructure projects with private participation; and does not record renegotiations of committed investment that is not publicly available. Therefore, investment figures should be used as rough estimates to analyze trends.

The pattern of total private investment in electricity in LCR from 1990-2005 illustrates the up and downs of the power sector reform process in the region (Figure 1.9). Total investment was about US$103 billion, equivalent to an average of US$6.4 billion per year. About US$60 billion of total investment was in divestiture of public assets – capitalization of existing SOEs, sale of shares, sale of assets and concessions – which enter the government coffers or are used to rehabilitate and expand existing facilities. Investments in divestitures peaked at about US$21 billion in 1997 at the time of privatization of major distribution assets and faded away by 2001 due to external factors (economic and financial crisis in Argentina, corporate scandals and market failures in developed countries) and deficiencies in the design and implementation of market reforms that increased the risk for private investors (see analysis in page 58). Investment in greenfield projects has been more stable during 1995-2002 instead of last ten years, averaging about US$3.4 billion and never dropping below US$1.8 billion (Figure 1. 9). Greenfield generation projects are less risky if protected by a long-term PPA.

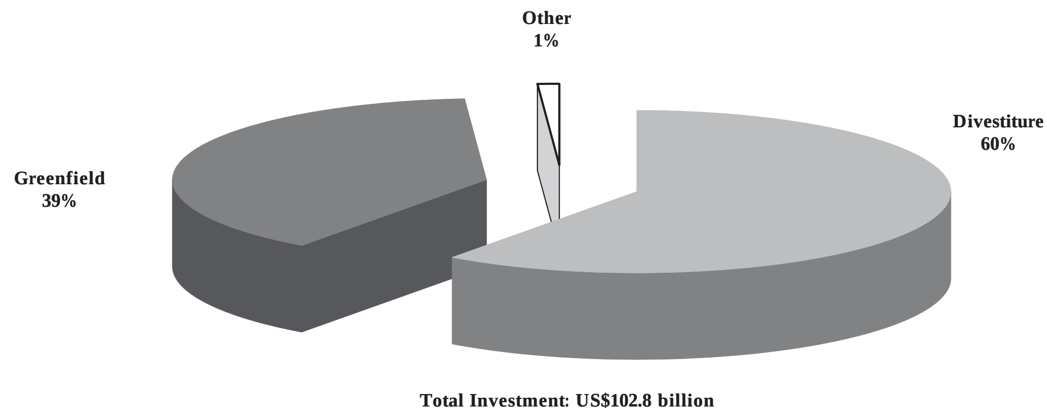
Private investment in generation has been more stable than investments in distribution. About 50 percent of private investment in 1990-2005 was in generation, 40 percent in

Figure 1.9A: LCR – Annual Investment in Electricity Projects with Private Participation



Source: The World Bank, PPI database.

Figure 1.9B: LCR – Investment in Electricity Projects with Private Participation 1990-2005

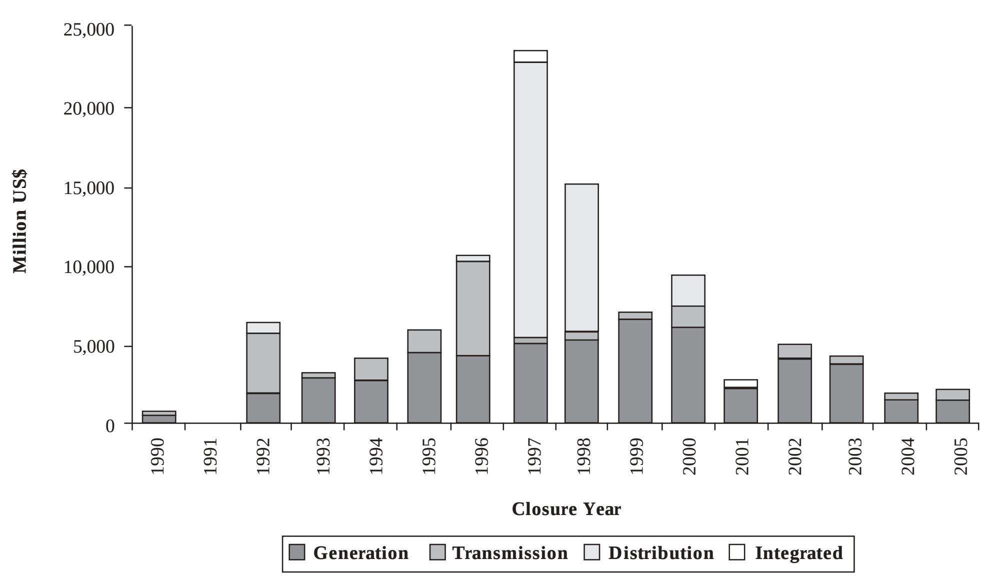


Source: The World Bank, PPI database.

distribution and 6 percent in transmission. All investments in distribution are divestitures and about 70 percent of divestitures are investments in distribution. Therefore, investments in distribution follow about the same pattern of investment in divestitures, peaking in 1997 and dwindling by 2001. Investments in generation have been more stable since 1993, but have decreased during the past five years, when many greenfield investments were made in transmission projects in Brazil (Figure 1.10).

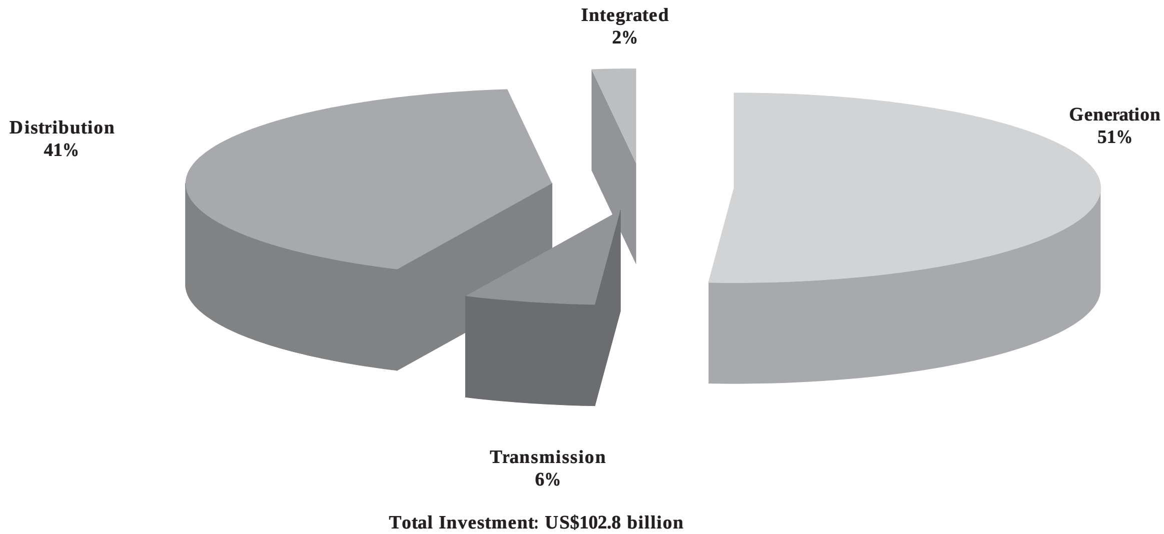
Private investors experienced difficulties in some countries in the region, which is reflected in the projects that have been cancelled or are in the distress category, defined as projects where the government or the operator has either requested contract termination or are in international arbitration. According to the PPI database, about 17 percent of the total private investment from 1990-2005 is in the distress category or has been cancelled (Figure 1.11),

Figure 1.10A: LCR – Annual Investment in Electricity Projects with Private Participation



Source: The World Bank, PPI database.

Figure 1.10B: LCR – Investment in Electricity Projects with Private Participation 1990-2005

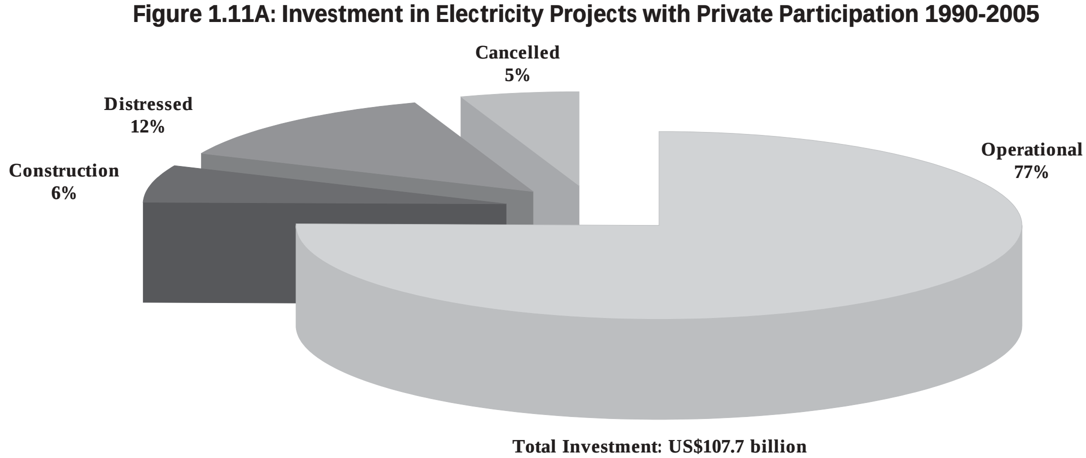


Source: The World Bank, PPI database.

and these projects are located in a few countries, mainly Argentina and Brazil. In Argentina, after the economic and financial crisis that caused substantial financial losses to electricity companies, about 55 percent of the total private investments, amounting to more than US$9 billion, are in the distressed category. In Brazil, corporate control of Companhia Energetica de Minas Gerais S.A**.** (CEMIG) by a private minority shareholder was reversed in the courts. Other notorious cases are the withdrawal of private investors of Guyana Power & Light in Guyana, and Edesur and Edenorte, the main Discoms in the Dominican Republic, after the operators were unable to control electricity losses in a hostile political environment (Figure 1.11).

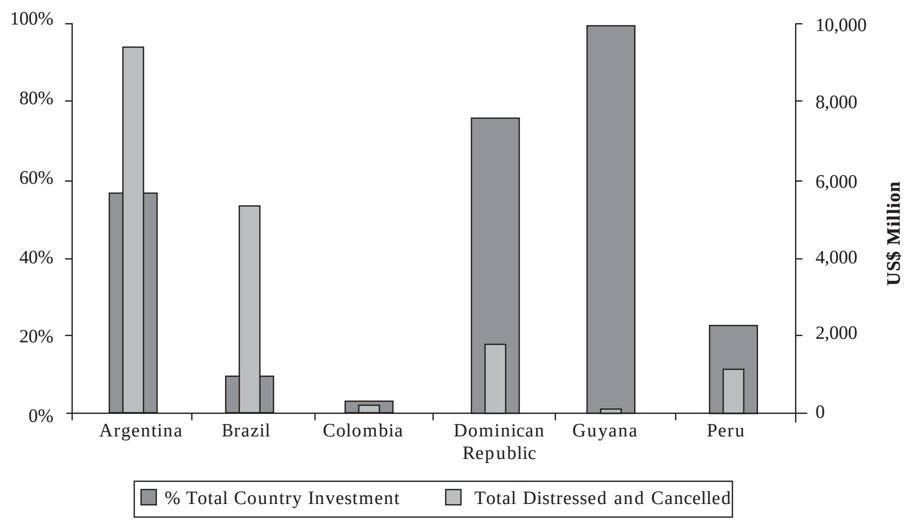
Private investment in 1990-2005 concentrated in a few countries, but was substantial in the reforming countries, in relative terms to market size. About 91 percent of the total private investment from 1990 to 2005 was in six countries (Brazil, Argentina, Chile, Mexico, Colombia

Figure 1.11A: Investment in Electricity Projects with Private Participation 1990-2005



Source: The World Bank, PPI database.

Figure 1.11B: LCR – Distressed and Cancelled Private Investments



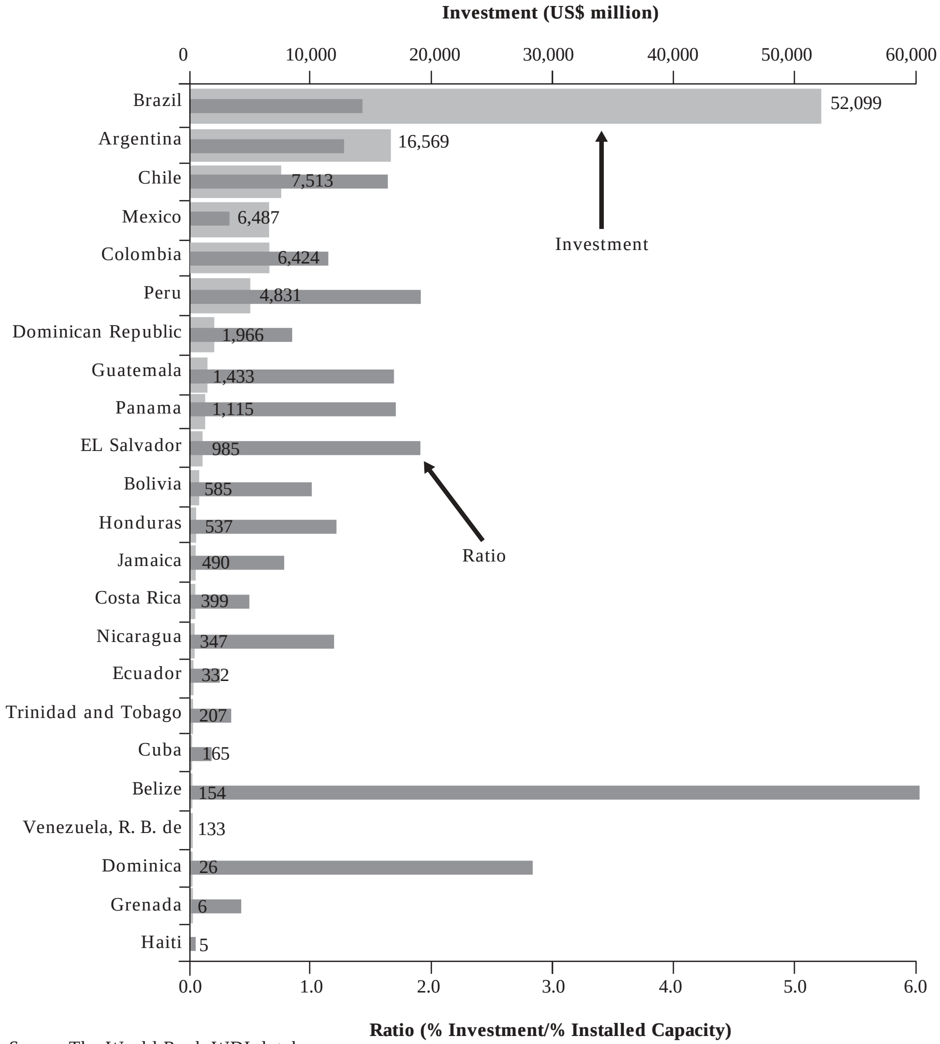
Source: The World Bank-WDI database.

and Peru), with Brazil taking about 50 percent of the total investment. However, in relative terms to the size of the power market of each country (measured by the installed capacity), the investment in most reforming countries was significant (except for Ecuador that introduced market-oriented reform but did not implement privatization), while private investment in nonreformers was marginal (Venezuela, Mexico, Trinidad and Tobago and Costa Rica) (Figure 1.12).

The distribution of investment between subregions illustrates differences in approaches to engage private capital. The Southern Cone countries took about 75 percent of the total private investment in the region from 1990-2005, 60 percent in generation, 92 percent in transmission and 87 percent in distribution. The relatively larger participation of the Southern Cone in distribution and transmission can be explained by the successful privatization program of Discoms in Brazil with large premiums paid over the base price and recent investments in greenfield transmission lines in Brazil. Mexico has a significant participation in generation as a result of its policy of relying on IPPs to develop thermal generation. Central America does not have any participation in transmission due to the policy adopted in these countries of keeping transmission under control of State-owned companies (Figure 1.13).

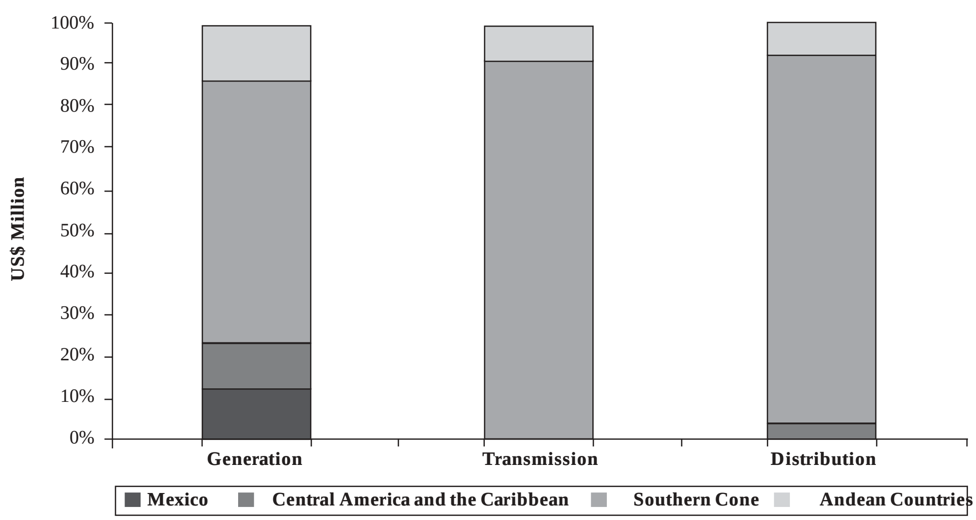
Currently, the participation of the private sector as a provider of electricity services in many reforming countries is high. Private companies have a high market share in generation and T&D (higher than 70 percent) in the countries that advanced more in the implementation of the market reform and privatization program (Chile, Bolivia, Argentina, Panama and Peru), medium share (40 percent to 70 percent) in Nicaragua, El Salvador, Guatemala, the Dominican Republic, Brazil and Colombia, and low in the countries that did not reform (Mexico, Costa Rica and Paraguay) or that did not implement the reform program that was initially adopted (Ecuador, Honduras, Uruguay and Venezuela) (Table 1.8).

Figure 1.12: LCR – Private Investment in Electricity 1990-2005



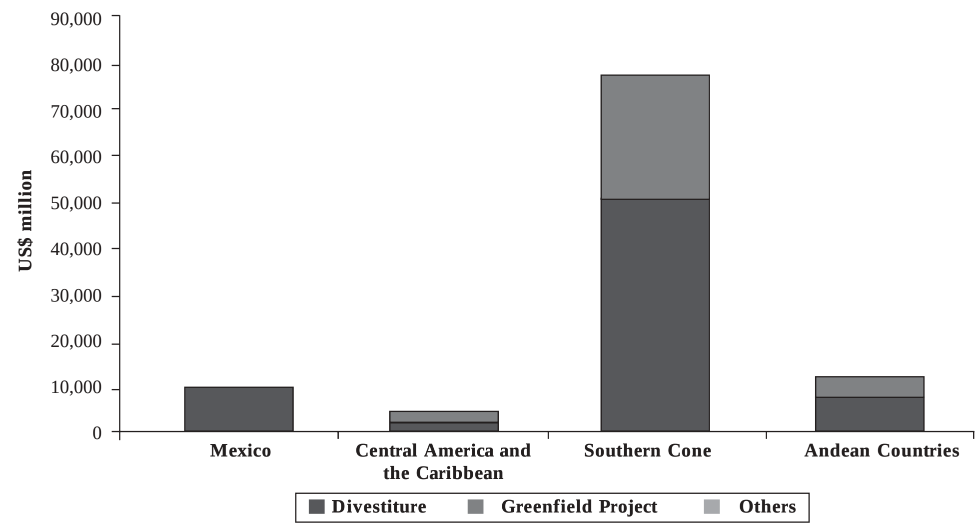
Source: The World Bank-WDI database.

Figure 1.13A: LCR – Private Investment by Subregion and Segment 1990-2005



Source: The World Bank-WDI database.

Figure 1.13B: LCR – Private Investment by Subregion and Type 1990-2005



Source: The World Bank-WDI database.

Table 1.8: LCR- Private Participation in the Power Sector – Estimate Based on 2004-05 Information

	Countries	Generation	Transmission	Distribution
High	Argentina	80%	100%	60%
	Bolivia	100%	100%	93%
	Chile	100%	100%	100%
	Panama b/	89%	0%	100%
	Peru	66%	100%	71%
Medium	Brazil	26%	10%	64%
	Colombia	57%	3%	46%
	Dominican Republic a/	83%	0%	32%
	El Salvador	64%	0%	100%
	Guatemala	68%	0%	91%
	Nicaragua a/	69%	0%	100%
Low	Costa Rica c/	12%	0%	0%
	Ecuador		0%	0%
	Honduras c/	65%	0%	0%
	Mexico c/	19%	0%	0%
	Paraguay	0%	0%	0%
	Uruguay	0%	0%	0%
	Venezuela, R.B. de d/		14%	

Source: Authors' calculations.
a / Reserves transmission and hydro generation to State-owned companies.
b/ Reserves transmission to State-owned companies.
c/ Vertically integrated SOEs with private participation in IPPs.
d/ Several vertically integrated monopolies.

SOEs still play a major role in many of the reforming countries in the region:

- Transmission is a strategic activity assigned to SOEs in all Central American countries, and is controlled by SOEs in Colombia and Brazil;
- Hydroelectric generation is still, by and large, in the hands of SOEs in most Central American countries (except Panama) and in Brazil;
- In Colombia, Brazil and Argentina, the SOEs (mostly provincial and municipal enterprises) control about 50 percent of distribution; and
- In Colombia, about 40 percent of the generation is in the hands of municipal and national SOEs.

FISCAL IMPACT OF TARIFF LAGS AND SUBSIDIES

The application of cost-covering tariffs and targeted subsidies has faced difficulties mainly in countries that required substantial tariff rebalancing in a period of increasing generation costs or economic stress (see section on new issues and lessons learnt). Lags in adjusting electricity tariff to cover the cost of service and the application of social tariffs that are poorly targeted had an important fiscal impact, and also were a contributing factor to the retrenchment of private investments in the region.

The evidence available for a group of countries in the region shows that social tariffs apparently do no have a significant fiscal impact. The structure and impact of social tariffs were analyzed recently for a selected group of countries (Foster, 2006). In most countries in the group, the cost of subsidies included in social tariffs was financed, by and large, by cross-subsidies from other consumer groups. Only in the case of Honduras was direct subsidy fully financed by fiscal resources (Table 1.9). However, the case of Guatemala is misleading because the social tariff was financed by a State-owned generation company, using the economic rent of hydroelectric plants. In this case, the real fiscal impact has to be measured by the financial losses of the generation company owned by the government.

Table 1.9: LCR – Social Tariffs and Generalized Subsidies

	Social Tariffs		*Tariff Lags*	
	Total Annual Cost (US$mn)	*% Fiscal Cost*	*Total Annual % Cost (US$mn)*	*% GDP*
Argentina [a/]	<20	0%		
Colombia [a/]	250	20%		
Ecuador [b/]			300	0.9%
Guatemala [a/]	50	0%		
Honduras [c/]	15	100%	112	1.6%

Source: a/ (Foster,2006), b/ (Centro Nacional de Control de Energía [CENACE]), 2005), c/ (The World Bank,2007).

AFFORDABLE ACCESS FOR THE POOR

Electricity coverage increased in the period 1992-2005 from about 75 to 90 percent, which represents about 156 million new people with electricity service. The poverty rate decreased from 48.3 to 44 percent in 1990-2002, but the number of poor people in the region increased from 200 to 221 million – 146 million in urban areas and 75 million in rural areas. In spite of substantial improvements in electricity coverage, in 2005, there were about 50 million people, almost all poor and in rural areas, without electricity. The number of poor people living in urban areas has increased constantly as a result of the rural-urban migration trend (ECLAC, 2005).

The lack of access to affordable modern energy services for the poor has been, and remains, a problem in the region. The combination of a large population of poor people living in urban areas and connected to the grid, and a large population of poor people without electricity in rural areas, creates two different problems of access to the poor: affordability of electricity service for the poor population that already has service, and accessibility to electricity service for the poor population without service, mostly in rural areas. Access to affordable energy services for the poor has a high political priority due to its strong links with poverty reduction by boosting productivity and income and improving health and education (Saghir, 2005).

Power sector reform affected the poor in varied and often complex ways, and it is difficult to draw a direct linkage between reform and the poor. Poor households benefit directly from increases in access to electricity service, electricity subsidies, lower supply costs related to gains in productivity and better quality of service; and indirectly from economic development. They may lose when their cost burden of electricity service increases as a result of having formal electricity connections and paying cost-covering tariffs with reduced subsidies. However, the data available to measure the impact of reform on the poor in the region are weak and usually inadequate to do a proper “before and after” or “with and without” analysis (Estache. 2000).

This Section reviews some of the evidence available on the application of social tariffs and subsidies, intended to provide affordable electricity service to the poor, and on the impact of reform on the poor in selected countries. The conclusions are mixed: although poor people in the region benefited from the substantial improvements in electricity coverage, and cost and quality of service, in some countries, the poor people were not the main beneficiaries of reform.

Electricity Subsidies and Social Tariffs

Electricity sector reform in LCR adopted, in most cases, the principles of competitive pricing, cost-covering tariffs, and transparent and targeted price subsidies as instruments to improve efficiency in supply and demand, and provide affordable electricity access to the poor. One of the objectives was to eliminate the substantial tariff distortions that existed in the 80s, mainly universal subsidies and the application of implicit, nontransparent and inefficient cross-subsidy schemes. The new laws and regulations established explicit subsidies or social tariffs aimed to protect low-income and vulnerable groups (for example, cross-subsidies with caps on discounts and surcharges, direct subsidies to low-income consumers, subsidies to pensioners, and so on, and so forth).

Although substantial progress was made in many countries to reduce tariff distortions and nontransparent electricity subsidies, many of the reforming countries still apply social tariff schemes which are poorly targeted. Recent papers on the performance of subsidies in a selected group of countries (Colombia, Guatemala, Honduras and Peru) show high inclusion and exclusion errors and leakage rates[3] (Table 1.10). The elimination of inefficient subsidies proved to be a difficult task due to political and economic constraints, and the impact of external shocks on the cost of service in local currency (steep increase in oil prices, economic crisis).

Poor people captured a small portion of the value of the subsidies that were poorly targeted, and these financial resources could be better employed in financing new connections in rural areas. High inclusion errors and leakage rates in the case of Guatemala and Honduras are explained by the fact that a high monthly electricity consumption (which includes about 85 percent of consumers) is used as the sole criterion to allocate subsidies. High exclusion

Table 1.10: LCR – Social Tariffs

	Argentina b/	*Brazil* d/	*Colombia* b/	*Guatemala* b/	*Honduras* a/	*Peru* c/
Direct Subsidy						
Limit (kWh/month)	100-200	220		300	300	
Criteria	Variable by Province, Socio-economic Condition	Variable by Region		Consumption	Consumption	
% Discount	25-75%	10-65%		~50%	~10%	
% Consumers		37%		87%	84%	
Cross-subsidy						
Limit (kWh/month)			200		300	100
Criteria		Consumption and Socio-economic Condition		Consumption	Consumption	
% Discount		15-50%			20-55%	25-63%
% Consumers					84%	60%
Performance						
Inclusion Error	39%		51%	65%	60%	47-59%
Exclusion Error	94%		6%	60%	55%	4-16%
Leakage Rates			69%	90%	81%	58%

Source: a/ [The World Bank, 2007] and [Foster,2006], b/ [Foster,2006], c/ [Organismo Supervisor de Inversión en Energía [OSINERG], 2005], d/ [Pantanali,2006].

[3] Errors of inclusion: percentage of subsidy beneficiaries who are not poor; exclusion: percentage of the poor who are not subsidy beneficiaries; leakage rate: proportion of the total subsidy expenditure received by the nonpoor.

errors in the case of Guatemala and Honduras are reflected by the fact that most poor people in rural areas do not have electricity access. A low exclusion error in Colombia is explained by the relatively high coverage and a subsidy allocated on the basis of electricity consumption and socioeconomic condition. The subsidy scheme in Argentina is better targeted (based on socioeconomic conditions) but shows a large exclusion error due to its modest scale (Foster, 2006, 2004).

The problem of affordability of basic utility services in the region seems to be limited only to poor people. A recent study suggests that only about 20 percent of households in the region would have to pay more that 5 percent of their income for water and electricity services priced at cost-recovery tariffs. Only in the lower-income countries (Bolivia, Honduras, Nicaragua and Paraguay), about 50 percent of household would have an affordability problem (Foster, 2006).

THE CASE OF ARGENTINA

The case of Argentina, with emphasis on the metropolitan area of Buenos Aires, has been discussed extensively (Arza, 2002; Bouille, 2002; Haselip, 2003; Delfino, 2001), and most analysts argue that the poor were not the main beneficiaries of the reform.

The distribution between consumer classes of the substantial improvements in the productive efficiency in the electricity sector of Argentina from 1992 to 1998 was regressive. Energy prices in the wholesale power market fell by about 50 percent, and average residential electricity prices decreased by about 19 percent in this period (Ente Nacional Regulador de Electricidad [ENRE], 1998). However, while prices for high consumption industrial and residential consumers dropped by 70 percent and 33 percent, respectively, prices for low consumption residential consumers declined only by 1.6 percent (Bouille, 2002). This is manifested in the changes in consumer welfare by income classes: while welfare increased by about 17 percent for the richest, it decreased by 10 percent for the poorest (Delfino, 2001).

These results are not surprising as cross-subsidies and electricity tariffs below costs were common in the pre-reform period. The new regulatory framework required that electricity tariffs reflect the cost of a reliable and adequate quality electricity supply and, then, average residential tariffs may increase and cross-subsidies tend to disappear. Therefore, the average tariff for poor people connected to the grid usually increased after the reform.

However, some analysts argue that the reform hurt the middle class relatively more than the poor in countries where the structure of generalized subsidies (pre-reform) benefited mostly middle-income households. They also argue that cost-covering tariffs improve the financial viability of efficient electricity providers, and help to expand access to quality service for poor households, which may compensate for the price increases (Estache, 2001b).

The distribution of benefits between stakeholders is also influenced by the rules used to regulate wholesale prices, and by the effectiveness of the regulator. In the case of Argentina, the new privatized Discoms received five-year fixed price energy supply contracts that covered up to 50 percent of projected demand. Therefore, half of the savings obtained by the drop in wholesale prices were not passed on to consumers, and were retained by the generators with contracts.

Electricity coverage for low-income consumers in the metropolitan area of Buenos Aires increased from 66 percent in the late 80s to 99 percent in 1997 (Arza, 2002). Although this may be a major achievement of reform, this increase was due largely to the formalization of connections in urban slums rather than the expansion of electricity service to rural areas. The new privatized Discoms initially tried to reduce high electricity losses (27 percent) by cutting illegal connections off from service, but in response to a negative popular reaction, the federal and provincial governments and the Discoms signed a four-year agreement, whereby the governments reimbursed part of the cost of stolen energy and provided subsidies to the distributors to cover the investment cost of the normalization of electricity service. The program worked well and, by 1997, the distributors had legalized about 650,000 connections and reduced distribution losses to about 10 percent (ENRE, 1998). Some critics argue that actual payments for electricity for these low-income consumers increased after the reform, paying nothing for something before the reform took place to paying something for a better service after the reform. However, this ignores the benefits of improvements in the quality and safety of service, and of the elimination of the costs paid to providers of illegal connections.

Although the distribution concession contracts included an obligation to serve all potential customers within the concession areas, private investors lacked incentives to expand services to rural areas. This was compensated in 1995 by a five-year rural electrification program Programa de Abastecimiento Eléctrico a la Población Rural Dispersa de Argentina (Program for Electricity Supply to the Rural Population of Argentina) – PAEPRA to grant distribution concessions to serve isolated populations, based on investment subsidies.

THE CASE OF CHILE

Power generators in Chile did not capture the benefits of substantial improvements in productive efficiency in the late 80s. Most benefits of declining wholesale prices were transferred to the consumers in the regulated market as generation prices included in tariffs reflect expected marginal costs, and generators are exposed to competitive pressures to sell energy to large consumers at a lower price. As a result, the return on equity (RoE) of the main generators increased moderately to 15.7 percent since privatization from 1988 to 1995 (Fischer, 2002), and has been modest in the early 2000s with the commissioning of new gas-fired thermal plants.

After more than 15 years of reform in Chile, the regulatory process has been relatively effective in transferring most efficiency improvements in distribution to consumers. The distribution margin allowed in the tariff formula for Chilectra has been reduced in real terms by 18 percent in 1992, 5 percent in 1996, 18 percent in 2000 and 8 percent in 2004.

Initially, the reduction in the margin did not match the efficiency gains achieved after privatization, and the Discoms were able to increase their RoE to 32 percent in 1996-98. Later, in 2002, when the distribution margin was reduced, the RoE decreased to about 14 percent (Fischer, 2002 and Pollitt, 2004).

Chile has implemented a successful rural energy program. In the early 90s, electricity coverage in urban areas was 97 percent, while in rural areas it was 53 percent. To increase coverage in rural areas, the government launched a rural electrification program in 1994, which set up a special fund. The fund was financed with tariff surcharges to allocate – by competitive tendering procedures – a one-time direct subsidy to private Discoms to cover part of the investment costs. Electricity coverage in rural areas increased to 86 percent in 2002, and 92 percent in 2005 (Jadresic, 2002 and CNE, 2006).

Low-income groups in urban areas also benefited from increased access to electricity services during the reform process. From 1988 to 1998, exclusion from electricity service of households in the two lower deciles in income per capita in greater Santiago was reduced from about 29 to 7 percent and from 20 to 4 percent, respectively. Although the growth of disposable income in this period was a factor that contributed to the increase in access, a large portion of the new connections can be attributed to improvements in the investment capacity of privatized utilities (Estache et al., 2000).

THE EXPERIENCE OF OTHER COUNTRIES

In spite of substantial improvements in productive efficiency, and in electricity coverage of privatized Discoms in Peru, it was necessary to implement a major tariff rebalancing that represented a substantial tariff increase for residential consumers. From 1994 to 1998, the Discoms in Lima increased coverage from 76 percent to about 100 percent, reduced distribution losses from 20.6 to 12.4 percent and increased labor productivity by 100 percent. However, after privatization, it was necessary to make major adjustments in electricity tariffs to reflect costs. The average residential price increased 200 percent from US¢4 to 12/kWh from 1993 to 1997 while average industrial prices increased 33 percent from US¢4.5 to about 6/kWh. After the tariff rebalancing was completed in 1997, residential prices had decreased in real terms by about 7 percent in 2005.

In Colombia, similar to the case in Peru, it was necessary to make substantial adjustments in the electricity tariff structure to reflect the cost of service and reduce cross-subsidies. The new political constitution of 1991 established that electricity tariffs should cover economic costs of supply, and that low-income consumers should receive explicit subsidies from other consumers and from the national/regional budgets. New laws that reformed the sector in 1994 established specific targets to subsidize up to 50 percent of the basic electricity consumption of low-income residential consumers, financed by tariff surcharges of up to 20 percent on high-income residential consumers, commercial and industrial consumers (including large unregulated consumers) and contributions from the national/regional budgets.

A major tariff rebalancing and adjustment program was implemented after the reform was approved in 1994. Between 1995 and 2000, the average industrial electricity price was reduced by about 44 percent in real terms, while average residential prices increased by about 46 percent from 1995 to 2002. In the residential sector, tariff surcharges for high-income consumers were reduced from about 100 to 20 percent, while subsidies for the lowest income group increased from 40 percent to about 45 percent from 1991 to 2002 (Económica Consultores, 2004). These tariff adjustments took place in a period in which wholesale prices did fluctuate in response to variations in marginal generation costs but did not increase in real terms at the end of the period. Based on these results, it could be argued that the reform was regressive, but this conclusion ignores the fact that sector finances improved, electricity coverage increased from 76 to 90 percent and that fiscal resources were liberated and could be allocated to social programs.

New Issues and Lessons Learned

The previous Section focused on a quantitative analysis of the impact on the main drivers of the reform and showed that many countries were successful in mobilizing private participation in the power sector. It also showed that, in many cases, the combination of market mechanisms and private participation resulted in substantial improvements in the operating efficiency and quality of service in generation and distribution, and increases in electricity service coverage that benefited the poor. However, this analysis also detected some problems: private participation declined since 1997 and the reform program in many countries did not focus on providing access to affordable energy services for the poor because it was more concerned with improving operating efficiency, rebalancing tariffs to reflect costs and reducing the fiscal burden. Nevertheless, this is a partial assessment of the reform and does not deal with the specific difficulties experienced by many countries in consolidating the reforms in the early 2000s; difficulties that raised concerns about their sustainability. The assessment of these issues is well documented and there is broad agreement on the diagnosis and the lessons learnt (Millán, 2006; Besant-Jones 2006). In this Section, we summarize the main issues and lessons.

MAIN ISSUES

Retrenchment of Private Investment

The previous Section showed that private participation in divestiture of government electricity assets in the region peaked in 1997 and collapsed in the early 2000s, while investment in greenfield projects remained at about the same level. This fact raises concerns about the feasibility of attracting private capital to finance future investment needs of the power sector in the region at the time when the fiscal space for public sector investment has been reduced.

The collapse of private participation in power investments has been analyzed recently (Herz, 2005; Deloitte Touche Tohmatsu, 2004). The slowdown in private investment in electricity appears to follow the same pattern of total private capital flows, and can be explained by external factors, like the conclusion of major divestiture programs in the second half of the 90s (Brazil, Colombia, Central America), the financial losses of key international electricity investors after the economic crisis in Argentina in 2001, the Enron scandal and the destruction of economic value of power utilities in developed countries.

A survey of international investors in the power sector revealed that investors identified the following high priority conditions to attract and retain foreign investment in the sector: adequate tariff levels and collection discipline, stability and enforceability of contracts and the rules of the game, and minimal government interference (Lamech, 2003). Although external factors, which were not under the control of the electricity sector authorities, played a role in the retrenchment of private capital, the crisis also revealed that in many countries the basic conditions for private participation were not met due to deficiencies in the design and implementation of market reforms (discussed below), which combined with external factors, did not allow private investors to earn an adequate risk-adjusted rate of return on investment.

Government interventions undermined the credibility of reforms. The threat of large tariff increases and energy shortages, due in part to external shocks (increases in international fuel prices, droughts and economic crisis), prompted government interventions to change market rules and control prices, which undermined the authority of regulatory institutions and the credibility of government commitments, and increased the risks for private investors. This process was more evident in countries with a weaker ownership of the reform.

The application of cost-covering tariffs and transparent subsidies has faced difficulties in countries that required substantial tariff rebalancing in periods of increasing generation costs or economic stress. In the Dominican Republic, with a power generation system dependent on imported fuels, new regulations established a gradual transition to cost-covering tariffs and the implementation of tariff adjustments to reflect changes in fuel prices, inflation and devaluation. However, the government tried to mitigate the tariff impact of increases in fuel prices by renegotiating the initial energy supply contracts and introducing generalized subsidies to be financed by the national budget and the rent of hydroelectric generation under the control of a SOE. These actions were not sustainable: the government ran out of money, payments in the supply chain collapsed, which led to major blackouts and riots (Manzetti, 2006). Honduras experienced a similar situation and the power sector is now facing an unsustainable financial crisis due to high electricity losses, generalized subsidies and high variable costs of a generation system dependent on imported fuel oil (The World Bank, 2007).

In Guatemala, the government used the economic rent of hydroelectric resources under the control of a SOE to finance a generalized subsidy for residential consumers, called a "social tariff," created by the national congress to mitigate the tariff impact of fuel price increases on the high cost of energy purchased from thermal generators under PPAs. When the regulator approved a resolution to reduce the subsidies to higher income groups and ensure its sustainability, this action was challenged before the high court, which finally decided to turn down the decision and requested the dismissal of the regulator (Benavides, 2004).

Argentina is a good example of opportunistic behavior. After the economic crisis of 2001 and a 60 percent devaluation, the government froze electricity tariffs in pesos, breaching the terms of the concession contracts, and forced the Discoms to make critical investments. Argentine Discoms financed distribution investments in the 90s with dollar-denominated debt and are facing declining net margins and cutting back on investments to meet demand growth. In 2007, the government approved an ad hoc 20 percent tariff increase for the Discoms of Buenos Aires (Bear Stearns, 2007).

New power market models demanded strong institutions, political commitment and market conditions that were not available in many countries. The application of cost-covering tariffs, transparent subsidies and political commitment to enforce metering, billing and collection were basic principles adopted for the privatization of Discoms. To provide credibility and stability to the application of these principles, these were established in the law and an independent regulator was made responsible for their application. These provisions were expected to mitigate the risks of opportunistic behavior by the government to appropriate private capital.

Enforcement of metering, billing and collection had difficulties in countries or regions with a history of political patronage and a culture of nonpayment. In the Dominican Republic and Guyana, private investors with international experience in operation were not successful in controlling electricity losses, improving collections and quality of service. After trying an aggressive approach initially to reduce nonpayment and fraud, they decided to pull out as shareholders and operators when it became clear that they did not have political support to enforce collections and control fraud. A private investor in Nicaragua is facing a similar situation. In the Atlantic coast of Colombia, a private operator had major difficulties in reducing losses and improving collections, after trying an aggressive approach initially under a hostile political environment and popular opposition, and is now gradually overcoming these difficulties with the support of the central government and the application of a less confrontational stick and carrot approach with the participation of local communities.

In all these cases, government interventions revealed the importance of electricity as a political commodity as well as the difficulties of developing independent regulatory institutions that are not supported by Latin America legal and political tradition, which is sometimes characterized by political patronage, policy instability and short-time horizons for policy makers. Governments resisted the elimination of subsidies, opposed large rate increases and curtailed regulatory independence if needed (Rufin, 2003).

Inadequate wholesale market designs and operation. Most countries in the region introduced a competitive wholesale market with the participation of generators, Discoms and large consumers. Generators can contract supply of energy with distributors or large consumers

Box 1. 1: Evolution of Some Wholesale Power Markets in LCR

Chile: the pioneer. The wholesale market is composed of: (i) a regulated contract market between generators and Discoms at energy prices calculated on the basis of expected short-run marginal generation costs, complemented with firm capacity prices that reflected the investment costs of a gas turbine; and (ii) a free contract market between generators and large consumers at negotiated prices. Generators settle – in a spot market – the differences between energy contracted and energy supplied in a centralized merit order dispatch. The hourly spot prices correspond to the marginal generation costs. The design of the Chilean wholesale market sacrificed competition in order to promote private investment in generation and distribution. The success of the Chilean wholesale market model in attracting private investment and developing a reliable and low-cost power supply convinced Bolivia, Peru and other countries (the Dominican Republic, Honduras, Guatemala and Nicaragua) to adopt similar models. Recently, in response to the power supply crisis of 1999, the model was modified to introduce long-term contracts as an instrument to facilitate financing of generation projects and ensure adequacy of supply.

Argentina: improving the model. Argentina learned from the Chilean experience that to promote competition it was necessary to unbundle (horizontally and vertically) the industry and establish limitations to cross-ownership. The wholesale power market model of Argentina has similarities but substantial differences with the Chilean model. Economic dispatch is based on variable generation costs, but on biannual declaration of costs by generators. Discoms and large consumers can purchase energy in the spot market, at stabilized prices, to protect Discoms from the volatility of daily spot prices. The market administrator (Compañía Administradora del Mercado Mayorista Eléctrico S.A.– CAMMESA) is not a generator's club, but includes the other market agents. There were other innovations (capacity payments for cold and spinning reserve, congestion prices for transmission).

Colombia: a second generation of wholesale markets. Colombia, which also has a hydro-based generation system, decided to introduce a market with major differences from the Chilean model, similar to the market in England and Wales. Discoms, large consumers and independent marketers can negotiate bilateral contracts, similar to the contracts for differences, which take the prices in the spot market as a reference. Prices in the spot market are determined by a merit order dispatch based on price bids. There is a single node marginal price with payment adjustments for out-of-merit generation due to transmission congestion. Energy payments are supplemented by a capacity charge.

(continued...)

(...Box 1.1 continued)

El Salvador: too good to be true. El Salvador, with a small power market, adopted the most advanced competitive market in the region in 1997: wholesale and retail competition with no restriction on market structure. The system operator dispatches first the bilateral physical contracts and settles the differences in a spot market at prices determined on the basis of price and quantity bids submitted by generators and Discoms. Prices in the spot market are passed through to tariffs and are used to index contract prices. The model experienced difficulties due to lack of competition in the spot market (market power), insufficient incentives to invest in reserve capacity, lack of long-term contracts and volatility of electricity tariffs. The market model was replaced by one similar to other Central American countries.

Brazil: a premature market. The Brazilian generation system is 95 percent hydro, with large interrelated reservoirs. The coordinated operation of the hydroelectric plants is essential to ensure an optimal use of water resources. The model adopted initially comprised a regulated long-term contract market and a spot market supported by a complex mathematical model. Hydroelectric plants can only negotiate in bilateral contracts their contribution to the firm energy of the hydro system (generation with 95 percent probability of being exceeded). The system operator was responsible for the economic dispatch of all plants and the operators of individual plants had to ensure availability. Energy differences were settled in a spot market Mercado Atacadista de Eletricidade (MAE) managed by market agents. Large consumers have freedom of choice to negotiate long-term contracts and to purchase energy in the spot market.

After the energy crisis of 2001, it was essential to ensure a secure and reliable supply, and the market model was segmented in a competitive market (for large consumers) and a regulated market. The regulated market comprises centralized auctions for old energy with the participation of existing generators, and auctions for new generation to meet long-term expected demand, with the participation of investors that compete for the right to build, operate and own generation plants identified by the planning authority in the least-cost generation plan. Each Discom signs PPAs with the winners of the auction for new energy in proportion to demand. Differences between contracts and dispatch are settled in the spot market.

Source: Taken and adapted from Millán, 2006.

and settle the differences between the contracted energy supply and the actual dispatch in a spot market. The basic assumption is that the price of energy, determined by market forces, will provide incentives to mobilize private investment in generation expansion. Box 1.1 presents the evolution of wholesale markets in the region.

Attempts to introduce competition in unsuitable small power markets have been problematic for private investors. Some countries in the region did not meet the minimum requirements of size or structure of the market to introduce workable competition: unbundling of generation, T&D and sufficient number of competing sellers and buyers.

The IPP experience. Many countries in the region were successful in using the IPP option, with long-term PPAs with State-owned companies, to attract private capital in thermal generation in the early stages of the reform. The IPP option mobilized financing and added needed capacity to meet supply shortages. It was effective because it provides comfort to private investors and lenders when they are facing a high degree of country risk and uncertainty. IPPs are generally insulated under the terms of their PPAs, project financing structure and guarantee package against several risks: market, fuel prices, devaluation, inflation, credit and political risks. All rights and obligations of an IPP are established in a contract (PPA), including a payment scheme that ensures that all fixed and variable generation costs will be recovered by the private investor provided that the generation plant is operated efficiently and meets agreed availability requirements. To ensure financial sustainability, a full pass-through of the PPA's costs to tariffs is implemented.

In many countries worldwide, IPPs experienced difficulties (Woodhouse, 2005; Woolf, 2001). Although PPAs do protect private investment, it is not realistic to think that a full pass-through to consumers of the costs of a long-term PPA is sustainable under all circumstances, especially when the price increases are steep due to external shocks or when IPPs are no longer competitive, and the off-taker has to assume substantial stranded costs. Few SOEs have the financial resources to subsidize the differential between the PPA's costs and the generation price that is included in the electricity tariffs, and few governments are willing to spend their political capital in enforcing large tariff increases. Sooner or later, IPPs will be affected by a mounting political pressure.

Many countries in the region that introduced a competitive wholesale market had additional difficulties with the IPP scheme. The new market regulations did not allow an automatic pass-through of the costs of PPAs that did not follow competitive bidding procedures and were higher than the energy prices determined by the market forces. In that case, there were two options: (i) renegotiate the PPA and transfer it to the wholesale market; or (ii) the off-taker, a SOE, represents the IPP in the market, assumes the cost of the PPA and sells the energy of the plant at market prices.

In Guatemala, it was necessary to renegotiate some of the IPPs that were contracted before Discoms were privatized, to transfer these contracts to the wholesale market. Some IPPs agreed to assume the market risks if they were compensated by a five-year extension of the supply contract. The costs of others IPPs that were not willing to renegotiate were assumed and subsidized by a SOE (Benavides, 2004). In the Dominican Republic and Nicaragua, the government did not allow the Discoms to pass-through to consumers large increases in fuel prices, the off-taker temporarily subsidized the price increases using the economic rents of hydroelectric generation, but it had to suspend the subsidy when it ran out of cash and the Discoms were not able to pay to the IPPs, leading to blackouts (Millán, 2006).

In the Dominican Republic, an efficient CCGT burning gas-oil, that was considered to be the least-cost solution at the time, was contracted following competitive bidding procedures. It ran into trouble when it was no longer competitive in the economic dispatch (large increases in gas oil prices). The off-taker, a SOE, tried unsuccessfully to negotiate the contract and had to assume the stranded costs (Dussan, 2003). In Colombia, PPAs signed before the reform by State-owned companies, were not competitive in the wholesale market, and became a major financial burden for the off-takers who tried to repudiate or renegotiate the contracts.

In El Salvador, a 20-year PPA with a 144 MW diesel plant, signed by a SOE before the sector was reformed, went to international settlement after the off-taker claimed that the contract price was about 33 percent over the market price. In Honduras, PPAs signed in 2004 under favorable conditions[4] with efficient MSDs, came under political pressure for renegotiation two years later, when the contract price increased by 50 percent (the price of residual oil doubled in this period) and the government did not allow a pass-through of this increase to tariffs.

Difficulties in Ensuring Sufficient Generation Capacity

For different reasons, many markets in LCR have experienced difficulties in ensuring sufficient generation capacity to meet demand. One important objective of the design of any competitive wholesale market is to provide long-term price signals for expanding supply and ensuring sufficient generation capacity. Keeping the lights on is a high priority for any government because energy shortages threaten its political survival. In theory, the energy price in an ideal competitive spot market meets this requirement. In practice, the operation of a spot market is constrained by a set of interventions: spot prices are subject to price caps, measures taken to control market power weaken the price signal, and demand does not participate actively in the market. Often, some regulatory interventions tried to compensate for the constraints of the market; such as capacity charges, and capacity markets and obligations to enter into long-term contracts to meet demand (Table 1.11) (Millán, 2006).

Chile experienced repeated power outages during the summer of 1998-99 and introduced new regulatory measures in the wholesale market. Although one of the main reasons was

[4] Capacity payments of US$12/kW per month when other PPAs with diesel plants in the region were charging about US$18/kW per month.

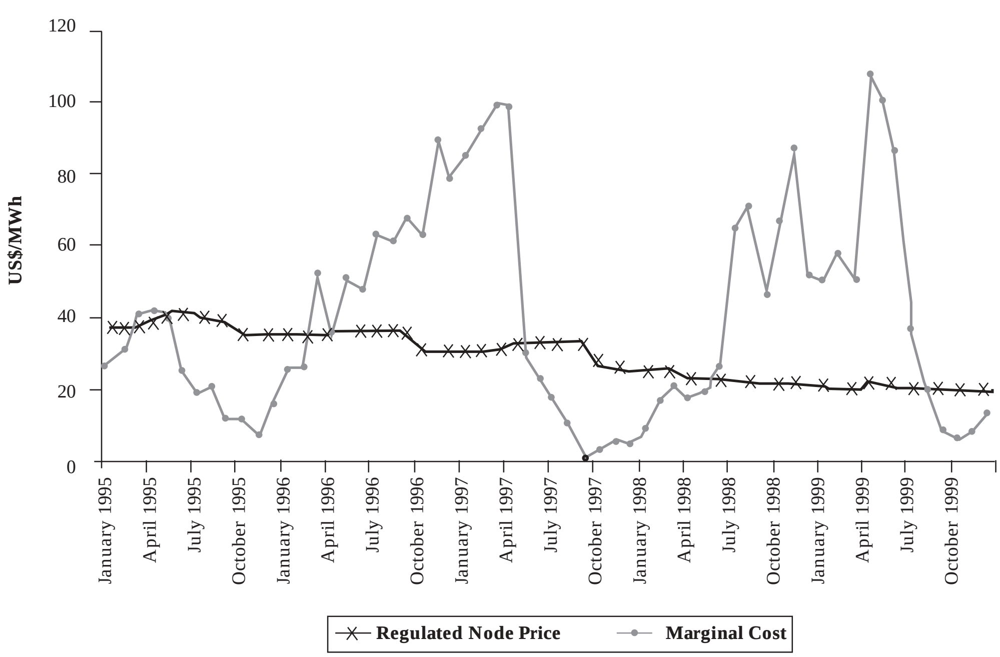
Table 1.11: Regulatory Interventions to Ensure Sufficient Capacity

	Capacity Charges	*Capacity Markets*	*Obligation to Contract*
Initial Reform	Argentina, Bolivia, Chile, Colombia, Dominican Republic, Peru	Guatemala, Nicaragua, Panama	Brazil, Dominican Republic, Guatemala, Nicaragua, Panama
Second-generation Reform	Colombia (new rules)		Brazil (new rules), Chile, El Salvador

Source: Authors´ calculations.

the vulnerability of a hydro-based generation system due to the worst drought in 40 years, it was clear that the price-setting mechanism used to calculate node prices (expected value of future marginal costs) did not provide incentives to develop a long-term contract market between generators and Discoms, and that the prices seen by regulated consumers (node prices) were totally out of line with short-run marginal costs. In the middle of the 1998-99 energy crisis, the energy node price was decreasing and reached US$20 / mega watt(s) per hour (MWh), while the spot prices peaked at US$100 / MWh (Figure 1.14) (Pollitt, 2004; Tubino, 2004). This crisis, combined with other problems of the market rules, prompted adjustments of the electricity law in 2004-05 (*Ley Corta* I and II), which established, among other things, the obligation of Discoms to enter into long-term energy supply contracts based on competitive bidding procedures.

Figure 1.14: Chile – Wholesale Energy Prices 1995-99



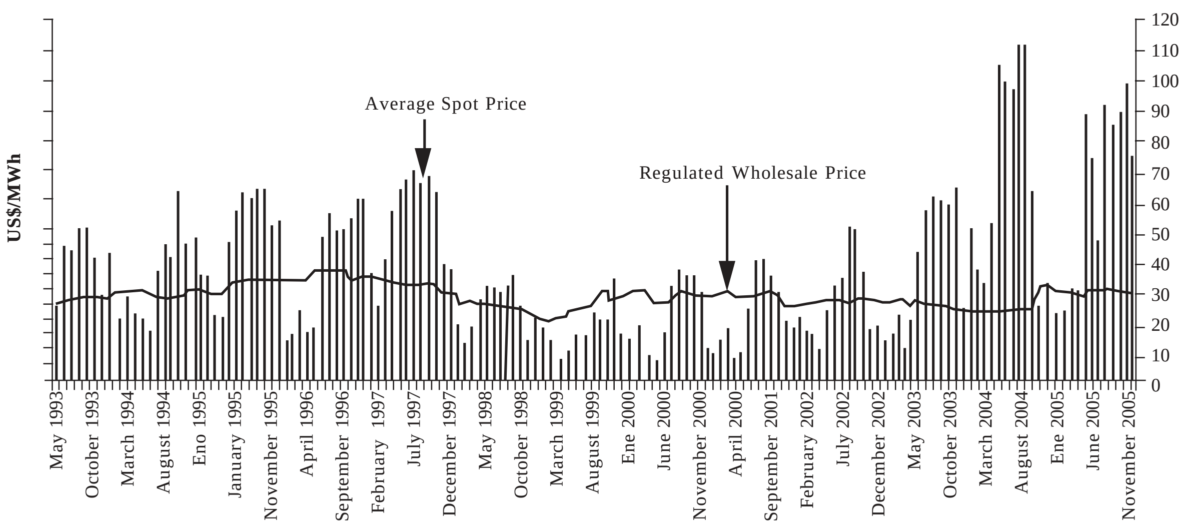
Source: CDEC, CNE data in Web page.

In Peru, a State-owned hydro generator had to support the energy contract market when private generators did not have incentives to sell energy under contract. Peru uses the Chilean model for calculating node prices. During the dry season of 2004, the spot price increased from US$20 to 100 / MWh, while regulated node prices remained at about US$25 / MWh. The generators, which sell energy to Discoms for the regulated market at the node prices, were not willing to extend the energy supply contracts and Electroperú, a State-owned generator, had to provide contracts to some Discoms (Tubino, 2004) (Figure 1.15).

Brazil had to curtail power demand in 2001 during the implementation of a new market-oriented reform and decided to change the market model and introduce new regulatory interventions. The energy crisis of 2001 in Brazil, which resulted in about 20 percent reduction of electricity demand, related to a severe drought in a hydro-based generation system, was also due to difficulties in attracting private capital to expand thermal generation capacity during the implementation of a new market model (uncertainties about the regulatory framework) and to flaws in the rules used to estimate firm generation from hydroelectric plants. Although the energy crisis was well managed by the government, reducing 20 percent of demand without disconnecting loads, it was a contributing factor to its political defeat in the presidential elections of 2002. The new government considered a return to a public sector model but, finally in 2004, a new law maintained the basic structure of the original market-oriented model, but introduced a quasi single-buyer model for the regulated market, based on periodic auctions managed by a new energy planning institute (Millán, 2006).

The difficulties of competitive markets in Colombia and El Salvador mentioned above, also illustrate the problem of ensuring sufficient generation capacity.

Figure 1.15: Peru – Wholesale Energy Prices



Source: Comité de Operación Económica del Sistema Interconectado Nacional (COES) data in Web page.

These difficulties and concerns are not unique to LCR nor to emerging economies. Many developed countries have adopted regulatory interventions to ensure sufficient capacity, particularly after the electricity supply crisis of 2001 in California. The eastern pools in the U.S. ensure generation adequacy by imposing an installed capacity obligation on load serving entities. Box 1.2 provides a note on the measures adopted in the European Union (EU) to ensure security of supply; a good illustration of the concerns in developed countries.

Box 1.2: European Union – Measures to Secure Electricity Supply (Excerpts) 16.1.2004

The process of market opening in the EU started at a time with, generally speaking, excess reserve capacity in the system. One of the consequences of market opening and the drive for more efficiency in the sector is a closure of this excess capacity. However, the costs to society of a shortage in the supply of electricity are much higher, as the electricity supply crisis in California has shown. In the peripheral markets of Ireland, Scandinavia, Italy, Greece and the Iberian Peninsula, a trend towards capacity insufficiency is visible at times. It is conceivable that generation inadequacy will develop in the core Union for the Co-ordination of Transmission of Electricity (UCTE) market as well, if no adequate measures should be taken.

The Commission believes that the internal market will, in general terms, provide the appropriate framework to ensure security of supply in electricity. However, in exceptional circumstances, additional measures may be necessary to achieve the right social outcome of securing supply at reasonable prices. A disproportionate welfare transfer from consumers to companies in the event of supply scarcity has to be avoided.

Security of supply in electricity is a public good and …. the Member States have to guarantee universal service at least for household consumers.

The provisions in the Directive on which Member States and the EU can base themselves to take any necessary measures, are the following: …

Recital 21-22

(21) Nearly all Member States have chosen to ensure competition in the electricity generation market through a transparent authorization procedure. However, Member States should ensure the possibility to contribute to security of supply through the launching of a tendering procedure or an equivalent procedure in the event that sufficient electricity generation capacity is not built on the basis of the authorization procedure.

Source: European Commission.

The main trend in regulatory interventions in LCR is to establish an obligation to contract the long-term supply of a major portion of expected demand of the regulated market using competitive bidding procedures, and to maintain a liberalized market for large consumers. The spot market continues to play the very important role of providing the energy price signal and to operate as a balance market. The use of long-term contracts as the main instrument for electricity trade meets several objectives: (i) hedge the price and quantity risks of a volatile spot market; (ii) facilitate the financing of new generation by providing more certainty in the cash flow of the projects; and (iii) mitigate the impact of market power, reducing the incentives to manipulate spot prices. It is also easier to introduce competition in the contract market, even in small markets, provided that the bidding procedures and the market rules do not impose restrictions or barriers to the entry of new generators, and that the Discoms are creditworthy.

There are substantial differences between long-term contracts in a competitive wholesale market and the long-term PPAs used for the development of IPPs. While the PPAs are physical supply contracts with specific generation plants, used to facilitate project financing by insulating the private investor against market and fuel risks, long-term contracts are usually financial instruments used to hedge price and supply risks, as well as facilitate financing of new projects. Reconciling these two objectives is not easy unless the sources of generation are diversified so that energy prices in the wholesale market are less vulnerable to external shocks than the price of energy supplied from just one technology or energy source. Otherwise, in a thermal-based generation system, the volatility of spot prices is replaced by the volatility of fuel prices when most of the PPAs are long-term contracts with variable payments indexed to liquid fuel prices, or, in a hydro-based generation system, the price risk is replaced by a quantity risk in the event of severe droughts.

Low Access to Affordable Electricity Service in the Rural Areas

There is still a strong need to expand electrification in rural areas in LCR countries. While overall access to electricity has improved significantly over the last two decades, rural areas still lag behind. In 2005, about 50-65 million people in Latin America, mostly in rural and poor areas, did not have electricity service. This is particularly true in low and lower middle-income countries where electrification rates of rural areas are about 30 percent (Bolivia, Nicaragua and Honduras).

Power sector reform and the privatization of the electricity sector in LCR have been more successful in increasing access and providing service in high population density areas. In such urban, or semi-urban areas, costs (both capital and operating) per client are significantly lower, commercial risks can be better managed and potential returns are more attractive. By nature, therefore, the private sector is much less interested in rural zones and there are only limited examples of the private sector advancing electricity in rural areas. Constraints in fiscal space limited the resources available to electrify rural areas, while the new institutional settings in the power sector were not necessarily adequate, or prepared, to service effectively rural zones.

Rural electrification is not only directly linked with poverty reduction and economic development, but forms a necessary response to strong social pressures in client countries. Access to electricity is an essential element in improving quality of life, access to basic services such as a good education and health care and opportunities for economic development. In surveys of rural and marginalized urban communities, electrification is consistently indicated to be among the top five infrastructure priorities, usually immediately following roads and water supply.

Increasing electricity access to the poor requires intervention of the public sector. Electrification of rural and marginal urban communities almost always requires a subsidy on the cost of connection since high capital costs and relatively low usage levels make such investments unattractive financially if no subsidies are granted. This has been the case even in industrial countries such as the United States and Canada.

A mechanism to provide the necessary capital cost subsidies needs to be defined and, in some cases, funded by the public sector. This is especially important in countries in LCR with medium and low coverage, where the challenge is still large. There are various options for funding mechanisms including: (a) cross-subsidies from other customers in the sector (for example, Ecuador's explicit surcharge on large customers to finance the Fondo de Electrificación Rural y Urbana Marginal (FERUM) fund); (b) annual funding from the Treasury; and (c) financing from international agencies such as Japanese aid, Inter-American Development Bank (IADB) and the World Bank.

One of the most successful models for financing rural electrification is that of competition among Discom subprojects for capital cost subsidies, as used in Chile, Ecuador and El Salvador. Such a mechanism (which can be used whether Discoms are publicly owned as in Ecuador or privately-owned as in Chile and El Salvador), together with a reliable source of funding such as a surcharge could be considered a best-practice approach to rural electrification.

A major challenge exists in providing electricity services to remote populations, where extension of the grid would be prohibitively expensive. This challenge exists in all three groups of Latin American and the Caribbean (The World Bank regional vice presidency) countries. Many countries, such as Peru, have traditionally used isolated small hydro to serve remote rural communities. In recent years, Renewable Energy (RE) systems such as individual Solar Home Systems (SHS) have been increasingly used to serve rural populations in a cost-effective manner. Almost all LCR countries are beginning to explore this option. There are SHS promotional programs initiated by the public sector but involving the private sector in Argentina, Bolivia, Brazil, Chile and Mexico. As costs of SHS come down with the expected entry of new Chinese producers in the market, these systems are expected to become even more competitive.

Importance of Improving Institutional and Economic Governance

Governance is a broad concept, defined as the traditions by which authority in a country is exercised for the common good. Governance includes three main dimensions: political dimension (selection and replacement of governments), economic (ability of the government to manage its resources, and formulate and implement sound policies) and institutional (the respect of citizens and the State for the regulatory institutions, the stability and enforceability of contracts, the protection of property rights and transparency in the application of rules and regulations).

There is a growing recognition of the link between good governance and successful development, and between governance and private investment. Investors in the power sector in LCR give high priority to the stability and enforceability of laws and contracts, and the independence of the regulatory authority (institutional dimension), to attract and retain international investment. Firms in emerging economies consider that by far the largest constraints to do business in a country are bureaucracy and corruption. There is high correlation between country competitiveness and control of corruption (Kaufmann, 2005). The importance of governance has stimulated empirical research aimed at measuring governance and monitoring country progress.[5]

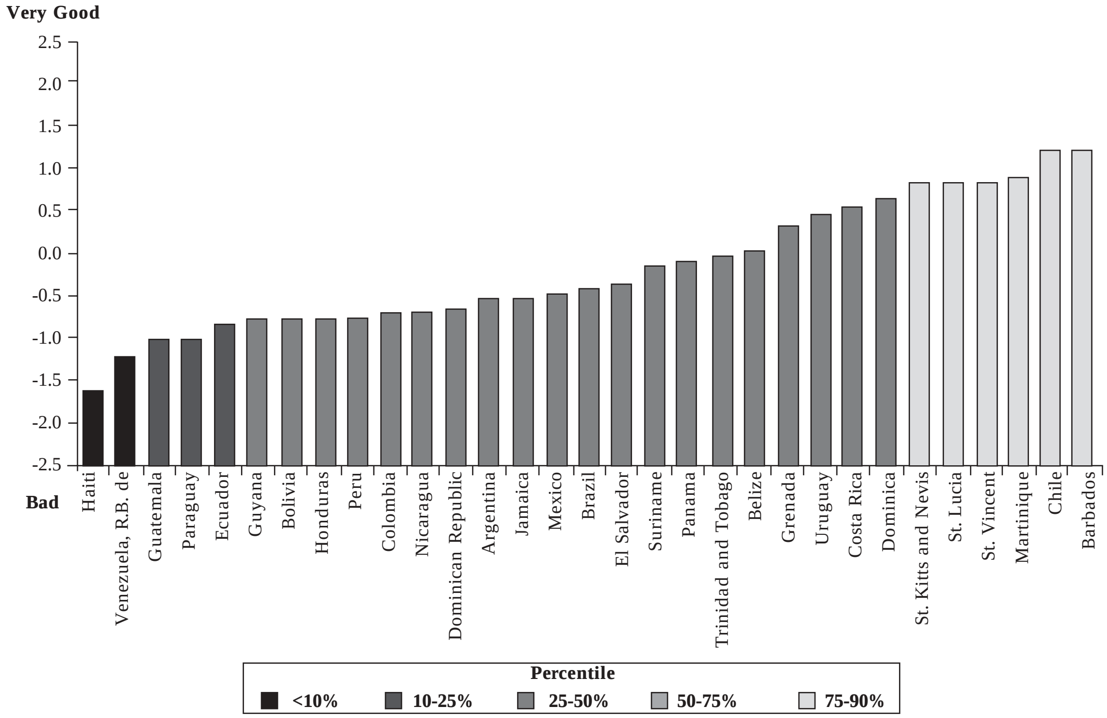
In spite of improvements in governance since 1996, many countries in LCR were still classified in 2005 in the two lower quartiles in key governance indicators (rule of law and control of corruption), as compared to developed countries and emerging countries in other regions. Most large countries in LCR were classified in the second quartile, and only Chile and some island States made it to the fourth quartile (Figure 1.16).

A recent study on the governance of electricity regulatory agencies in LCR concluded that there is an overall good regulatory governance level in the region in terms of both its design and its implementation (Andrés, 2007). Governance was assessed considering four factors: independence from political authorities and managerial autonomy; accountability both to other branches of government and to the public; transparency in the application of the rules and decision-making procedures; and the tools (instruments and mechanisms for revising tariffs, and monitoring the wholesale market and quality of service, information systems and auditing procedures).

However, the experience with power sector reforms in the region indicates that regulatory governance by itself is not enough to create commitment to the unbiased application of regulatory principles and rules, and to build legitimacy. The idea of creating an independent institution, whose decisions would be both transparent and independent of government political authorities, and delegating to it the regulation of competitive markets and natural monopolies based on the application of general tariff principles and market rules, did not

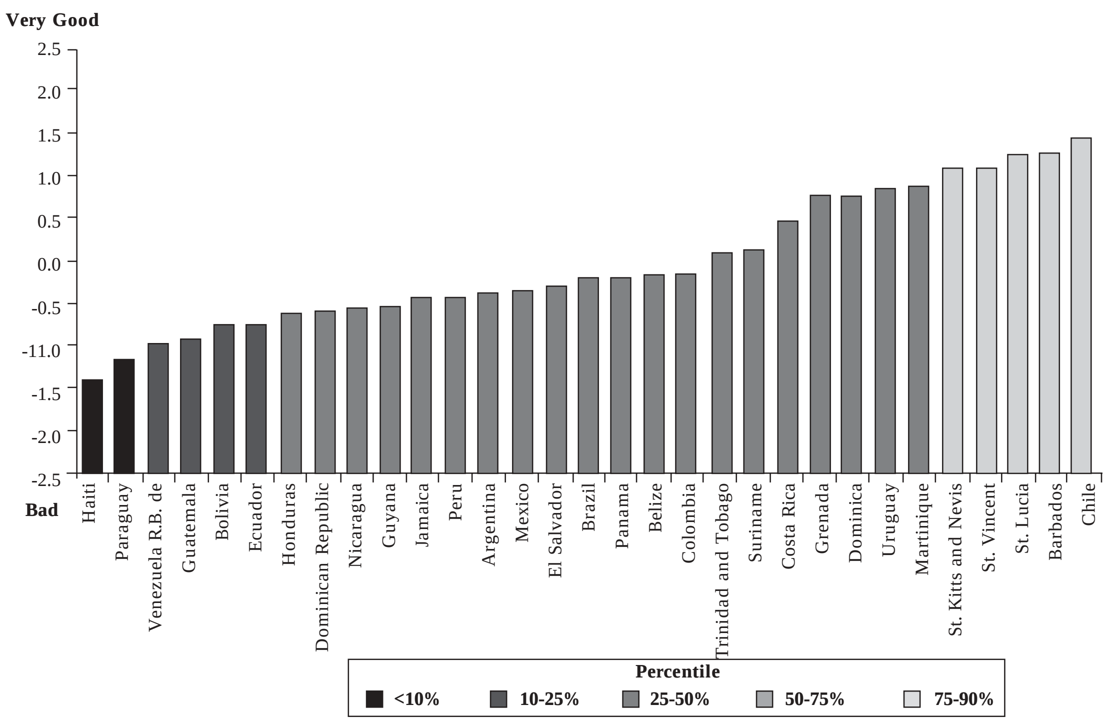
[5] The Worldwide Governance Indicators, a research project supported by the World Bank, have been compiled since 1996 and measure the quality of governance in well over 200 countries.

Figure 1.16A: Governance – Rule of Law Indicator – 2005



Source: The World Bank – Worldwide Governance Indicators Dataset 2005.

Figure 1.16B: Governance – Control of Corruption – 2005



Source: The World Bank – Worldwide Governance Indicators Dataset 2005.

work well in some countries in the region. This could be attributed to several reasons: (i) governments have interfered in the regulatory process, especially when their political survival is at risk (Argentina, the Dominican Republic, Nicaragua, Honduras and Guatemala); (ii) substantial autonomy is appropriate for countries with well-developed political and judicial systems, but not for countries with weak political and judicial commitments to transparent and fair application of regulations – the discretion in the application of general principles and rules by the regulator in many cases created uncertainty and instability, deterred private investment, and undermined credibility (case of Colombia); and (iii) total autonomy from government is neither feasible nor desirable (Brown, 2003).

Power sector reform intended to improve corporate governance (economic dimension) by the separation of roles of policy making, regulation and ownership; competition; and private participation in the provision of electricity services. In spite of the substantial improvements in corporate governance and performance of utilities, the problem persists. In many countries, SOEs maintain a substantial role as providers of electricity service and some have weak corporate governance that has undermined their performance and financial position: micromanagement and interference by the government to meet other social goals; diffused accountability for performance; some hold a monopoly position and are not subject to the discipline of a market; and their administration lacks operational autonomy.

LESSONS LEARNED

The assessment of power sector reform in LCR shows substantial progress in many countries in improving efficiency, quality of service and electricity access, and attracting private participation. It also shows that the market model implemented by the reforming countries experienced difficulties in recent years due to a combination of external shocks (economic and financial crisis, corporate scandals, power market failures in developed countries, severe droughts and high oil prices), and that the demand of the new market models for strong institutions, political commitment, technical capability and adequate market size and structure far exceeded the endowments and conditions of many countries in the region.

In spite of the difficulties that raised concern about the sustainability of reforms, the experience shows that power sector reform is not a one time event but a process subject to adjustments, corrections and, sometimes, setbacks. Although the threat of a counter reform was real in some countries, it appears that going back to a public sector model is no longer a valid option.

The assessment shows that most countries in the region face new problems and unresolved issues to meet future energy demand:

- Drop of private investment and flight of private investors;
- Dependency on oil imports for power generation and vulnerability to high oil prices, mainly in Central America and the Caribbean;

- Political opposition and dissatisfaction with privatization and liberalization policies. Unfortunately the financial and economic crises in the region in the early 2000s, that adversely affected the well-being of the people, were linked with these policies, creating a political backlash;

- The reform process in many countries is incomplete – the transition to cost-covering tariffs was not completed, the regulatory institutions are weak and lack credibility, and the market mechanisms have to be adjusted;

- The public sector still controls a substantial portion of generation and distribution and most of the transmission in many countries in the region. Lack of good governance and poor financial condition of SOEs is still a problem, and these companies have limited internal generation of funds to finance required investments; and

- The legitimacy of reform was undermined when the poor were not the main beneficiaries of the efficiency improvements.

There is a wealth of experience in the region and in other developing countries with the introduction of a market model, and many valuable lessons have been learnt in this process, that are discussed in the literature (Besant-Jones, 2006; Millán, 2006). We summarize a few lessons that are relevant to make adjustments in the market models and meet future energy demand:

- Technical competence and independence of regulatory institutions are essential to build legitimacy. Legitimacy can restrain political opportunism and improve the credibility of government commitments, in countries in the region with a tradition of clientelism and populism;

- Stability and enforcement of contracts and market rules, and protection of property rights are essential to attract and retain private investment in the sector;

- Governments have difficulties in keeping commitments when their political survival is at risk through large tariff increases or energy shortages;

- Private investors are reluctant to take the risks of competitive power markets in countries with weak regulation. To be sustainable, the financing models used to attract private investments should fit the country risks and political realities;

- There are difficulties in relying on competition and market signals to ensure sufficient generation capacity to meet demand. Obligation to enter into long-term contracts and other regulatory interventions are necessary in the region;

- Unbundling in small markets only makes sense when there is an opportunity to integrate into a larger regional market. Separation of accounts or business units may be sufficient to reveal cost information. Retail competition for small low-voltage consumers does not make sense even in developed countries; and

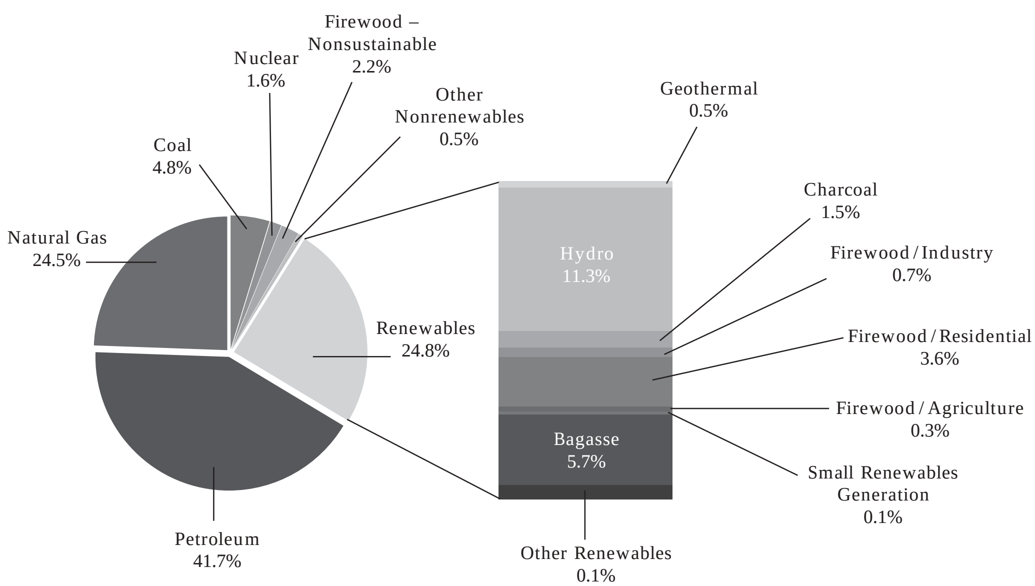
- Power service providers, regardless of private- or State-owned ownership, can only function commercially under a legal and political framework that supports cost recovery tariffs and penalizes theft and fraud.

As was discussed above, the reformers acknowledged the problems of first generation reforms and introduced some corrective measures: promote long-term contract markets to ensure sufficient supply, mitigate market power and facilitate private financing; independent supervision of market operation; and improve the transparency of the regulatory process. The World Bank also incorporated most of the lessons learnt in its operational policy.[6]

Renewable Energy

A general definition of RE includes energy generated from solar, wind, biomass, geothermal, hydropower and ocean resources, biofuels, and hydrogen derived from renewable resources. According to the energy matrix for LCR prepared by the Economic Commission for Latin America and the Caribbean (ECLAC), in 2004 RE contributed about 25 percent of the primary energy supply, of which 11 percent corresponds to hydroelectric power, 5.7 percent to bagasse and 4.6 percent to fuelwood (Figure 1.17). The sustainable development of renewable resources was promoted to address environmental concerns and has become a high priority in the region to help reduce the vulnerability to high and volatile oil prices, diversify the energy sources, increase access to modern energy services for the poor and meet increased demand, at least economic, financial and environmental costs.

Figure 1.17: Latin America and the Caribbean - 2004 - Energy Supply



Source: ECLAC.

[6] Source: ECLAC (2004), gas natural: natural gas; carbon: coal; lena no sost: non-sustainable firewood; otros no renovables: others non-renewables; Renovables: renewables; Petroleo: oil; hidroenergia: hydro energy; geotermal: geothermal; carbon de lena: charcoal

In this report, we limit the definition of RE to power generation from wind, small hydro, geothermal and biomass and to biofuels used in transportation. Small hydro refers to hydroelectric plants with a capacity of less than 20 MW, so that medium and large hydro plants are excluded.

LCR has a substantial potential of renewable resources. Latin American countries, rich in large hydroelectric resources, also have substantial small hydro potential. Many countries have areas with excellent wind conditions, with a wind power class equal or higher to four; high solar radiations of more than 5 kWh / square meter (m^2) are frequent in large areas of the Southern Cone, Mexico and the Caribbean; many countries are located in volcanic areas; and bagasse already contributes about 6 percent of the primary energy. The potential of renewable power in a selected group of countries exceeds 250,000 MW, which is about the same as the total conventional generation capacity in the region in 2005 (Table 1.13).

However, development of RE in the region is in the early stages and the information about resource assessment at a country level seems to be fragmentary and incomplete. In 2005, the installed capacity in renewable power of about 6,800 MW represented less than 3 percent of the total generation capacity in the region. Renewable power capacity was distributed 49 percent in biomass, 29 percent in hydro, 20 percent in geothermal and only 2 percent in wind (Table 1.12). The capacity in biomass and small hydro is underestimated as only a few countries report the installed capacity of bagasse-fired self-generation or discriminate small-hydro from large hydroelectric power. However, it is certain that only about 150 MW of wind power was in operation.

The scarce information available about resource assessment in the region confirms that there is a large and underdeveloped wind power and small-hydro potential. Brazil, Mexico and Colombia report more than 200 giga watt (GW) in wind power and 43 GW in small hydro. On the other hand, progress has been made in developing about 25 percent of the geothermal potential in Mexico and Central America (Table 1.13).

The development of the indigenous renewable resources in the region faces many barriers, similar to those encountered in other countries in the world during the early stages of development of these resources. Economic barriers like high capital costs, which mean higher financing requirements per kW installed; subsidies for conventional forms of energy and lack of fuel price risk assessment in expansion plans; and the failure to internalize all costs and benefits of energy production and use (environmental, security and diversification benefits). Regulatory barriers like the lack of a legal framework for IPPs, making it difficult for small renewable power developers to plan and finance projects on the basis of known and consistent rules; the difficulties of small projects to access energy markets based on complex rules and with high standards and costs of connection to and use of the transmission grid; restrictions on siting and construction; and in some countries power utilities that hold monopoly rights to supply electricity. Other barriers are the high transaction costs on a per kW basis due to its small size and lack of familiarity with the new technologies; the impact

Table 1.12: LCR – Renewable Generation Capacity End of 2005 (in MW)

	Wind	*Minihydro*	*Biomass*	*Geothermal*	***Total***
Southern Cone	58	1,277	3,294	0	**4,630**
Andean Countries	20	392	0	0	**412**
Central America	66	281	45	425	**817**
Mexico	2	0	0	960	**962**
Latin America	147	1,950	3,339	1,385	**6,821**

Source: Prepared by authors based on EIA´s data in Web page.

Table 1.13: LCR – Small Renewable Power Potential in Selected Countries

	Wind	*Minihydro*	*Geothermal*
Brazil a/	140,000	15,000	
Caribbean e/	170		150
Central America d/	8,500		3,000
Colombia c/	21,000	25,000	
Mexico b/	40,000	3,300	2,400

Source: a/ Plano Nacional de Energía 2030, EPE, 2006.
b/ Energía renovable para el desarrollo sustentable en México, 2006.
c/ Review of policy framework for increased reliance on RE in Colombia, 2006.
d/ Prospectiva Energética de América Latina y el Caribe, 2005.
e/ Energy in the Caribbean, general assessment, Dussan, 2006.

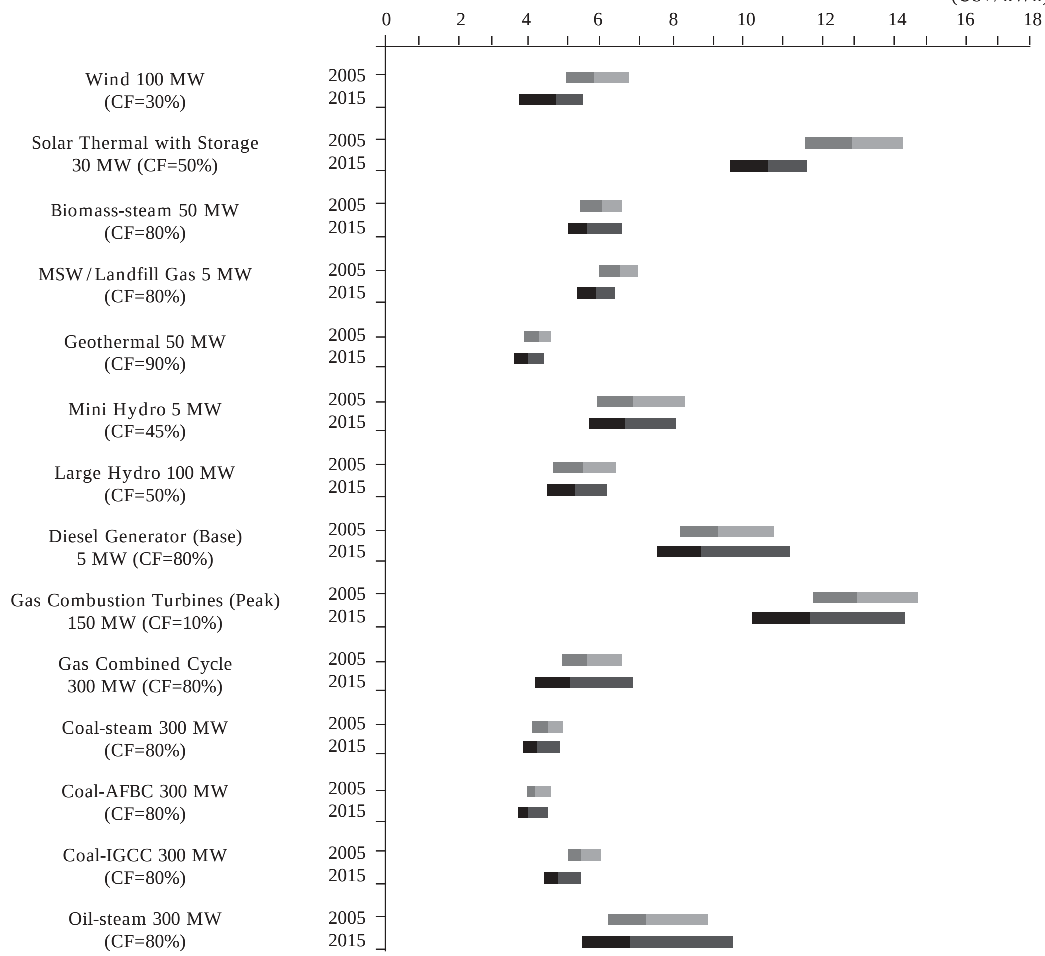
of intermittent sources of energy in power system operation and reserves; the lack of adequate financial instruments and lack of technical or commercial skills and information on the new technologies.

However, these barriers are being reduced. During the past 10 years, significant technological and market development has helped reduce the capital costs of wind power by half, to reach competitive levels of about US$1,400/kW in 2005; and due to recent high oil prices and energy security and global climate change concerns, development of indigenous renewable resources is at the top of the agenda of many countries, which have adopted policies to facilitate the development of RE in both on-grid and off-grid installations.

In a scenario of high oil prices, renewable power appears to be competitive with conventional generation. A study of levelized energy generation costs for on-grid renewable power and conventional generation recently published by the World Bank (the World Bank, 2006c) shows that renewable power may be competitive on an energy basis[7] with oil-fired conventional thermal generation and with some large hydro generation. Renewables would be more competitive by 2015, taking into account the technological development and declined capital cost of new technologies (Figure 1.18).

[7] If firm capacity is valued, the energy costs of renewables with low plant factor and intermittent output like wind and run-of-river hydro, are not comparable with firm power of conventional thermal generation.

Figure 1.18: Grid Connected Forecast Capital Cost



Source: The World Bank, 2006c.

There is a consensus about the need for long-term energy policies that provide incentives to improve the efficiency, reduce the cost and develop a sustainable RE industry. The objective is not to install RE generation capacity at any cost but to establish adequate conditions for a sustained development of RE. The main policy instruments to promote the development of on-grid RE are: regulatory frameworks that facilitate access to generation markets; financing assistance and fiscal incentives; technical norms and quality standards; and information dissemination.

Access to electricity markets. Two schemes have been used to facilitate access to generation markets of on-grid projects: feed-in prices and quotas. In the pricing system, the regulatory framework establishes a price at which the public utility has the obligation to buy energy from RE projects, and the investors define the generation capacity that they are willing to develop at that price. In the quota system, the regulations determine a target quota for the participation of RE projects in the generation market and the feed-in price is determined by competitive bidding procedures.

Financial and fiscal incentives. The fiscal incentives frequently used in developed countries to promote RE are tax credits for investment and production, and exemptions on Value Added Taxes (VAT) and import duties. Tax holidays are also used as an incentive. Frequently, the subsidies are financed by a surcharge on electricity tariffs. As a complement, many governments establish funds that provide long-term credits at preferential rates. Probably the most important financial incentive for the development of RE is the elimination of subsidies to conventional sources, meaning that the energy prices for these sources should reflect real fuel costs, including environmental costs.

Norms and quality standards. This includes norms and standards on equipment, on the project site, the grid code (norms and conditions for the connection and use of the electric power grid) and the construction code. Construction and operation standards are useful to avoid the use of inferior or inadequate technology that have a negative impact on the quality of supply service and that may ruin the reputation of new technologies. Open access to transmission grids and fair transmission charges are important policy instruments to facilitate the development of RE in competitive wholesale power markets.

Information dissemination. Information dissemination includes assessments of the potential of RE resources, education and training on new technologies, databases on RE energy information, and information on incentives and procedures for the development of RE resources. Public consultation and participation of stakeholders in the process of formulating policies and planning of RE resources are also important to generate wide public support for the new technologies.

Many countries in the region adopted legislation that provides incentives and targets for the development of on-grid renewable power, mainly in response to environmental concerns, particularly the risk of drastic climate change as a result of the emission of Greenhouse Gases (GHGs) by power generation based on fossil fuels. Development of renewable power has become a priority in some countries to reduce the reliance on imported fuels and help in the diversification of energy sources. Table 1.14 summarizes some of the incentives used in LCR for the development of on-grid renewable power. In 2002, the Brazilian government introduced the Proinfa: Programa de Incentivos a las Fuentes Alternativas de Energía Eléctrica (PROINFA) program to stimulate the development of biomass, wind and small hydro generation, based on a quota system. Its initial target was to implement 3,300 MW of projects by the end of 2006; the second phase aims at achieving a share of 10 percent of alternative renewable sources for electricity production in the next 20 years. Power from renewable generators is bought by Electrobrás based on 20-year PPAs, with a guaranteed purchase price and project financing available through the Brazilian National Development Bank (BNDES). The first call for projects attracted enough projects to generate 6,600 MW, but did not achieve the 1,100 MW quota allocated for biomass.

Costa Rica introduced a feed-in price system (avoided costs) in a 1990 Law that promoted the development of small renewable IPP projects by the private sector, based on 20-year PPA with the vertically integrated monopoly. The program has been effective in increasing the participation of renewable IPPs to 12 percent of the installed capacity in 2005, although it has been argued that the energy prices paid to IPPs were set above the avoided costs to facilitate financing of these projects. The participation of RE increases to about 25 percent if other renewable projects that were developed by the public utility are included.

Table 1.14: Renewable Power Incentives Used in LCR

Countries	*Incentives for Renewable*
Argentina	US$0.01 per kWh subsidy. Tax exemptions. Benefits for loans US$0.005-0.01 subsidies at provincial level. Research and Development (R&D) investment
Brazil	PROINFA established quotas for small hydro, wind and biomass supported by long-term PPAs at base prices. Special financing mechanisms. Ten percent market share target in 20 years
Colombia	Tax breaks for generation from alternative energies for 15 years (given producers hold carbon emission certificates and invest 50 percent of the certificates in social infrastructure projects)
Costa Rica	Long-term PPAs at avoided cost for generation from renewables. No import taxes on equipment
Dominican Republic	Tax breaks on equipment imports (15 years) Taxes on fossil fuels with the aim of creating a fund to promote alternative energy and programs to reduce total energy consumption by 5 percent
Ecuador	Feed-in price for generation plants that use nonconventional energy sources
Honduras	Long-term PPAs at avoided costs plus 10 percent price premium. Tax breaks: exemption of sales taxes during construction and import duties and five-year corporate tax holidays
Mexico	Discounts of between 50 and 70 percent on the transmission and connection costs for renewables. New renewable bill is being processed

Source: Expansion of Table in Energy Sector Management Assistance Program (ESMAP), 2006.

Honduras established, in the late 90s, a feed-in price system for renewable IPPs, based on avoided costs plus a 10 percent premium, long-term PPAs with the vertically integrated monopoly and fiscal incentives. As of 2005, the participation of renewable IPPs in operation and construction has increased to about 6 percent of the total installed capacity.

In Mexico, an anticipated RE promotion law Ley para el aprovechamiento de las fuentes renovables (LAFRE) was sanctioned by one chamber of the national congress in 2005, and passage was expected in 2006. The Law aimed at establishing a program with a target for renewable power (excluding large hydro) to supply 8 percent of the national electricity production by 2012. The Law also provides for the creation of a trust to support RE projects, accelerated depreciation and net metering.

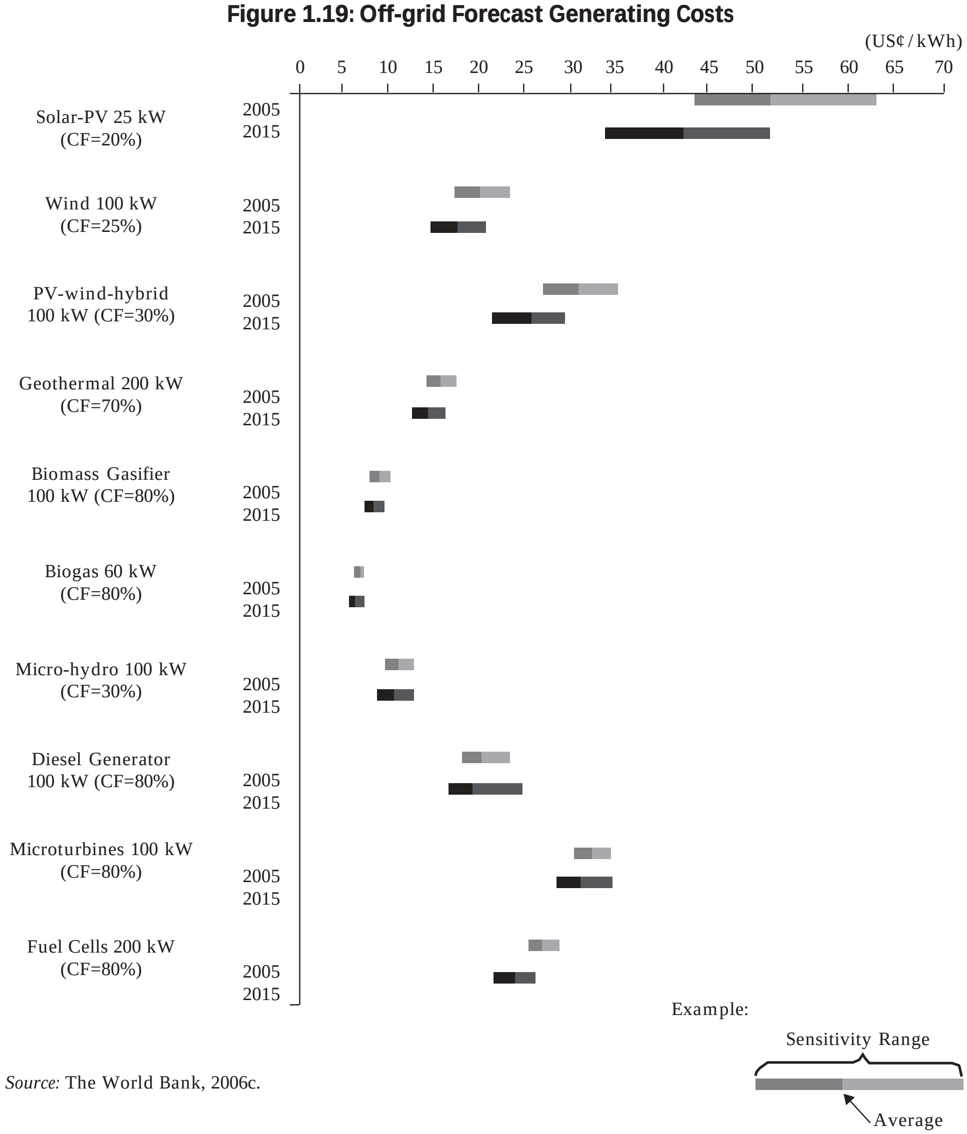
OFF-GRID RENEWABLE GENERATION

Although the levelized cost of off-grid renewable generation options (in isolated mini-grids) may be from three to five times higher than the cost of on-grid options (Figure 1.19), RE is still an economic solution for energy supply to sparsely populated rural areas where connection to the public grid is not a technical option or is too expensive.

Several programs are being implemented in the region to promote off-grid rural electrification programs based on renewables. In Brazil, these programs started back in 1992-93 through pilot projects in cooperation with the German and U.S. governments. Around 1,500 SHS were installed with the participation of local electricity Discoms in several states. The Brazilian government launched two new initiatives in 1994, the first to develop the Brazilian Program for the Dissemination of Renewable Energies, which included the creation of a Reference Center called Centro de Referência para as Energias Solar e Eólica Sérgio de Salvo Brito (CRESESB), for the dissemination of information on solar and wind technologies.

In a second initiative, the Brazilian government established the Programa para o Desenvolvimento da Energia nos Estados e Municípios (Program for Energy Development of States and Municipalities) – PRODEEM. This program has been coordinated by the Ministry of Mines and Energy to deliver electricity to rural communities not served by the grid, by means of locally available RE resources. Several states, including Minas Gerais, Sao Paulo y Paraná, followed suit and created their own photovoltaic rural electrification programs.

Figure 1.19: Off-grid Forecast Generating Costs



Source: The World Bank, 2006c.

PAEPRA was launched in 1994 by the Ministry of Energy. The goal of this program is the supply of electricity to 1.4 million people and to around 6,000 public services in remote areas of low population density, where supply from the grid is too costly. The World Bank and Global Environment Facility (GEF) approved a US$30 million (mn) loan and US$10 mn grant in 1999 to implement the Proyecto de Energía Renovable en el Mercado Eléctrico Local (PERMER) project as a component of PAEPRA in eight participant provinces. Off-grid electricity services for about 3,000 households and schools have been installed and about 3,500 photovoltaic equipment are being installed.

In Mexico, a massive use of renewables for off-grid rural electrification started in 1989, as part of a larger poverty alleviation program called Programa Nacional de Solidaridad (PRONASOL). Government-financed projects coexist with private sales. A total of around 90,000 SHS and hundreds of other systems for a variety of applications such as water pumping, including several mini-grids powered by solar-wind hybrids, are estimated to have been installed.

In Bolivia**,** the National Rural Electrification Program (PRONER) was created to promote and support economic development to improve living conditions in rural areas. The goal is to provide 100,000 households with basic electricity services within five years. The first phase of the program will be carried out by the Bolivian government with financial support from the United Nations Development Programme (UNDP)/GEF. Its main objective is to remove financial, institutional and technical barriers to assure the successful application of renewables in rural areas.

Biofuels

Brazil is the world leader in production of bioethanol as a transportation fuel. Between 1975 and 2004, the ethanol program in Brazil substituted about 1,500 mn barrels (bbl) of gasoline. Ethanol from sugarcane in Brazil is arguably the first renewable fuel to be cost-competitive with a petroleum fuel for transport. Sugarcane accounts for 58 to 65 percent of the total cost of ethanol production, making efficient and low-cost production of sugarcane essential. The factors contributing to Brazil’s competitiveness include its natural endowments (climatic, topographical and soil conditions), an effective industry structure, active research and development (facilitated by the size of the industry), concerted efforts to endure the industry’s sustainability, and development of managerial skills to optimize inputs and processing. Nonetheless, Brazil’s growing biofuel industry is not without its problems or its critics. One problem is that land is used to produce fuel instead of food crops. Replacing biofuels for fossil fuels could put increased pressure on forests because of the land demand for biofuel crops. Depending on how this is managed, the balance of carbon-emission reductions might be positive, neutral, or even negative.

Blending of ethanol with gasoline is mandatory in Brazil, and the percentage has varied from 20 to 26 percent in recent years. The government offers a large tax break in favor of hydrous ethanol over the gasoline / anhydrous ethanol blend, imposes an import duty on ethanol with exceptions, and provides tax breaks to flex-fuel vehicles and hydrous ethanol-operated vehicles. Thirty-three percent of all the fuel used in Brazil's cars is now produced from sugar. More than 70 percent of all cars sold in Brazil in December 2005 can run on ethanol made from sugarcane.

Other South American nations are also getting on board. Most are embracing mandatory fuel mixes for cost, security and environmental reasons. The government of Colombia passed a law requiring a 10 percent ethanol mix in cities with populations over 500,000 starting 2006. In January 2006, Colombia began to mix gasoline with 10 percent ethanol produced from sugarcane, and the plan is to gradually increase the proportion until it reaches 25 percent in 20 years. As of October 2006, five mills produce 1 mn liter (l) a day of ethanol, but output should increase shortly by 0.5 mn l. Some 200,000 hectares (ha) are currently planted with sugarcane, 50,000 of which go toward the production of ethanol. Ethanol is exempted from tax on gasoline, and there is a 10-year tax holiday on crops and a tax exemption on biodiesel.

Some Central American countries, notably Guatemala and Costa Rica, have also proposed a mandatory gasohol programs. The Dominican Republic will require E15 and B2 (2 percent of biodiesel) by 2015. In addition, a regional association on renewable fuels of Central America was established to promote the industry in recognition of the importance of sector policy and management. A study by ECLAC on the prospects and implications of development of a bioethanol program in Central America showed that the impact of developing a gasohol program is small – a 10 percent ethanol blend would require an expansion of cane production by 7.7 percent or 31,300 ha without affecting sugar production. The productivity of the sugar industry in Guatemala, Costa Rica and El Salvador is already comparable to that in Brazil. As in other countries, regulatory support is vital to the initial development of the bioethanol industry.

Venezuela now mandates ethanol blending in some parts of the country, and may require a 10 percent mix nationwide in the future. Argentina has become the world's 17th largest ethanol maker, producing 42 million gallons last year (though its output goes mainly to agrochemicals, drinks and cosmetics). In Bolivia, 15 distilleries, are being constructed and the government is considering authorizing blends of E25 (25 percent of ethanol). Mexico, Paraguay and Peru are all considering biofuel programs as well. Many of these countries have learned from the experience of Brazil.

Energy Efficiency

There is ample room for improving EE in the region. After maintaining a downward trend in the 70s along with rapid economic growth, energy intensity in LCR has fluctuated between 6,800 and 7,200 British thermal unit (BTU) / US$ (2000) during the past 15 years, but with an upward trend, in part due to the economic recessions in large countries during the 90s and early 2000s (Figure 1.20). Meanwhile, the average worldwide energy intensity decreased 1.5 percent per year from 1980 to 2000.

The implementation of EE projects in the region has faced similar barriers as in developed countries: electricity tariffs do not reflect real economic costs; lack of information on potential energy savings and benefits; limited capability in providing EE services (how to structure, finance and implement energy savings initiatives by Energy Service Companies (Escos); and lack of experience in the financing of EE projects.

Many countries in the region have implemented EE programs (Table 1.15) aimed to reduce these barriers, which usually include the following components: adoption of policies and regulations to promote EE; dissemination of information about best practices; labeling and efficiency standards for electrical appliances and equipment; adoption of energy-efficient construction standards; creation of special funds to finance EE audits and projects; supply of high-efficiency fluorescent light bulbs; creation of specialized energy saving units in power utilities; and use of solar water heaters.

Mexico has achieved considerable energy savings with the implementation of several EE programs: the National Commission for Energy Conservation (La Comisión Nacional para el Ahorro de Energía – CONAE) has established 18 EE norms that apply to about 40 mn electrical equipment in operation; the Electricity Conservation Trust Fund (Fideicomiso para el Ahorro de Energía Electrica – FIDE) finances EE programs for large and small industrial and commercial consumers and the rehabilitation of electrical pumps used in irrigation systems; the Electricity Conservation Program (CFE-PAESE) promotes improvements in EE in the installations of public utilities; the Integral and Systematic Conservation Program (ASI) finances improvement in thermal insulation of houses, labeling of electrical appliances and information dissemination to residential consumers; and a daylight saving time program. The Secretary of Energy claims that these programs resulted in energy savings of about 20,000 giga watt (s) per hour (GWh) in 2005, equivalent to 4,900 MW (about 14 percent of peak demand), and is projecting about 10,000 MW in peak savings by 2014 (Prospectiva del Sector Eléctrico [SENER] 2005-14).

Brazil also has substantial experience in the execution of EE programs. In 1994, the government created the Brazilian Labeling Program (PBE), coordinated by the National Institute of Metrology,

Figure 1.20: LCR – Energy Intensity

Sources: Prepared by authors based on EIA´s data in Web page.

Table 1.15: Energy Efficiency Program in LCR

Country Program	*Run/Financed by Period*	*Main Priorities and Achievements*	*Specific EE Legislation*
Argentina: 1. Rational Energy Use Program (URE)	Energy Secretariat, National Office for Efficient Energy Use/European Commission 1992-99	Institutional Development EE and Energy Management in Industry Demonstration Projects in the Areas of Municipal Lighting and Urban Transport	Energy Efficiency Bill was Proposed in 1999
Brazil National Program for Energy Conservation (PROCEL)	Electrobrás/Government Funds/International Donors since 1985	Voluntary Labeling Program for Domestic Appliances and Electric Motors Education and Training in Public Services	Law 9991 of July 2000; Law 10295 of October 2001 on National Policy for the Conservation and Rational Use of Energy
Chile Energy Conservation and Rational Use Program (CUREN)	National Energy Commission (CNE)/European Commission 1992-97	Energy Audits and Pre-investment Studies in Industry and Commerce; Municipal Lighting; Public Information Campaigns; Energy Certification Standards; Voluntary Standards for Electrical Appliances and Industrial Plants	No
Colombia Program for the Rational and Efficient Use of Energy (PROURE)	Ministry of Mines and Energy, Mining, Energy Planning Unit (UPME)	EE Standards and Labeling	Law 697 of October 2001: Promotion of Rational and Efficient Use and Renewable Energy Sources
Costa Rica National Energy Conservation Program (PRONACE)	Ministry of Environment and Energy, Sectoral Energy Office (DSE). Since 1994	Education and Information Program to Improve the EE of Equipment, Compulsory Energy Labeling, Compulsory EE Program for Large Users	Law 7447 of December 1994: Regulation of Rational Energy Use
Ecuador Energy Saving Program (PAE)	Ministry of Energy and Mines, Alternative Energy Office (DEA)	EE Campaigns Standards and Labeling Education and Awareness Measures	
Mexico 1. Programs run by: National Commission for Energy Conservation (CONAE)	Ministry of Energy since 1989 GEF Funds to Promote Efficient Lighting	Minimum EE Standards for a Wide Range of Appliances and Equipment EE Programs in Different Sectors of the Economy and the Public Administration	
2. Electricity Conservation Trust Fund (FIDE)	(Comisión Federal de Electricidad – CFE) since 1990	Cofinancing IDB since 1998 Public Information, Education and Training; Energy Audits and Technical Assistance; FIDE Seal of Approval for Appliances	
Peru Energy Saving Project (PAE)	Ministry of Energy and Mines, in Coordination with Ministry of Education	Emergency Energy Conservation Campaigns: National Campaign 1994-96. Replacement of 750,000 Incandescent Lamps with Compact Fluorescent Lamps (CFLs) EE standards for appliances	Law 27345 of September 2000 Concerning the Promotion of Efficient Energy Use

Source: Reproduced from World Bank calculations.

Standardization and Industrial Quality (INMETRO) and, in 1985, it created the National Program for Energy Conservation (PROCEL) coordinated by Electrobrás. The EE programs received a boost with the enactment of key legislations, and adjustments of electricity tariffs to reflect costs in the 90s and the early 2000s,[8] and increases in international oil prices in the 2000s. The energy rationing of 2001-02 revealed a large potential for reducing electricity consumption in residential, industrial and commercial sectors without having a significant impact on output or comfort. The Ministry of Mines and Energy estimates that EE programs saved, on average, about 2,100 GWh / year or about 0.8 percent of electricity demand. Brazil's energy planning agency, Empresa de Pesquisas Eletricas (EPE), estimates a saving potential of about 8 percent of demand for 2006-16.

Oil and Gas Sector

Oil and Gas Sector Developments in LCR in the Past 10 Years

CHALLENGES AND BACKGROUND

The major challenge in assessing the impacts and outcomes of the reform program, supported by the World Bank Group in the oil and gas sector in LCR in the 90s, is the dearth of sector review work and literature on the lessons learned. This is in stark contrast with the comprehensive review literature that has been produced and sponsored by the World Bank Group and Energy Sector Management Assistance Program (ESMAP) on the successes and failures of the reform program in the power sector, at both LCR and global levels. This reveals the low priority the World Bank placed on the oil and gas sector in the past decade, which was reflected in the low level of lending operations and advisory work undertaken in LCR. If this knowledge and operational base continues to deteriorate, the capacity of the World Bank on matters pertaining to oil and gas in LCR would be eroded and, with it, the institution's credibility in the overall energy sector.

The last two decades have witnessed major changes in the international oil market, and in oil prices. There were three distinct phases. The first, from 1986-89 was characterized by low prices ranging for West Texas Intermediate (WTI) from US$15-19 / bbl and, represented the end of the long slow decline in prices from their peak in 1980-81, at the height of the first Gulf War. This was followed by a second phase from 1991-97 in which there was a relative price stability as it fluctuated between US$18-22 / bbl, only to decline to US$15 / bbl in 1998. The third and current phase from 1999-2006 witnessed a 50 percent increase in prices between 1999-2003 from US$20 / bbl to US$30 / bbl, followed by a further 150 percent increase by mid-2006.

The underlying factors driving this behavior of oil prices are varied and range, among others, from real and perceived global political crises; economic slowdown or recession in the major economies; increasing demand for oil in the rapidly growing Asian markets;

[8] Agencia Nacional de Energía Elétrica (ANEEL) created, in 1998, a program that required electricity utilities to invest 1 percent of billing in EE. Law No. 10.295 of 2001 determined that technical groups would establish limits to the specific energy consumption of electrical equipment manufactured or distributed in Brazil. Law No. 10.847 authorized the new planning agency (EPE) to promote energy conservation programs.

capacity and conversion constraints at the refinery level, particularly given the more stringent petroleum product specifications being called for; and limited growth in crude oil supply capacity globally to keep tandem with growing demand. What is important to recall continually is that, like in the past, oil will continue to undergo fluctuations in price in the future. This is highly relevant when policies and strategies to diversify away from petroleum product use are being formulated, and the projects that implement these visions are being evaluated and appraised. The key issue always to be confronted is: what is the oil price level that makes the diversification strategy a high-risk one.

The 90s was the most propitious period for launching privatization and governance programs in the energy sector. The former Soviet Union had collapsed and, with it, the economic model that advocated the “commanding heights” role of the State and its institutions. As noted above, from their nadir in 1986 of some US$11 / bbl, oil prices recovered modestly over the next few years to more viable levels, but remained relatively stable between US$18-22 / bbl throughout the 90s, other than the collapse to US$15 / bbl in 1998. In this environment, reform and privatization programs in the energy sector were undertaken in several countries in LCR, some of which were implemented with enthusiasm, given the recognition that increased reliance on markets was a more efficient way to manage the sector. However, the results of the reforms have been varied, since they require sustained political commitment and, that the economic and social benefits of the reforms have been able to win the support of a wide cross-section of the society.

THE REFORM PROGRAM AND THE ROLES OF THE PRIVATE AND STATE SECTORS

Countries possessing prospective petroleum basins have sought traditionally to increase investments in exploration and development. During periods of low oil prices, which prevailed in the 90s, the general policy was increased reliance on markets as the most efficient approach to manage the sector; and, therefore, reform and privatization programs were carried out in several countries. In the current environment of high oil and gas prices, the enthusiasm for privatization of State entities appears to be waning. This is giving rise to a more pragmatic approach which may hopefully yield more sustainable results.

In Argentina and Bolivia, both State oil and gas companies – Yacimientos Petrolíferos Fiscales (YPF) and Yacimientos Petrolíferos Fiscales Bolivianos (YPFB), respectively – were privatized. However, the economic crisis in Argentina at the beginning of the present decade, and the accompanying social and economic dislocation, created a dire situation. Artificially low oil and gas prices accelerated demand, and the lack of resources to invest resulted in the country being unable to meet either internal gas demand or its export gas commitments to Chile, resulting in severe rationing. This represented a setback to efforts to deepen and expand cross-border gas trade and highlights the importance of a period to rebuild confidence and trust in such trade. This is critical if competitively priced gas is to continue to play a key role in addressing climate change issues; reducing dependence on high-cost volatile imported oil; and resurrecting the belief that cross-border gas trade can enhance energy security in the Southern Cone. To compound these developments, in 2004, the government created a new

State-owned company (Empresa Nacional de Energía S.A.– ENARSA) for the production and sale of oil, gas and electricity, in sectors which had been privatized a decade earlier.

In Bolivia, the recent nationalization of the assets of foreign oil companies and the re-emergence of the State-owned YPFB illustrates, once more, the fragility of reforms in certain social and political settings. Additionally, these developments have raised questions about the scale of International Oil Company (IOC) operations in the country, and where the investment resources for the sector are to come from.

In contrast, the approach to reform and liberalization followed in Brazil, Colombia and Peru was more pragmatic, and may yield more sustainable results. In these cases, there was a successful separation of the institutional, contractual and regulatory roles of the State from the investment, production and commercial responsibilities of the State oil company. This has resulted in both private and State-owned companies expanding their operations and investing in new projects. In these three countries, the State companies have to compete for exploration acreage with private operators. The result has been positive. The number of contracts signed over the past two years by the State regulatory oil and gas agencies has increased significantly, as have the commitments to exploratory work. However, based on past results, though these countries do not possess the most prospective sedimentary basins, they have still been able to attract foreign private partners which augurs well for the sustainability of the reforms.

At the corporate level, the success of Petrobras is important. The company has achieved a high level of technical expertise and, in deep offshore technology, can stand shoulder to shoulder with the leading IOCs. It has increased oil and gas production significantly and, in the near future, Brazil is expected to achieve oil self-sufficiency. Additionally, the company's shares were placed on the market, with government retaining a 51 percent position. This last measure has enhanced not only corporate accountability, but contributed to capital market development by beginning to make available to the Brazilian investor access to one of the country's key sectors.

As shown in Table 1.16, only six (Argentina, Brazil, Colombia, Peru, Paraguay and Trinidad and Tobago) of the nine significant LCR oil- and gas-producing countries have independent regulatory institutions that award upstream contracts for Exploration and Production (E&P). In this context, what is important is that Brazil, Colombia, Peru, and Trinidad and Tobago are four of these countries in which considerable success has been achieved in attracting investment from private operators in E&P projects. This illustrates the effectiveness of the separation of the contractual and regulatory functions of the State from the commercial and production responsibilities of the State oil company.

It is also relevant to note that Mexico is the only country in the region in which the State oil company, Pemex, possesses a monopoly in the critical upstream sector, derived from the country's constitution. This has major implications for Mexico's ability to replenish its oil and gas reserves; sustain its exports of oil; and satisfy the steady growth in the national

Table 1.16: Structure of LCR Oil Sector

Countries	*SOE*	*Independent Institution Contracting Upstream*	*Upstream Monopoly*	*Comments*	*Midstream Monopoly*	*Importation Monopoly*	*Downstream Monopoly*
Argentina	ENARSA	Central/ Provincial Governments	No	Recently Created	No	No	No
Bolivia	YPFB	No	No		51% Share in Refining	Yes	No
Brazil	Petrobras	Yes	No	2/3 Upstream with Private Sector	No	No	No
Chile	ENAP	No	No		Yes	Yes	No
Colombia	Ecopetrol	Yes	No	Will Initiate Partial Privatization	Yes	Yes	No
Ecuador	PetroEcuador	No	No		Yes	Yes	No
Mexico	Pemex	No	Yes		Yes	Yes	Yes
Paraguay	Petropar	Yes	No		No	100% of Diesel w/Subsidies	No
Peru	PetroPeru	Yes	No	Returning to the Upstream	No	No	No
Trinidad and Tobago	Petrotrin	Yes	No	Private Sector and SOE in Upstream Production	Yes	Yes	No
Uruguay	ANCAP	No	No	Monopoly Confirmed by Referendum	Yes	Yes	No
Venezuela, R.B. de	PDVSA	No	No	Private Sector and SOE in Upstream Production	Yes	Yes	

Sources: Private Communication – Eleodoro Mayorga Alba (The World Bank).

demand for oil and gas. This is important given that Mexico currently imports about 17 percent of the gas it consumes, and this level of imports is expected to increase in the next decade unless there is a major increase in resources deployed in E&P. Since 2001, Pemex has tried to use Multiple Service Contracts (MSCs) to have private companies produce natural gas in nonassociated fields. However, this strategy does not appear to have increased gas production to date. Among the major companies, only Petrobras and Repsol have signed up for these contracts, and a few minor companies have also participated. These contracts pay for services, but all the resources remain in Pemex's ownership since there is no risk- or profit-sharing. The issue of Mexico's oil and gas E&P prospects is discussed further below.

While Pemex maintains a monopoly over "upstream" E&P of oil and gas, as well as in the "midstream" and "downsteam" oil sector, in the case of natural gas transport, Pemex has lost control over the main gas transmission pipelines, which are now regulated by an Energy Regulatory Commission (Comisión Reguladora de Energía – CRE). Additionally, private companies are allowed to build pipelines, store and distribute natural gas for domestic consumption. However, without additional natural gas suppliers, Pemex retains its monopoly over the gas sector. This situation may change with completion of Liquefied Natural Gas (LNG) import terminals which are being built by private consortia involving Chevron, Repsol and others, resulting in a significant increase in LNG imports that are envisaged over the next decade. Hence, in the natural gas sector, there is a potential structure to foster competition but, so far, Pemex has maintained a dominant market position. Finally, it is worth noting in Table 1.16, that it is only in Venezuela and Mexico that the State-owned companies have monopolies in both the “midstream” and “downstream” petroleum product sector. The situation regarding the “midstream” refinery sector is discussed below.

Today’s oil and gas realities are very different to those of the 90s, which implies that new strategies are called for. Less than 15 percent of the world’s oil and gas resources belong to the IOCs and, in most regions of the world with significant petroleum resources and a strong sense of national interests, it has become increasingly politically difficult for the State to surrender further ownership over these resources to the IOCs, since currently these are viewed as strategic resources from both national and global perspectives. As such, since the National Oil Companies (NOCs) can be expected to continue to play a role, the issue for the World Bank Group becomes which countries wish to modernize, commercialize and corporatize their NOCs and are ready to engage with the World Bank Group to effect this strategy, which requires a separation of the institutional, contractual and regulatory roles of the State from the investment, production and commercial responsibilities of the NOC.

Given the above context, the countries in the Region that possess large hydrocarbon resources, Venezuela, Bolivia, Ecuador and Mexico, have opted to keep close State control and intervention over the sector. The adjustment of retail product prices reflecting a closer relationship with international prices in these countries has also not materialized. In Venezuela, high international oil prices have resulted in higher subsidies at the national level, and a larger dependence on the oil sector as the engine of economic growth, resulting in a limited diversification of the economy. However, pragmatism does exist, since, in Venezuela, the gas sector is open to private operators. In this context, regulatory frameworks are being adapted and State participation is viewed as important to provide the long-term stability required for gas infrastructure investments. Additionally, Petróleos de Venezuela S.A. (PDVSA) has suffered hemorrhage of many of its highly skilled staff and has been absorbed in contract renegotiations and social programs. In Ecuador, a crisis in public finances is imminent as a result, in large part, of subsidies equivalent to about 25 percent of the national budget. Furthermore, doubts exist as to the technical capacity of PetroEcuador to recover production from the larger fields in the country.

Colombia offers a good example of policies that could be adopted to attract private investment into the development of local gas markets. Based on modest but sufficient reserves of associated and nonassociated gas, Colombia, over the last decade, has been able to develop an integrated gas transport and distribution network which operates under healthy economic conditions. Additionally, Peru was also able, in 2001, to start the exploitation of the Camisea gas condensate fields. Plans in this country include LNG exports and pipelines to extend the use of gas in interior provinces.

In contrast to the open approach to reform and liberalization in Brazil, Colombia and Peru noted above, public opposition to privatization has been manifested explicitly through referenda and the electoral process in countries such as Uruguay and Argentina. The recent nationalization policy in Bolivia has resulted in a legal hiatus, which has dampened the interest of potential gas importers in major gas export projects. Monetization of the country's large gas reserves are now focused on the renegotiation of export contracts with Brazil and Argentina. Finally, in Bolivia, large Liquefied Petroleum Gas (LPG) subsidies severely limit the extension of a natural gas domestic market.

In this context, despite the very tough new conditions being imposed on the foreign oil companies in Venezuela, Ecuador and Bolivia, some of the players have chosen to remain. This highlights the complexity of the process given the scale of oil and gas, as well as heavy oil resources at stake. Indeed, it is likely that once the negotiation wave is completed, the commitments for exploration could start to increase among those players that have remained.

RETAIL DIESEL OIL AND GASOLINE PRICES OF NET OIL EXPORTERS

Retail price levels of diesel oil and gasoline are invariably matters of political sensitivity in all societies. Concurrently, the challenge faced by the fiscal authorities is to ensure that all acquisition costs in delivering these products to consumers are fully covered, and that appropriate fiscal taxes are levied, among others, to cover the costs at least of road maintenance and encourage efficient use of fuels. Table 1.17 shows these prices as of November 2006 for the Net Oil Exporters (NOEs) in LCR – Argentina, Bolivia, Colombia, Ecuador, Mexico, Trinidad and Tobago, and Venezuela.

The notional yardstick used to assess relevant levels of these prices was taken as the USA average retail prices of these products, which were US¢69 and 63/l for diesel oil and gasoline, respectively**.** These two prices include industry margins, VAT and US¢10/l for road funds. As such, these yardsticks provide estimates of the levels of retail prices for a nonsubsidized road transport policy**.**

Table 1.17: Retail – Diesel Oil and Gasoline Prices in November 2006 US¢/(liter)

Net Oil Exporters	*Diesel Oil*	*Gasoline*
Argentina	48	62
Bolivia	47	54
Colombia	57	98
Ecuador	39	47
Mexico	52	74
Trinidad and Tobago	24	43
Venezuela, R.B. de	2	3

Source: www.gtz.de/de/dockumente/en-international-fuel-prices-final.pdf.

It is evident from Table 1.17 that, in all seven countries, diesel oil is highly subsidized, while both products are virtually free in Venezuela, with Trinidad and Tobago having the next lowest prices, implying subsidies of about two-third and one-third for diesel oil and gasoline, respectively. In the case of gasoline, Colombia and Mexico stand apart with prices well above the notional yardstick – gasoline represents about 47 percent and 37 percent, respectively, of the petroleum product market in these two countries. In these two markets, diesel oil enjoyed subsidies of between 18-25 percent, respectively, while accounting for 39 percent of the product market in Colombia, and just 19 percent in the Mexican market. In Mexico, the practice has been to set retail prices to meet inflation targets, by holding domestic refined product prices constant in real terms. In periods of volatile international oil prices, when the country is importing petroleum products to meet demand, the domestic price becomes quickly subsidized.

In Argentina, diesel oil, which was subsidized to a level of about 30 percent, represents some 62 percent of the petroleum product market compared with gasoline's share of just 15 percent. Since the reforms of the 90s, the oil sector has been almost entirely in private sector ownership, and the government had no formal price-setting role. However, during the last three years, through the use of export tariffs, political negotiation and pressure**,** the government has controlled retail prices. This practice began when rising international oil prices, in early 2004, began to put pressure on Argentina's inflation rate. The export tax regime reduced export of crude oil and products. However, what this policy has done is to force private sector companies to transfer part of their crude oil rent to consumers of products at subsidized prices. The long-term implications of current pricing policies are serious. The country's crude oil production fell 5 percent in 2005, continuing the downward trend in output and reserve since 1998. Major investment in exploration and development is called for to arrest the decline, however, whether the investments will materialize in the current policy environment remains to be seen.

Subsidized petroleum product prices, particularly of the transport fuels in the NOEs, is a perennial policy issue in both higher income economies and in poorer countries such as Bolivia and Ecuador, where such policies severely aggravate their governments' fiscal deficits.

RETAIL DIESEL OIL AND GASOLINE PRICES OF NET OIL IMPORTERS

Table 1.18 shows the retail diesel oil and gasoline prices as of November 2006 for most of the Net Oil Importer (NOI) countries in LCR.

In contrast with the situation of the NOEs**,** gasoline is not subsidized in any of the NOIs, and the level of subsidy in the four Central American countries for diesel oil is between 3-15 percent of the notional yardstick price. This reflects sound pricing policy by the NOI governments, though, in a few countries, additional fiscal resources could be mobilized through higher prices on diesel oil, especially when it is recognized that this is a product used primarily by heavy vehicles which do greatest damage to road infrastructure.

Table 1.18: Retail Diesel Oil and Gasoline Prices November 2006 US¢/(liter)

Net Oil Importers	*Diesel Oil*	*Gasoline*
Barbados	79	111
Brazil	84	126
Chile	86	109
Costa Rica	67	98
Dominican Republic	75	103
El Salvador	80	82
Guatemala	64	78
Honduras	73	89
Jamaica	75	82
Nicaragua	58	67
Panama	60	70
Paraguay	77	97
Peru	86	122
Suriname	94	94
United States of America	69	63

Source: www.gtz.de / de / dockumente / en-international-fuel-prices-final.pdf.

CRUDE OIL PRODUCTION AND PRODUCT CONSUMPTION OF NET OIL EXPORTERS

LCR oil production over the period 1998-2004 has been disappointing, given that global demand for petroleum was robust, and the region possess some of the largest oil and gas resources globally after those of the Middle East and the Russian Federation. Table 1.19 shows the crude oil production and petroleum product consumption in 1998 and 2004 in the NOE countries.

Of particular significance is the decline in oil production in this period of some 850,000 bbls / day in Venezuela, Argentina and Colombia (the second, third and fourth largest of the NOE producers in LCR). In both Argentina and Venezuela, the economic and political changes that unfolded post-2000 have had, and continue to have, major impacts on the petroleum industry, as discussed earlier. These declines are in contrast to the significant production increase (40 percent) on a large production base in Ecuador, accompanied by important increases in Trinidad and Tobago (27 percent) and Bolivia (33 percent), though on smaller production bases, and a modest additional production rise (10 percent) in Mexico on a large production base. Petroleum consumption rose by small amounts in most NOEs over the six-year period save in Trinidad and Tobago and Venezuela, where annual consumption increased by about 10 percent and 4.2 percent, respectively, undoubtedly driven by the very low retail prices of petroleum products and rapid economic expansion in the case of Trinidad and Tobago. In the case of Argentina, the decline in oil consumption during the period was driven by the combined effects of the economic crisis post-2000, and further penetration of natural gas into the energy supply mix rising to over 50 percent by 2004.

Table 1.19: Oil Production and Petroleum Product Consumption of NOEs 1998 and 2004 (000s barrels/day)

Net Oil Exporters	*Crude* 1998*	*Production 2004*	*% Growth*	*Product 1998*	*Consumption 2004*	*% Growth*
Argentina	920	825	(10)	490	470	(4)
Bolivia	45	60	33	40	45	13
Colombia	745	545	(27)	290	270	(7)
Ecuador	380	530	40	135	150	11
Mexico	3,500	3,850	10	1,950	1,970	1
Trinidad and Tobago	130	165	27	22	35	59
Venezuela, R.B. de	3,410	2,855	(16)	455	560	23
Subtotal	**9,130**	**8,830**	**(3)**	**3,382**	**3,500**	**4**

Sources: EIA, DOE Oil Production and Product Consumption Data from Web pages for 1998 and 2004.
* Includes natural gas plant liquids, other liquids and refinery processing gains.

OIL PRODUCTION AND PETROLEUM PRODUCT CONSUMPTION OF NOIs 1998 AND 2004

Table 1.20 summarizes the oil production and product consumption in 16 of the NOIs in LCR.

There are two salient points to note. First, there are seven NOI countries (Barbados, Brazil, Chile, Cuba, Guatemala, Peru and Suriname) in LCR which are oil producers and their aggregate crude oil production increased from 17 to 23 percent of the total LCR crude production between 1998 and 2004. This arose primarily because of the 46 percent increase (575,000 bbls / day) in Brazilian production. This was in stark contrast with the 3 percent production decline in the NOEs over the years noted here. Second, the only other NOI production increases, though on small bases, were in Cuba and Suriname. Chile, Guatemala and Barbados all experienced production declines on small bases while Peru had a 17 percent production drop on its larger base of 115,000 bbls / day in 1998.

As far as the evolution of the NOIs' demand for petroleum products is concerned between 1998-2004, two factors emerge from Table 1.20. First, the growth of demand in the seven NOI producers was very modest in the larger markets with total increases over the period ranging from -2 percent in Peru to 5 percent in Cuba, with Brazil and Chile registering rises of 2 percent and 0 percent, respectively. The exception was that of Guatemala at some 16 percent. It is relevant to recall that Table 1.20 shows that the four larger NOI markets (Brazil, Chile, Cuba and Peru) have maintained rather robust retail pricing policies for diesel oil and gasoline. Second, in contrast, the demand in the three Central American countries, Honduras, Costa Rica and Nicaragua, averaged annually between a 4-5 percent increase, while the Dominican Republic experienced explosive growth of some 8 percent annually. As shown in Table 1.18, in both Costa Rica and Nicaragua, diesel oil which accounted for between 35-40 percent of the petroleum market was priced below the notional yardstick.

Table 1.20: Oil Production and Petroleum Product Consumption of NOIs 1998 and 2004 (000s barrels/day)

Net Oil Importers	*Crude** 1998*	*Production 2004*	*Growth %*	*Petroleum 1998*	*Consumption 2004*	*Growth %*
Barbados	1.5	1	(33)	10	11	10
Brazil	1,265	1,840	46	2,095	214	2
Chile	20	15	(25)	240	240	–
Costa Rica	–	–	–	35	44	26
Cuba	35	65	86	194	204	5
Dominican Republic	–	–	–	86	127	48
El Salvador	–	–	–	38	43	13
Guatemala	25	20	(20)	58	67	16
Honduras	–	–	–	29	37	28
Jamaica	–	–	–	68	71	4
Nicaragua	–	–	–	22	27	17
Panama	–	–	–	85	79	(7)
Paraguay	–	–	–	24	27	13
Peru	115	95	(17)	159	156	(2)
Suriname	7	10	43	10	11	10
Uruguay	–	–	–	44	38	(13)
Subtotal	**1,468**	**2,036**	**39**	**3,197**	**3,322**	**4**
LCR Total	**10,598**	**10,866**	**3**	**6,579**	**6,822**	**4**

Sources: EIA, DOE Oil Production and Product Consumption Data from Web pages for 1998 and 2004.
* Includes natural gas plant liquids, other liquids and refinery processing gain.

DRY NATURAL GAS PRODUCTION AND CONSUMPTION IN 1998 AND 2004

Table 1.21 highlights the production and consumption of dry natural gas in 1998 and 2004 in the three Net Gas Exporters (NGEs) – Argentina, Bolivia, and Trinidad and Tobago – and the remaining 11 gas consuming countries of which nine are gas producers with three being also net importers (Brazil, Chile and Mexico) and two are nonproducing net importers (the Dominican Republica via LNG and Uruguay via pipeline gas). Indeed, in contrast with the very modest 3 percent increase over the period in LCR crude oil production, in the case of dry natural gas, LCR production rose by 37 percent.

Dry natural gas production experienced explosive growth in the NGEs between 1998 and 2004 with increases ranging from 50 percent in Argentina to over 200 percent in Bolivia and Trinidad and Tobago, though on smaller bases. Indeed, in all NGEs, gas exports increased dramatically within the six-year period – virtually trebling in Bolivia to 760 million cubic feet per day (mmcfd), and in Trinidad and Tobago rising to 1,350 mmcfd in 2004 from zero in 1998 via the LNG route. This dramatic growth in production also witnessed significant growth in national consumption of gas ranging from 24 percent in Argentina, 147 percent in Bolivia and 52 percent in Trinidad and Tobago.

Table 1.21: Dry Natural Gas Production and Consumption 1998 and 2004 (million cubic feet/day)

	Dry Gas Production		*Growth*	*Dry Gas Consumption*		*Growth*
	1998	*2004*	*%*	*1998*	*2004*	*%*
Net Exporters						
Argentina	2,860	4,340	52	2,950	3,665	24
Bolivia	295	970	229	85	210	147
Trinidad and Tobago	890	2,720	206	900	1,370	52
Subtotal	**4,045**	**8,030**	**99**	**3,935**	**5,245**	**33**
Producers/Net Importers						
Barbados	3	3	–	3	3	–
Brazil	560	935	67	560	1,670	199
Chile	190	105	(45)	310	805	160
Colombia	605	595	(2)	605	600	(1)
Cuba	40	35	(12)	40	35	(12)
Dominican Republic	–	–	–	–	20	
Ecuador	10	15	50	10	15	50
Mexico	3,470	4	16	3,520	4,880	39
Peru	40	80	100	40	80	100
Uruguay	–	–	–	–	10	
Venezuela, R.B. de	3,040	2,630	(13)	3,040	2,630	(13)
Subtotal	**7,968**	**8,408**	**5**	**8,128**	**10,728**	**32**
LCR Total	**12,003**	**16,438**	**37**	**12,063**	**15,973**	**32**

Sources: EIA, DOE Oil Production and Product Consumption Data from Web pages for 1998 and 2004.

Indeed, the most dramatic increase in gas production from 700 mmcfd to 3,800 mmcfd in the short period between 1997-2006 occurred in Trinidad and Tobago, of which about 2,200 mmcfd in 2006 was exported as LNG, with only about 5 percent of this destined to the Dominican Republic and Puerto Rico within LCR. The implementation of major new gas export projects, such as further LNG trains, from Trinidad and Tobago, hinges on proving up additional reserves, either from new prospective areas or from a unitization agreement with Venezuela for the Platforma Deltana field which straddles the maritime boundaries of Venezuela and Trinidad and Tobago.

Among the three gas-producing net importers, Brazil once more witnessed a large increase (67 percent) in production over the period with consumption rising by about 200 percent with this being satisfied by increased imports from Bolivia. Mexico recorded about 16 percent growth on its large production base, which, though important, fell far short of stemming its dramatic rise in gas imports amounting to some 18 percent of demand by 2004 which had increased by 39 percent over the six-year period from 1998. Chile experienced a significant

45 percent decline in production on a 1998 base of 190 mmcfd, with a concomitant large rise in gas consumption of some 160 percent to about 805 mmcfd in 2004, driven by pipeline imports from Argentina.

In the case of the six gas-producing nonimporters – Barbados, Colombia, Cuba, Ecuador, Peru and Venezuela – Ecuador and Peru witnessed significant increases on small production bases, while Colombia experienced a modest decline of -2 percent, and Venezuela and Cuba showed more significant drops in production of about -13 percent accompanied by equivalent decreases in consumption.

To illustrate more dramatically the data in Table 1.21, Figure 1.21 highlights natural gas production in 1998 and 2004 in 10 of the gas-producing countries: Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Mexico, Peru, Trindad and Tobago, and Venezuela.

However, despite the significant increases in gas production over the period, gas imports have had to rise dramatically, from very low bases, to meet demand in Mexico, Brazil and Chile between 1998 and 2004. This is well illustrated in Figure 1.22.

RELATIVE SHARES OF NATURAL GAS AND OIL IN THE ENERGY MIX BETWEEN 1998 AND 2004 IN SELECTED COUNTRIES

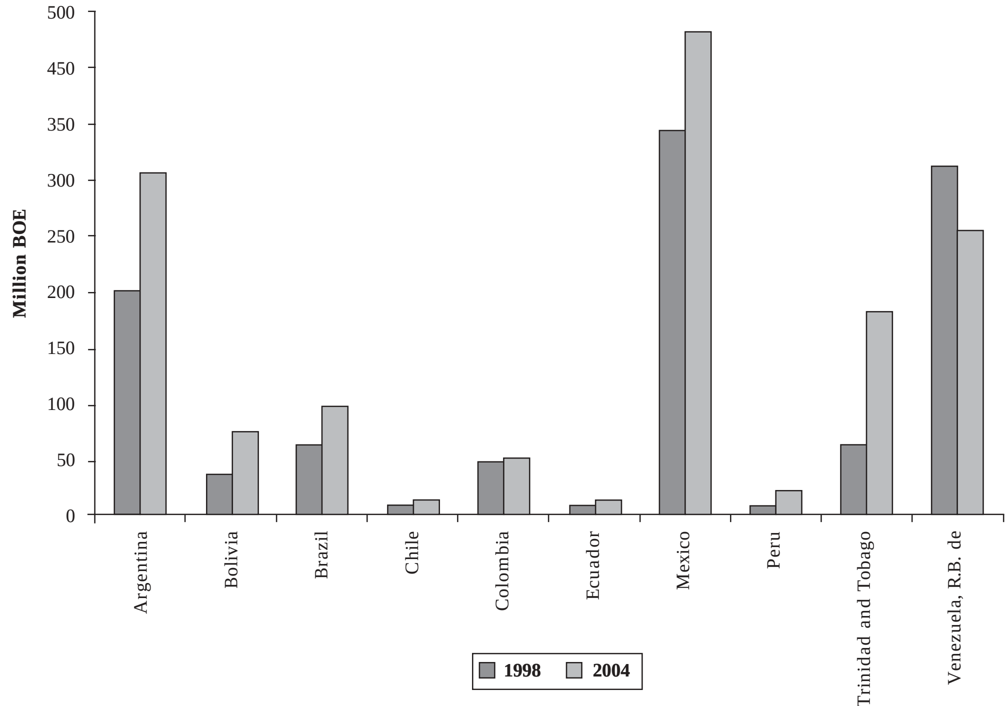
Figures 1.23 and 1.24 graphically illustrate the extent to which gas has penetrated at the expense of oil in the energy supply mix between 1998 and 2004 in Argentina, Brazil, Chile and Mexico. In the cases of Argentina and Mexico, despite the already significant role of gas in the energy supply mix in 1998 (about 43 and 31 percent, respectively), by 2004 its share had risen to above 50 percent in Argentina, and about 38 percent in Mexico. Additionally, in Brazil and Chile, the share of gas relative to 1998 doubled by 2004 to 9 and 25 percent, respectively.

The corresponding decline in the share of oil in the energy supply balance in these four countries is shown in Figure 1.24.

Figure 1.24 illustrates that oil's share has declined from about 43 to 33 percent in Argentina over the period; from about 45 to 40 percent in Brazil and Chile; and, from 51 to 47 percent in Mexico.

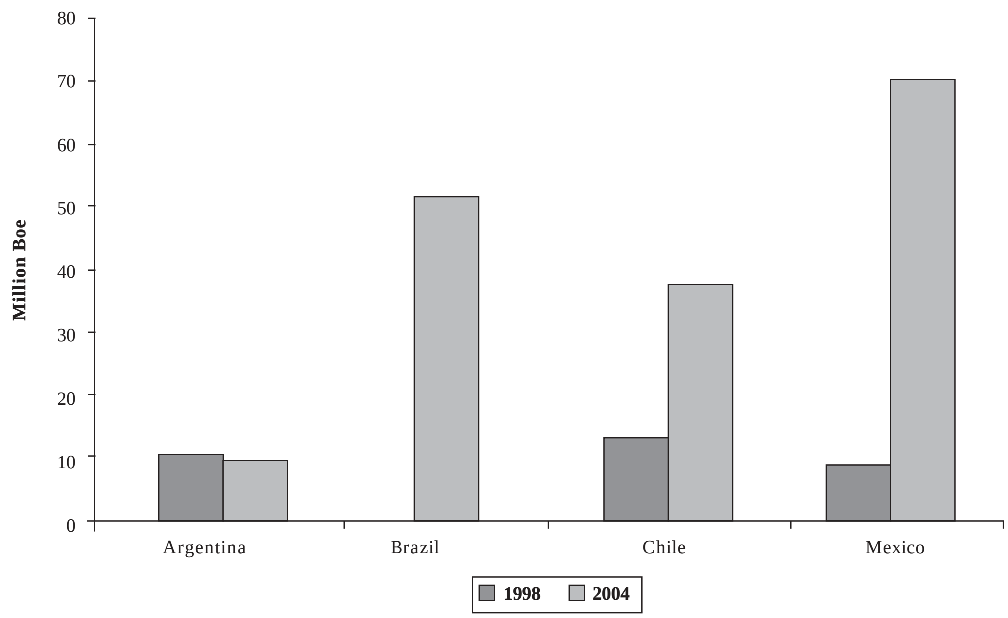
Beyond the electric power and industrial markets, natural gas has proven itself as an important fuel, in the form of Compressed Natural Gas (CNG), in addressing public transportation needs in urban settings. Ever-expanding cities are demanding cleaner fuels, especially in those at high altitudes. In this context, the experiences of Colombia and Argentina in the use of CNG in public urban transportation need to be assessed with a view to assisting other countries in the region implement similar programs. The launching of such programs may require, initially, incentives in certain urban environments.

Figure 1.21: Gas Production 1998 and 2004



Sources: EIA, DOE Natural Gas Production and Imports from Web pages for 1998 and 2004.

Figure 1.22: Gas Imports 1998, 2004

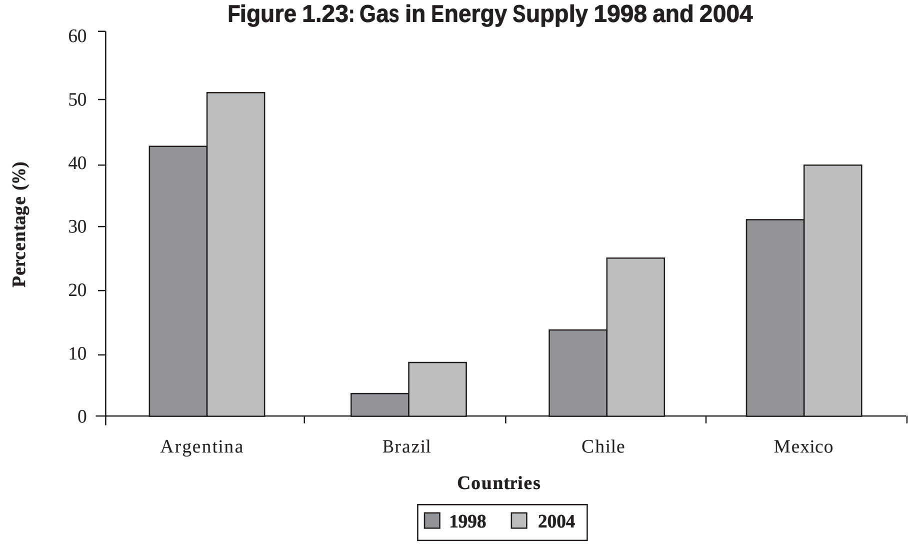


Sources: EIA, DOE Natural Gas Production and Imports from Web pages for 1998 and 2004.

SHARES OF FUELS IN 2004 IN THE ENERGY SUPPLY MIX OF NOEs

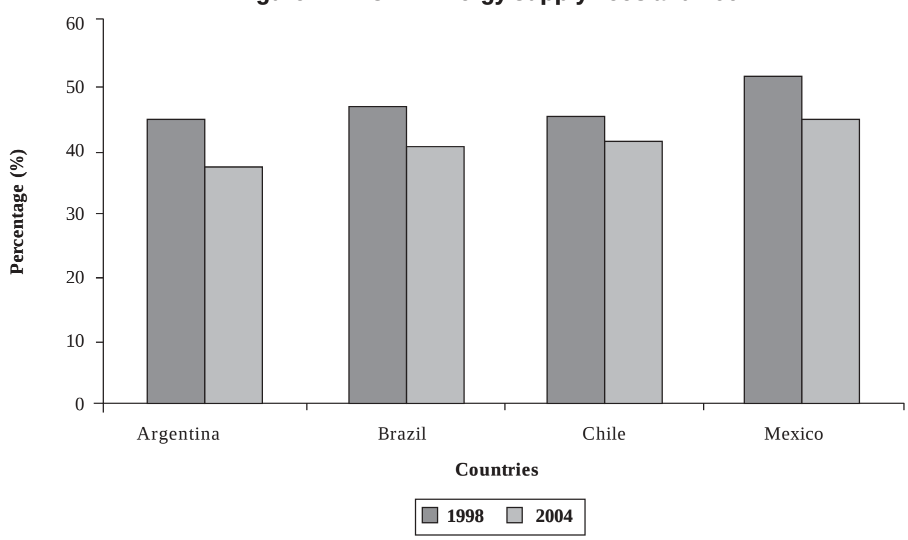
Table 1.22 shows the breakdown in the shares of different fuels in the energy supply mix for the seven NOE countries.

Figure 1.23: Gas in Energy Supply 1998 and 2004



Sources: EIA, DOE Energy Supply Data from Web pages for 1998 and 2004.

Figure 1.24: Oil in Energy Supply 1998 and 2004



Sources: EIA, DOE Energy Supply Data from Web pages for 1998 and 2004.

There are four key issues highlighted in Table 1.22**.** First, Trinidad and Tobago is almost a completely gas-driven economy with 94 percent of energy supply derived from this source. Second, in both Argentina and Bolivia, gas contributes more than 50 percent of the energy supply with hydro being the third most significant energy source after oil. Third, in Venezuela and Mexico, though large oil exporters, natural gas supplies about two-fifth of their energy supply, and, in Colombia, about one-quarter. Indeed, Colombia possesses one of the most diversified energy supply mixes in LCR among modern energy sources, with coal and hydro together accounting for about 60 percent of the oil's share in the supply mix. Additionally, in Venezuela, hydro has an equal share in the supply mix to oil (30 percent), with gas and hydro together contributing more than double that of oil. Fourth, Ecuador is the only NOE in which gas plays a relatively small role in the

Table 1.22: Share of Fuels in the Energy Balance 2004 (percentage %)

	Oil	*Gas*	*Coal*	*Hydro*	*Cane*	*Wood*	*Nuclear*	*Geo-thermal*
Net Oil Exporters								
Argentina	32	56	1	5	1	1	3	0
Bolivia	27	51	0	10	4	5	0	0
Colombia	39	25	8	15	3	8	0	0
Ecuador*	68	5	0	7	3	3	0	0
Mexico	47	38	5	3	1	3	1	1
Trinidad and Tobago	4	94	0	0	0	0	0	0
Venezuela, R.B. de	30	40	0	30	0	0	0	0

Source: Organización Latinoamericana de Energía (OLADE) energy balances (2004).
* Reinjected gas accounts for about 70 percent of gas produced or 12 percent of the energy supply.

overall energy supply compared to the other NOEs, and in which the dependence on oil is greater than 50 percent. Indeed, it is evident that in the NOEs (other than Ecuador), the transition away from high dependence on oil in supplying energy for their national economies is already well under way, with gas and hydro leading the thrust, and coal playing a smnaller but relevant role in Colombia and Mexico. This is important for future policy since it implies that priority be given to deepening the penetration of natural gas in these markets, and intensifying the development of large hydro projects as key components to enhance energy security while concurrently addressing the “clean or cleaner energy” agenda.

SHARES OF FUELS IN 2004 IN THE ENERGY SUPPLY MIX OF NOIs

Table 1.23 shows the fuel shares in the energy supply mix in 2004 for 16 NOIs in LCR.

There are five salient points to note in Table 1.23**.** First, the very high dependence on imported oil in the energy supply mix in Barbados (86 percent), the Dominican Republic (78 percent), Jamaica (86 percent) and Panama (72 percent), as well as in the smaller Caribbean islands (not shown in Table 1.23) where the ratio is in excess of 85 percent, in most cases. Though the share of oil in Haitian energy supply is the lowest at 26 percent among the NOIs, this reflects the low level of economic development as indicated by its very high dependence on woodfuels (69 percent). Second, in both Brazil and Chile, oil only contributes 40 percent to the energy supply with the diversification away from oil being extensive across other energy sources. This is impressive, particularly in Chile (a country not endowed with abundant nonhydro energy resources), in which natural gas, coal and hydro together contribute about 13 percent more to supply than oil. Third, in the Central American countries of Guatemala, Honduras and Nicaragua, the dependence on woodfuel remains high, ranging from about 32-47 percent, which accounts for the somewhat

Table 1.23: Shares of Fuels in the Energy Balance 2004 (percentage %)

	Oil	*Gas*	*Coal*	*Hydro*	*Cane*	*Wood*	*Nuclear*	*Geo-thermal*
Net Oil Importers								
Barbados	86	6	0	0	7	0	0	0
Brazil	40	9	6	13	14	13	3	0
Chile	40	25	12	8	0	15	0	0
Costa Rica	50	0	1	24	3	9	0	13
Dominican Republic	78	3	4	2	4	5	0	0
El Salvador	46	0	0	3	6	28	0	17
Guatemala	40	0	4	3	11	41	0	0
Guyana	53	0	0	0	21	26	0	0
Haiti	26	0	0	2	3	69	0	0
Honduras	52	0	3	5	6	32	0	0
Jamaica	86	0	2	1	4	5	0	0
Nicaragua	40	0	0	1	7	47	0	1
Panama	72	0	0	10	3	16	0	0
Peru	50	10	5	15	3	13	0	0
Suriname*	60	0	0	14	0	5	0	0
Uruguay*	51	3	0	18	0	13	0	0

Source: OLADE energy balances (2004).
* balance incomplete.

lower contribution of oil to the supply mix (40-52 percent), and also illuminates the challenges in formulating energy and development policy. Fourth, as the geothermal energy leaders in LCR, Costa Rica and El Salvador obtain 13 percent and 17 percent, respectively, from this source in the energy supply mix and, in the case of Costa Rica, the additional large role of hydro (24 percent) in supply contributes to reducing the oil share to 50 percent. Finally, though Peru produces about 60 percent of its oil requirements, its supply mix is well diversified with hydro, gas and coal contributing about 60 percent of oil's share to the energy supply.

MEXICAN OIL AND GAS E&P AND RESERVE POSITION

As shown in Table 1.16, Mexico is the only LCR country in which the NOC, Pemex, has a monopoly in upstream oil and gas E&P. This raises the issue of the adequacy and effectiveness of Pemex's exploration investments to boost the country's oil and gas resource base to ensure that production can continue to be expanded over the long term. A recent analysis of Pemex's 2006 Annual Report, which gave details of the Proven, Probable and Possible (3P) reserves by Wood Mackensie,[9] compared this data with earlier years to review the trends and arrive at its own assessment of the situation.

In early 2006, Pemex announced a new oil discovery made with the Noxal-1 well in the deep offshore western Coatzacoalcos province which is considered to be Mexico's last great exploration zone. The water depth of this well was 935 meters (m). The scale of the discovery in the Noxal structure is unclear but could be in the region of a few hundred mn bbl, though the entire deep offshore province could have a potential of up to 10 billion (bn) bbl. This could be a significant "just-in-time" find, since though Pemex has been able to increase oil and gas production over the past several years, it has been unable to offset the steady decline both in its Proven Oil and Gas (1P) reserves, and its Proven and Probable (2P) reserves despite a significant increase in E&P investment since 1999.

Table 1.24 shows Pemex's Reserve to Production Ratios (R:P) based on the 2005 estimates based on 1P; 2P; and Proven, Probable and Possible (3P) reserves. Oil and gas production levels in 2005 were 1.2 bn bbl and 1.8 tera cubic feet (Tcf), respectively.

What Table 1.24 illustrates is that R:P based on 1P for both oil and gas of 9.5 and 10.3 years, respectively, are low. These improve to 18.9 and 20.7 years, respectively, based on 2P reserves, and to 26.7 and 32.2 years, respectively, based on 3P reserves. However, most of Pemex's oil and gas possible reserves are "locked up in the problematic Chicontepec field" which present a major challenge to monetize.

As far as reserve replacement through exploration is concerned, Table 1.25 shows the trend based on the percentage reserve replacement for 2P and 3P reserve discoveries.

In the case of oil, the 2P replacement of 17 percent has not been encouraging even between 2003-05, but the 3P was much improved at 45 percent over the same period. For gas, the success was much more encouraging than for oil with 2P and 3P replacement levels of 56 percent and 98 percent, respectively, for the periods 2003-05.

The last aspect of reserve replacement is based on reserve re-evaluations in existing fields. These re-evaluations exclude the reserves that are used in production in each year. For oil, field re-evaluations witnessed a *downgrade in reserves* over the period 2001-04, which were not offset by exploration successes. In 2005, the integrated reserve replacements (that is, including exploration successes) at the 2P and 3P levels were 14 and 82 percent respectively. In the case of gas, exploration success did not offset field re-evaluations in 1999

Table 1.24: 2005 Reserve/Production Ratios for Proven, Probable and Possible Reserves

R/P Ratio Oil Years			*R/P Ratio Gas Years*		
1P	2P	3P	1P	2P	3P
9.5	18.9	26.7	10.3	20.7	32.2

Source: The Wood Mackenzie "Upstream Insights" (2006).

[9] Upstream Insights, April 2006, "*Mexico: Decline in Oil and Gas Reserves Continues Despite Increased E&P Investment,*" by Wood MacKensie.

Table 1.25: Percentage (%) Reserve Replacement Through Exploration

Commodity	*% 2P Reserve Replacement*	*% 3P Reserve Replacement*
Oil	14% (1999-2005) 17% (2003-05)	27% (1999-2005) 45% (2003-05)
Gas	45% (1999-2005) 56% (2003-05)	60% (1999-2005) 98% (2003-05)

Source: The Wood Mackenzie "Upstream Insights" (2006).

and 2001-03, with only 2004 and 2005 showing integrated reserve replacements between 100-150 percent on a 2P basis.

Pemex's E&P investment increased significantly since 1999. In 1999, exploration investment amounted to US$0.5 bn which rose to US$1.2 bn by 2005. Concurrently, capital and operation investments increased from US$3.8 bn to US$8.4 bn over the same period. While oil and gas production has increased over this period, the data above indicate that the integrated reserve replacement has not been as successful. The challenge before the company is to reverse the reserve decline trend.

Pemex has set two targets regarding reserve replacement. First, to increase reserve replacement through exploration steadily on a 3P basis reaching 76 percent by 2006, and 100 percent by 2010. Second, to achieve 77 percent integrated proven reserves replacement in 2010. In 2005, this rate was 25 percent, and this was the best year since 1999. These are not easy targets to meet, and this raises the policy issue of the timing of Mexico opening its upstream oil and gas sector to participation by foreign companies.

POLICY ISSUES FACING THE MEXICAN OIL AND GAS SECTORS

The assessment of Mexico's oil and gas E&P prospects is compounded by recent warnings[10] that the giant Cantarell oil field, which accounts for nearly 60 percent of Mexico's daily output, has entered into an early and sharp decline. Indeed, Cantarell's production in 2007 and 2008 is estimated to experience an annual reduction of 11 percent and 15 percent, respectively, on the previous year. This would imply its production could reach 1,430 bbl / day in 2008 from 1,905 bbl / day in 2006. Additionally, Pemex faces the prospect of production costs rising from about US$4 / bbl in Cantarell to US$8-10 / bbl in the expensive geological structures of Chicontepec, and about US$12 / bbl for future discoveries in the deepwater Gulf of Mexico. Declining reserves; increasing production costs and increasing national demand for petroleum products and natural gas resulting in rising imports of both of these fuels, allied with the major role that Pemex revenues play in the federal government's budget (discussed further below), raise major issues about the ability of Mexico to allocate the financial and skilled human resources required to meet its oil and gas requirements and, hence, about the sustainability of the present investment model for the oil and gas sectors.

These concerns are compounded by the recent statement by Pemex's CEO that the company would need US$18 bn annually for the next 10 years, relative to US$10 bn annually in recent years, if it is to seek to address the myriad issues facing the sector. Given Mexico's substantial nonassociated gas reserves, this is an area of investment in E&P that requires high priority. First, to try to keep pace with increasing gas demand and, second, reverse the trend of increasing gas imports from the United States, and their high price volatility, which is unlikely to abate significantly with increased LNG imports that are planned to reduce this dependence. As outlined earlier, the policy of MSC initiated in 2001 to attract private capital into the nonassociated gas sector has not been a success, primarily due to lack of proper incentives or risk-sharing by the private participants.

REFINERIES

Refineries in most LCR countries have continued to be State-owned assets. Most of them were constructed by NOCs in the 60s and 70s, and were designed to serve a protected national market, processing domestic crude oil. During the period of low oil prices in the 90s, most LCR refineries suffered from the combined impacts of low margins and weak profitability, which was experienced internationally; low investment; a growing demand for cleaner products; tax distortions in retail fuel prices which encouraged dieselization of car fleets, thereby further aggravating refinery balances; and the penetration of natural gas into the energy market, which would require major investments to reduce the yields of the fuel oil being displaced by natural gas. Indeed, crude oil primary distillation capacity in LCR only increased marginally by 10.7 percent over the 15-year period 1991-2006 from 7.5-8.3 million bbl / day.

Table 1.26 shows the refinery distillation and processing capacities in 2005, for the 73 refineries in LCR, in the 24 countries with refining capacity. It provides a breakdown of the crude oil distillation capacity as well as the catalytic and thermal cracking capacities and that of reforming. As noted here, most refineries are geared to serve the national protected markets, processing domestic crude oil, with the exception of the major export-oriented refineries in the Netherlands Antilles, Aruba, Trinidad and Tobago, US Virgin Islands and Venezuela within the Caribbean Basin, which represent about 25 percent of the crude oil distillation capacity in LCR.

With higher crude oil prices, refinery margins have improved internationally as a result of the widening spread between crude feedstock and refined products prices and, in some countries, improved domestic pricing policies. The refining sector in the region is in transition. What is critical at this juncture is that during this favorable period, the opportunity be seized to develop a competitive refining industry in the region, which could become a pillar in enhancing regional integration. In countries where local prices move in tandem with international prices, and sector laws have been modernized, private investments in a more

[10] *The World Bank-Mexico Policy Notes* – Chapter 9, Oil and Gas Sector (draft), by Enrique Crousillat and Juan Carlos Quiroz, 2006.

Table 1.26: LCR Crude Oil Refining Capacity January 2005 (000s barrels per day)

Countries	*Number of Refineries*	*Crude Oil Distillation*	*Catalytic Cracking*	*Thermal Cracking*	*Reforming*
Argentina	10	625	149	38	60
Aruba	1	230	0	48	0
Bolivia	2	47	0	0	15
Brazil	13	1,920	500	10	24
Chile	3	227	51	14	26
Colombia	5	286	90	52	0
Costa Rica	1	24	0	7	1
Cuba	4	301	15	0	20
Dominican Republic	2	48	0	0	8
Ecuador	3	176	18	32	13
El Salvador	1	22	0	0	3
Jamaica	1	36	0	0	4
Martinique	1	17	0	0	3
Mexico	6	1,684	375	0	284
Netherlands Antilles	1	320	50	80	20
Nicaragua	1	20	0	0	3
Paraguay	1	8	0	0	0
Peru	6	193	32	0	2
Puerto Rico	2	110	12	0	23
Suriname	1	7	0	3	0
Trinidad and Tobago	1	165	28	32	20
Uruguay	1	50	12	7	12
US Virgin Islands	1	495	142	98	109
Venezuela, R.B. de	5	1,282	232	0	50
Total	**73**	**8,288**	**1,706**	**421**	**696**

Source: EIA, DOE Oil Refining Capacity Web pages, January 2005.

open and competitive framework could be an important source of financing for the major investments required.

On the other hand, the rationalization of the refining sector will undermine further the viability of the small refineries. Lacking the economies of scale to justify investments in deep conversion of fuel oil to yield higher value and cleaner products, these refineries may have to be closed or replaced by larger competitive export-oriented refineries serving broader regional markets. In the past eight years, four small refineries have been shut down in Barbados (4,000 bbl / day), Guatemala (16,000 bbl / day), Honduras (14,000 bbl / day), and a medium-sized plant in Panama (60,000 bbl / day), while six small refineries, each of less than 35,000 bbl / day capacity, but with cumulative capacity of 117,000 bbl / day, remain in operation in six countries – Costa Rica, El Salvador, Nicaragua, Jamaica, Suriname and Paraguay. Decisions to close such refineries are never easy, since they are often mechanisms to access special concessional crude oil from exporters, which was particularly relevant during the first and second oil price shocks when soft financing facilities were only available for crude oil and not for petroleum products.

CROSS-BORDER NATURAL GAS INTERCONNECTIONS

Recent cross-border gas issues which have come to the fore in the interconnections between Chile and Argentina, and Brazil and Bolivia highlight different institutional arrangements. Lessons learned from these experiences should help ensure that the momentum is not lost in deepening and expanding the cross-border gas trade in the region.

Over the last 10 years, the largest gas project has been the Bolivia-Brazil pipeline. The project was made possible by the commitment of Petrobras and the contribution of financial institutions, among which the World Bank Group demonstrated strong leadership. Based on an umbrella State-to-State agreement between Brazil and Bolivia, the pipeline was constructed on time, was able to overcome all environmental and social difficulties that were encountered, and has been operating without major difficulties. One relevant issue was the lower volume transported due to the slower than expected growth in Brazil and years in which hydro utilization was at a maximum due to favorable rainfall. Today, this pipeline is operating close to capacity but its expansion depends on a satisfactory resolution to the ongoing gas price and tariff renegotiations taking place between the two governments and their State companies.

Of course, the recent nationalization of Petrobras' oil and gas production and refining assets in Bolivia has cast a somber shadow over the relationship. This highlights how political changes at the supply source trigger economic disputes which, in turn, have reportedly resulted in Petrobras seeking to diversify its future imported gas supply sources to LNG, despite its higher price volatility. This is a classic example of how rent-sharing issues have given rise to the "obsolescing bargain."[11] This describes a situation in which, once the investment has been sunk and operations commenced, relative bargaining power switches from the company to the exporting country government, thus encouraging the government to try to unilaterally secure a greater share of the economic rent.

Whereas governments remain the main actors in the Bolivia-Brazil pipeline, in the case of Argentina and Chile, the private sector has been the major promoter and owner of the seven gas pipelines connecting Argentinean gas fields to the Chilean market. However, due to the economic crisis in Argentina, and the subsequent rationing of gas supplies in Argentina and

Chile, Chile has been forced to reconsider its energy policy, and is examining options to diversify its primary energy supplies to include imported LNG and coal, thereby reducing increased dependence on Argentine gas supplies. Additionally, Chile was reported to be interested in negotiating a State-to-State agreement with the Argentine government as a possible mechanism that may enhance the stability of the existing commercial arrangements.

As the demand for gas increases, so does the need, ideally, to develop an "integrated" market. The Southern Cone is the gas market in which this is most likely to emerge given the size of gas demand, the availability of gas supplies and the existing pipeline T&D networks. However, given the recent developments which have undermined trust and the sanctity of contracts, this is unlikely to evolve in the near future. Futhermore, in none of the LCR countries is there a "gas commodity supply market," that is, a market in which there are many sellers and buyers of gas, a good gas delivery system and extensive gas use. At present, such markets only exist in the United States, Canada, the United Kingdom and Argentina (prior to the economic crisis), in which the gas price is determined by gas-to-gas competition. In contrast, what occurs in LCR countries are "gas project supply markets" in which there are a few buyers and sellers of gas and limited T&D systems. This results in the gas price being negotiated by contract, with escalation clauses, and so on, and so forth. Here, contracts must be flexible enough to deal with changing circumstances over a 15-20 year horizon, but simultaneously be firm enough to be worth signing. Within this context, the possibility of an "integrated" Southern Cone gas market is not likely to emerge in the near future.

The experience in cross-border pipelines highlights the need for an "umbrella" heads-of-State agreement between the governments involved and, above all, large private sector participation in such projects to ensure the commercial character of the trade. Naturally, complete integration of the gas markets of the Southern Cone, involving a common infrastructure and regulatory framework, is very difficult to envisage given the current political dispensations. However, even in politics, nothing lasts forever and bilateral arrangements between gas producers like Bolivia and Peru to expand existing pipelines to consumer markets in Brazil, Argentina and Chile or to build new pipelines may regain momentum in the coming years. Nevertheless, it will take time to rebuild both confidence in the sanctity of contracts, and to create new institutional mechanisms for the resolution of disputes. If gas is to continue to enhance its position in national and regional energy balances, increasing cross-border gas trade would be a key vehicle to reduce prices to consumers; further diversify energy supplies while strengthening energy security; improving urban air quality and reducing carbon impacts; and, above all, provide producers with expanded markets for their gas as well as higher net back prices.

The creation of appropriate institutional mechanisms to resolve disputes is critical to provide momentum to further expand cross-border gas pipeline trade within the Southern

[11] *"Cross-Border Oil and Gas Pipelines: Problems and Prospects,"* ESMAP Technical Report 035/03, June 2003.

Cone. Outstanding issues that would need to be addressed include: (i) the priority assigned to the national market over and above contractual obligations for the export of gas; (ii) a "supranational" authority with powers for the resolution of disputes; and, (iii) the roles of governments, State companies and private sector companies in the new dispensation. However, it should be noted that, recently, it was reported[12] that Bolivia announced its intention to withdraw from the International Centre for the Settlement of Investment Disputes (of the World Bank) (ICSID), the main international forum for dispute settlement on cross-border investments. This is likely to cast further doubt on the general acceptability of the type of "supranational" dispute resolution mechanisms referred to above, in the current political environment. It highlights further the susceptibility of any mechanisms put in place to resolve investment disputes to fundamental changes in the policies of governments.

Environmental issues will play a greater role in investment decisions on cross-border gas pipelines in LCR than they have in the past, as would be the case in other energy sector projects such as hydro, petroleum exploration and development, coal mining and petroleum refineries. It is now impossible to enter and undertake exploration activities in the territories of indigenous people or to cross the land of a rural community without a formal process of consultation, which would conclude with a specific development program to address the concerns of the impacted community. The World Bank has made, during the last decade, a significant effort to review its role in the extractive industries and, as such, is well placed to facilitate solutions and best practices in these industries. The new safeguards and the acceptance by the international banking community of the Equator Principles is a serious attempt by private investors to adopt a series of guidelines required to enter into new and sustainable investment opportunities in LCR. Increasingly, consultations with local communities are required before starting any project. Tripartite dialogues which include industry, governments and local communities, have evolved and are providing, in many countries, an acceptable framework to develop and enforce regulations. Addressing past liabilities while developing and implementing better social and environmental standards is becoming a major concern in most governments.

CONCESSIONAL FINANCING OF OIL IMPORTS – PETROCARIBE AND THE MESOAMERICA ENERGY INTEGRATION PROGRAM

The PetroCaribe Accord's (PCA's) Memorandum of Understanding (MoU) was signed between the Venezuelan President, Hugo Chavez, and 10 Caricom member States, Cuba and the Dominican Republic on June 29, 2005, in Puerto la Cruz, Venezuela. It represents a new initiative by Venezuela to assist Caribbean countries facing high oil import costs. Earlier initiatives by Venezuela, Mexico, and Trinidad and Tobago in the 70s and the 80s had sought to extend assistance to regional oil importers through various financingmechanisms. The San Jose Accord of Venezuela and Mexico focused on crude oil supplies, while the Trinidad

[12] *"Bolivia and Brazil Resolve Oil Dispute,"* Financial Times, May 11, 2007.

and Tobago facility focused on product supplies. However, a critical difference between these earlier oil facilities and the PCA, is that the PCA seeks, explicitly, to have a "direct trade relationship (with the importing countries' State agencies) without intermediaries in the supply process."

Under the PCA, when the value of petroleum products or crude oil imported under the facility exceeds US$50/bbl, 40 percent of the import cost is eligible for credit financing. The terms of this financing are:

- Duration: one year and renewable;
- Tenor: 25 years loan repayment period;
- Interest rate: 1 percent per annum; and
- Moratorium: two years on principal payments.

The cost of petroleum imports more than doubled between 2000-05 for most Caribbean islands, of which most are nonpetroleum producers. With the resulting increased balance of payments and fiscal pressures, the PCA was welcomed by most Caribbean governments. Barbados, and Trinidad and Tobago are the only two countries that have not participated. Under the financing terms, if a Sinking Fund is established with about 75-80 percent of the credit being assigned to the Fund, the income generated by the Fund through investment in secure bonds would repaythe outstanding debt over the 25-year period, while the remaining 20-25 percent of the credit would be available to the government for use in projects that meet with the approval of the Venezuelan government.

While the mechanism does provide relief, some important concerns of importance for the macroeconomy, include:

- The rapid increase in external indebtedness in countries already burdened by high external debts;
- The use to which governments would put the 20-25 percent of the total credit available to them. A worrisome case scenarios would be its use to reduce the retail price of products while global oil prices remain high; and
- The potential for a deterioration in supply security given that supplies would now be procured only from one source and transported by one supplier, whereas prior to the PCA there were two to three suppliers (IOCs) which procured products from more than one source – mainly, Trinidad and St. Croix, and Virgin Islands.

Subsequent to the launching of the PCA, Mexico announced the Mesoamerican Energy Integration Program (MEIP) initiative which includes Colombia, the Dominican Republic and the countries of Central America. As noted earlier, this program calls for the establishment of a major refinery in Central America, while Mexico has agreed to supply products to the MEIP countries on terms similar to the PCA. However, the Mexican initiative does not have the statist trade objectives of the PCA of “cutting out the middlemen.” Other initiatives within the MEIP include a natural gas pipeline; power transmission lines; power plants; and cooperation on biofuels.

2. Assessment of Future Needs and Challenges

Electricity Expansion Plans

The assessment of future investment needs of the power sector in the region was based on a consolidation of electricity expansion plans for the main countries in the region, prepared by the institutions responsible for energy planning, which were available from public sources. Only recent expansion plans were used (prepared in or after 2005), and when they were not available, the study relied on the estimates of a recent Organización Latinoamericana de Energía (OLADE) study of energy prospects in the region (Table 2.1). In the countries that have established competitive wholesale markets, the expansion plans are only a reference for making informed investment decisions by private investors and other providers. In the case of countries which kept vertically integrated monopolies (Mexico, Costa Rica, Honduras and Venezuela), they are a reference for implementing the investment program of SOEs and contracting energy supply with IPPs under competitive bidding procedures.

Table 2.1: LCR Electricity Expansion Plans, Sources of Information

Argentina	Plan Energético Nacional 2004-08 and Prospectiva Energética LCR, OLADE (2006)
Bolivia	Prospectiva Energética LCR, OLADE (2006)
Brazil	Plano Decenal de Expancao de Energia Eletrica 2006-15, EPE, 2006
Chile	Fijación de Precios de Nudo SIC y SING (octubre de 2006)
Colombia	Plan de Expansión de Referencia Generación-transmisión 2006-20, UPME, junio 2006
Costa Rica	Plan de Expansión de Generación 2006-25, (2006)
Ecuador	Plan de Electrificación 2006-15, (2006)
Guatemala	Prospectiva Energética LCR, OLADE (2006)
Honduras	Plan de Expansión de Generación 2006-20 (2006)
Mexico	Prospectiva del Sector Eléctrico 2005-14, (2005)
Nicaragua	Prospectiva Energética LCR, OLADE (2006)
Panama	Plan de Expansión del Sistema Interconectado Nacional 2006-20, (2006)
Paraguay	Prospectiva Energética LCR, OLADE (2006)
Peru	Plan Referencial de Electricidad 2005-14, (2005)
Uruguay	Prospectiva Energética LCR, OLADE (2006)
Venezuela, R.B. de	Plan Estratégico de CVG Edelca 2007-11 (2006) and Development Plan of the Electricity Sector of Venezuela, Palmero, 2006

The region is projecting an annual rate of growth of demand of 4.8 percent for the next 10 years. Three electricity demand scenarios are usually considered in the expansion plans: low, base and high. A base scenario was used to assess the future investment needs in the region. The demand projections of individual countries in the region were aggregated by subregions, and compared to the historic rate of growth during the reform period (Table 2.2). In the subregions that experienced an economic downturn (Southern Cone in the early 2000s and the Andean region in the late 90s), the projected annual rate of growth of demand for 2005-15 resume the higher rates of growth of the early 90s.

The generation expansion plans assume that international fuel prices will remain high during the planning period. The proposed generation expansion plans should meet projected electricity demand, at least economic, financial and environmental costs. The investment and operation costs of the generation alternatives in each country reflect the cost estimates for the particular conditions of the country: technical and economic studies of hydroelectric, geothermal projects and other site-specific generation sources; market costs for thermoelectric plants; local prices for nontradable fuels; and projected international prices for tradable fuels. Most countries used a crude oil price scenario in the range of US$50 to 60/bbl, which is consistent with price forecasts used in Energy Information Administration's (EIA´s) *Annual Energy Outlook* of 2006 (Table 2.3).

Hydropower, gas-fired CCGT and coal-fired thermal plants are competitive in many countries in the region. Table 2.4 summarizes the assumptions made in selected countries for the investment costs and fuel prices of the main generation alternatives, and also shows the levelized energy generation costs calculated for typical plant factors. We note the following:

- In almost all countries, hydroelectric generation is competitive with thermal generation at expected fuel prices. The average energy cost of hydroelectric projects in South America is low, about US$35/MWh, and competes with CCGT with natural gas prices as low as US$1.7/million British thermal units (MMBTUs) (available in Peru). In the Central American countries, the generation costs of hydroelectric projects are much higher, about US$75/MWh, but compete with oil-fired thermal generation or gas-fired based on imported CNG (Panama case);

Table 2.2: LCR Demand Projections Annual Rate of Growth

	1990-95	*1995-2000*	*2000-04*	*2005-15*
Andean Region Central	4.3%	2.3%	3.1%	3.9%
Mexico	4.5%	6.4%	5.3%	5.3%
Southern Cone	5.1%	5.1%	2.7%	4.8%
United States	6.3%	6.3%	7.4%	5.8%
Total	**4.9%**	**4.9%**	**3.6%**	**4.8%**

Source: Authors' calculations.

Table 2.3: Forecasts of World Oil Prices, 2010-30 (2004 dollars per barrel)

Forecast	*2010*	*2015*	*2020*	*2025*	*2030*
AEO 2005 (reference case)	27.18	28.97	30.88	32.95	NA
AEO 2006					
Reference	47.29	47.79	50.70	54.08	56.97
High Price	62.65	76.30	85.06	90.27	95.71
Low Price	40.29	33.78	33.99	34.44	33.73
GII	37.82	34.06	31.53	33.50	34.50
Altos	27.58	31.14	34.02	37.89	40.03
EIA (reference)	35.00	36.00	37.00	38.00	39.00
EIA (deferred investment)	41.00	43.50	46.00	49.00	52.00
PEL	47.84	47.84	49.80	50.77	NA
PIRA	44.10	49.95	63.35	NA	NA

Source: EIA Annual Energy Outlook 2006.
Note: NA = Not applicable; AOE: EIA´s Annual Energy Outlook; GII: Global Insight Inc; Altos: Altos Partners; IEA: International Energy Agency; PEL: Petroleum Economics Limited; PIRA: PIRA Energy Group.

Table 2.4: LCR Generation Costs in US$/MWh

	Plant Factor or Unit	*Brazil*	*Chile*	*Colombia*	*Peru*	*Costa Rica*	*Honduras*	*Panama*
Investment Cost, No IDC								
Hydro	US$/kW	1,200	1,070	1,100	1,100	2,050	2,428	1,534
Coal	US$/kW	1,400	1,400	1,425			1,200	1,205
CCGT	US$/kW	800	652	700	550	928		650
GT	US$/kW	500	300	495	300	571	470	400
ST-oil	US$/kW		880				880	
Diesel Engines	US$/kW						1,010	
Average Generation Cost (US$/MWh)								
Hydro	50%	39.0	31.1	35.8	35.8	63.9	74.5	44.0
Coal Steam Turbine	70%	51.6	58.3	54.7			68.6	68.7
CCGT	60%	65.1	60.8	45.8	35.3	85.1		69.9
GT	50%	72.7	85.8	53.4	35.8	108.0	141.4	75.6
Oil Steam Turbine	70%		83.6				83.6	
Diesel Engines	60%						83.6	
Marginal Generation Cost	US$/MWh	40.5	91.4	40.0	35.3	77.6		60.0
Natural Gas Price	US$/MMBTU	5.0	6.7	3.0	1.8			6.3
Fuel for GT and CCGT		NG	LNG	NG	NG	Gas Oil	Gas Oil	NG
Coal Price	US$/MMBTU	1.3	2.2	1.1			2.6	2.6
Residual Fuel Oil Price	US$/MMBTU		6.6				6.6	
Gas Oil Price	US$/MMBTU					8.6	12.9	

Source: Authors' calculations.

- Gas-fired CCGT is competitive with oil-fired thermal generation in all cases, even using regasified LNG of US$6.7 / MMBTU (in case of Chile). The price of liquid fuels is about US$6.6 / MMBTU for residual and US$12.9 / MMBTU for gas oil; and

- Coal plants with coal prices of US$70 / MMBTU or US$2.2 / MMBTU are competitive with CCGT plants in countries where the price of natural gas is higher than US$5-6 / MMBTU or those that do not have access to natural gas. In central Colombia, coal prices for power generation are low (US$1.06 / MMBTU), but coal-fired thermal plants are not competitive with CCGT using natural gas priced at US$3 / MMBTU.

The generation mix for 2015 would have important changes as compared to 2005, if the proposed generation expansion plans for 2005-15 (Figure 2.1) are implemented:

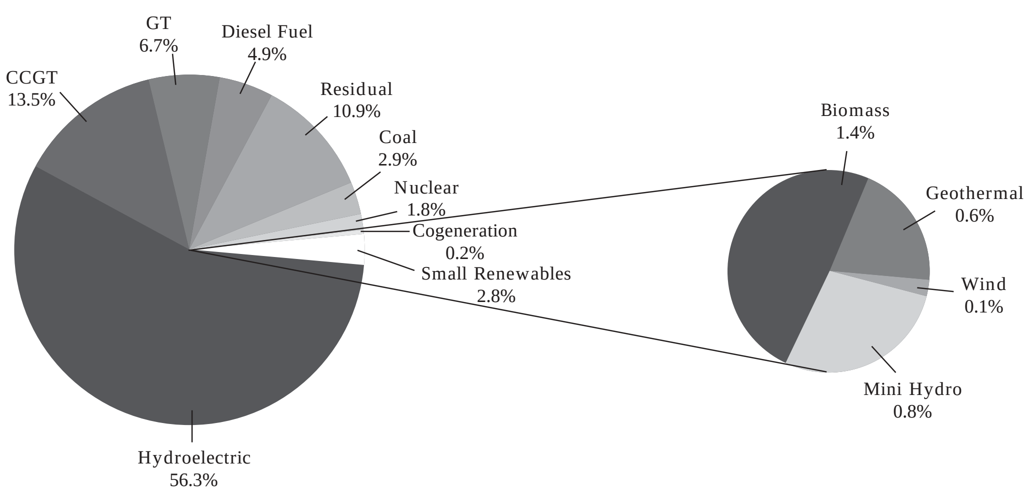
- There is a substantial increase in the participation of CCGT, from 13.6 to 16.8 percent, mainly as a result of the addition of about 22,000 MW in gas-fired CCGT capacity in Mexico and the Southern Cone (50 percent in Mexico);

- The market share of coal-fired plants increase from 2.9 to 3.7 percent mainly due to 5,700 MW of new capacity added in Chile to supply the northern region, in south Brazil, in Mexico and a few Central American countries that are considering coal as an attractive option to diversify the energy sources;

- The participation of small renewable power in the generation mix in the region, although still marginal, would have a substantial increase from 2.8 to 3.8 percent, with the addition of about 6,000 MW. This figure underestimates the participation of small renewables because the generation expansion plans in many countries did not include explicitly small renewable projects;

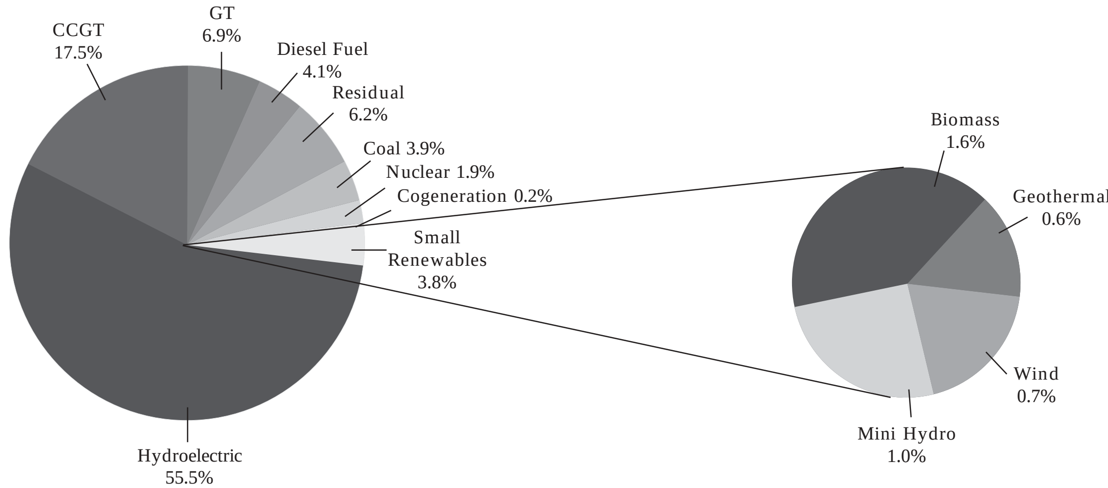
- There is a substantial decrease in the participation of oil-fired steam plants, from 10.9 to 8.3 percent as a result of the retirement of old plants in large countries, and a slight decrease in the participation of MSD engines, now that this technology is not attractive with high oil prices; and

Figure 2.1A: LCR – Installed Capacity 2005



Source: Prepared by authors based on EIA´s data in Web page.

Figure 2.1B: LCR – Installed Generation Capacity 2015



Source: Authors´ calculations.

- There is a small decrease in the participation of hydroelectric plants from 56.3 to 55.5 percent.

A net increase of about 94,000 MW of generation capacity is expected in the region from 2006 to 2015, equivalent to 39 percent of the installed capacity in 2005. About one-third of this capacity is already committed in projects under construction or already contracted to be commissioned in 2006-09, although some large hydroelectric projects currently being implemented may be commissioned as late as 2011. About 60,000 MW in projects not yet committed, included in the indicative expansion plans, would be commissioned in the period 2009-15. About 49 percent of this capacity is in hydroelectric projects and 28 percent in CCGT plants, although in the case of Mexico, there is a substantial capacity in thermoelectric projects (about 6,000 MW) with an undefined technology that could be gas-fired CCGT if reliable gas supply is ensured (Table 2.5).

The composition of the generation expansion plans varies between subregions, according to differences in demand growth, market size and resource endowment. About 61 percent of the projected generation capacity increase in 2006-15 corresponds to the Southern Cone, 19 percent to Mexico, 13 percent to the Andean countries and 6 percent to Central America. The drop in participation of the Andean countries in the installed capacity of the region (19 percent in 2005 and 13 percent of the capacity increase) just reflects a lower rate of growth of demand relative to other subregions. Looking at capacity additions by technology for the period 2009-15, the generation mix by subregions changes: the Southern Cone accounts for 80 percent of capacity additions in hydroelectric projects, due mainly to the large hydroelectric expansion program in Brazil; Mexico accounts for 35 percent of additions in conventional thermoelectric projects due to its large IPP program; and Central America accounts for 13 percent of additions in renewable power, due to the diversification policies adopted in Costa Rica and Honduras (Table 2.6).

Table 2.5: Latin America – Generation Expansion Plans Installed Capacity

	Latin America				
	2005	Committed 2006-09	New 2009-15	2015	% Increase 2005-15
Hydroelectric	136,743	14,837	31,714	183,294	34%
Conventional Thermal	99,421	15,275	26,323	141,019	42%
CCGT	32,880	8,210	16,728	57,818	76%
GT	16,173	2,818	3,758	22,749	41%
Diesel Fuel	11,889	1,547	271	13,707	15%
Residual	26,545	600	-6,571	20,574	-22%
Coal	7,039	1,400	4,300	12,739	81%
Nuclear	4,390	700	1,309	6,399	46%
Cogeneration	506	0	0	506	
Self-generation	0	0	350	350	
To be Defined	0	0	6,178	6,178	
Renewable	6,821	3,243	2,696	12,760	87%
Wind	147	1,650	656	2,453	1573%
Minihydro	1,950	1,276	0	3,226	65%
Biomass	3,339	267	1,596	5,202	56%
Geothermal	1,385	50	444	1,879	36%
Total Capacity	**242,984**	**33,355**	**60,733**	**337,072**	**39%**

Source: Authors' calculations.

About 60 new medium-sized hydro plants would have to be developed. The additional hydroelectric generation capacity planned to be commissioned in 2009-15 in new projects that are not yet under construction or contracted is about 32,000 MW, of which more than 90 percent is concentrated in about 85 projects in nine countries, and 75 percent in Brazil[13] (Table 2.7). Except for a few large projects planned in Brazil with a capacity of more than 3,000 MW (Jirau, 3,300 MW, San Antonio, 3,150 MW and Belo Monte, 5,500 MW), about 70 percent of the projects are smaller than 300 MW and about 33 percent smaller than 100 MW.

There is still a large undeveloped hydro potential in the region. In spite of a planned capacity expansion of about 46,000 MW in hydroelectric projects in 2006-15, most countries in the region, except for Brazil and Paraguay, have developed less than 38 percent of their hydroelectric potential (Table 2.7).

[13] This figure may underestimate the development of new hydroelectric projects in other countries in the region with a substantial hydro potential and which, unlike Brazil, do not have available long-term generation expansion plans with proper consideration of other hydroelectric options (for example, Argentina, Bolivia, Colombia and Venezuela).

Table 2.6: Latin America Generation Expansion Installed Capacity

		Hydroelectric	*% LCR*	*Conventional Thermal*	*% LCR*	*Renewable*	*% LCR*	***Total***	*% LCR*
Andean Countries	2005	27,916	20%	16,615	17%	412	6%	**44,943**	18%
	Committed 2006-09	3,938	27%	3,420	22%	0	0%	**7,358**	13%
	New 2009-15	2,326	7%	2,824	11%	0	0%	**5,150**	
Central America	2005	3,536	3%	4,385	4%	817	12%	**8,738**	4%
	Committed 2006-09	576	4%	576	4%	175	5%	**1,327**	6%
	New 2009-15	2,656	8%	1,414	5%	363	13%	**4,434**	
LCR	2005	136,743	100%	99,421	100%	6,821	100%	**242,986**	100%
	Committed 2006-09	14,837	100%	15,275	100%	3,243	100%	**33,357**	100%
	New 2009-15	31,714	100%	26,323	100%	2,696	100%	**60,735**	
Mexico	2005	10,530	8%	35,060	35%	962	14%	**46,552**	19%
	Committed 2006-09	754	5%	5,746	38%	135	4%	**6,635**	19%
	New 2009-15	1,500	5%	9,173	35%	506	19%	**11,179**	
Southern Cone	2005	94,761	69%	43,361	44%	4,630	68%	**142,753**	59%
	Committed 2006-09	9,569	64%	5,533	36%	2,933	90%	**18,036**	62%
	New 2009-15	25,232	80%	12,912	49%	1,827	68%	**39,972**	

Source: Authors' calculations.

Table 2.7A: LCR – Generation on Expansion Plans – New Hydroelectric Plants 2009-15

	Hydro Additions				
Country	*Total*		*Capacity per Project (MW)*		
	MW	*# Plants*	*Average*	*Minimum*	*Maximum*
Brazil	24,098	52	463	48	5,500
Chile	548	2	274	145	403
Colombia	427	2	214	27	400
Costa Rica	50	1	50	50	50
Ecuador	1,478	11	134	11	430
Honduras	631	7	90	19	173
Mexico	1,500	3	500	200	900
Panama	394	5	79	16	153
Peru	421	3	140	71	220

Source: Authors' calculations.

Table 2.7B: Largest Hydroelectric Potential in LCR (MW) % – Developed

	Potential[a/] MW	Planned Installed Capacity by 2015 MW	% Potent
Argentina	44,500	11,319	25%
Bolivia	39,850	462	1%
Brazil	143,380	101,174	71%
Chile	26,046	5,605	22%
Colombia	93,085	9,725	10%
Costa Rica	6,220	1,422	23%
Ecuador	23,467	3,535	15%
Guatemala	5,000	1,400	28%
Guyana	7,600	100	1%
Honduras	5,000	1,109	22%
Mexico	51,387	12,784	25%
Panama	3,699	1,300	35%
Paraguay	12,516	9,465	76%
Peru	61,832	3,628	6%
Venezuela, R.B. de	46,000	17,292	38%

Source: a/ OLADE estimates. SIEE Energy Statistics, October 2005.
Note: In some cases, estimates in expansion plans are much higher. For example, Brazil estimates a potential of 260,000 MW, including peak plants.

Regional Electricity Markets

The development of regional electricity interconnection projects in the region started in the 80s in the Southern Cone as a by-product of the commissioning of the large binational hydroelectric projects of Salto Grande (Argentina-Uruguay), Yacyretá (Argentina-Paraguay) and Itaipú (Brazil-Paraguay). During the past 15 years, new interconnections were completed between regions of two countries to supply firm energy (Argentina-Brazil, Brazil-Venezuela and Argentina-Chile) or to facilitate short-term energy interchanges and support in emergencies (Colombia-Venezuela, Colombia-Ecuador and Brazil-Uruguay).

The creation of competitive wholesale markets in the 90s in most countries in the region represented an opportunity to develop regional wholesale power markets based on principles of free trade: no discrimination, open access to transmission grids, free energy transactions between agents, reciprocity and common security and quality standards. Decision No. 10/98 of MERCOSUR, the treaty of 1998 to create a regional electricity market in Central America and Decision 536 of 2002 of the Andean Community adopted similar principles for the development of regional electricity markets in these subregions.

The experience of the EU and of some initiatives in the region shows that the development of a regional market is a slow process that starts with a general agreement about basic principles, and the adoption of initial directives to implement these principles and continues with reforms to tighten and adjust the directives as there is progress in the energy integration process.

Southern Cone

The attempts of Uruguay to integrate with the larger wholesale market of Argentina in the early 2000s experienced many difficulties, although the right conditions were in place: a very strong electricity interconnection (2,000 MW transmission capacity); a well-functioning wholesale market in Argentina; a new law adopted in the late 90s to implement a wholesale market with rules that were similar to those of Argentina; and the opportunity to firm up hydroelectric generation in Uruguay importing low-cost gas-fired CCGT energy from Argentina. However, the economic and energy crisis in Argentina frustrated the integration: firm energy import contracts had to be renegotiated, gas supply from Argentina was uncertain and the isolated power market of Uruguay was too small to justify the implementation of a competitive wholesale market. In spite of these difficulties, Uruguay was able to make up the energy shortfall in firm contracts, with purchases in the spot market from Argentina and Brazil. Once the physical interconnection is in place, there will be energy interchanges.

As part of a policy of diversification of energy sources, Uruguay is considering a new interconnection with Brazil that will provide an additional transfer capacity of maximum 500 MW (currently 70 MW in Rivera / Livramento). There are two options: a 500 kilo volt (kV) interconnection from Salto Grande to Garabí or a 230 kV line to Presidente Médici. The investment cost is about US$120 mn. The project could reduce generation costs in Uruguay by importing surplus hydroelectric generation in the southern region of Brazil, and importing firm power from coal-fired generation from the Candiota mines.

Central America

Central America is putting in place all the pillars for the development of a regional market (Sistema de Interconexión Eléctrica para los Países de América Central – SIEPAC project). It created the regional institutions necessary to regulate and operate the market Regional Electrical Interconnection Commission (CRIE), and Regional System Operator (EOR), ensured the financing to complete a 220 kV regional transmission grid with a transfer capacity of about 300 MW, and adopted in 2005 the regulations for the Regional Electricity Market (MER). Although the transmission line will be completed by 2009, the generation expansion plans for 2005-15 of individual countries in the region do not consider the regional market as an option for firm reliable energy supply, although about 1,000 GWh / year of short-term energy transactions took place from 1999-2005 using weak 115 kV interconnections between countries.

There are two initiatives to connect the SIEPAC project to Mexico and Colombia. A 103 kilometer (km), 400 kV, 200 MW transfer capacity, transmission line between Mexico and Guatemala, financed by the IADB, started construction in 2006 and would be completed by 2008. A 600 km, 300 MW transfer capacity, US$200 mn, Direct Current (DC) transmission line between Colombia and Panama is being studied at feasibility level. According to Colombian generation expansion plan 2006-20 estimates, based on projected generation costs and the simulation of the operation of the regional market, Colombia could export about 200 GWh / month (270 MW average) to Central America after 2010.

Andean Countries

Colombia-Ecuador. A 212 km, 230 kV transmission line, with a transfer capacity of 250 MW, between Pasto (Colombia) and Quito (Ecuador) was commissioned in 2003. Ecuador has imported about 134 GWh / month (180 MW average) in 2003-06 or about 14 percent of its energy demand from Colombia, to reduce generation costs and improve reliability of supply, at an average price of US$79 / MWh, which is much higher than the marginal generation costs in Colombia. Apparently, around 97 percent of the congestion rents have been captured by Colombia. A new 230 kV transmission line with a transfer capacity of an additional 250 MW is under construction. A concession contract for the construction and operation of a 294 km line from Betania, in Colombia, to the border with Ecuador was awarded to a Colombian municipal utility and will be commissioned by mid-2007.

Ecuador-Peru. A 107 km, 230 kV transmission line between Machala (Ecuador) and Tumbes (Peru) was commissioned in December 2004. The transfer capacity is 100 MW, but it is not possible to have a synchronous operation of the two countries due to stability problems. The line has operated in a radial arrangement to serve border areas in Ecuador. It would be necessary to install a back-to-back DC conversion station for a parallel operation, but the project is still under evaluation. Peru will be a net exporter using low generation cost gas-fired generation plants to be installed near Tumbes.

Peru-Chile-Bolivia. The generation expansion plan 2005-14 of Peru analyzed a possible interconnection (Peru-Bolivia) and concluded that it is not justified because the small differences in marginal generation costs between Peru and Bolivia do not justify the investment in the conversion station. In the case of Peru-Chile, the interconnection may be justifiable when natural gas is available in southern Peru near to the border.

Climate Change and Clean Energy

The addition of GHG emissions at current rates is not environmentally sustainable as it would have long-term effects that involve major and irreversible changes on global climate. Strong actions to develop and implement low-carbon technologies and policies are necessary in order to stabilize the stock of GHG emissions and reverse the trend (Stern review on the economics of climate change). Power generation currently produces about 24 percent of global GHG emissions and, therefore, it is a priority to decarbonize electricity production by developing renewable power, improving end use EE, use natural gas for power generation and adopt high-efficiency technologies for oil- and coal-fired thermal generation. New financial instruments are being considered by the International Financial Institutions (IFIs) to accelerate investments in clean energy (The World Bank, 2006).

The energy diversification policy that has been adopted in many countries in LCR, based on the development of RE, implementation of EE programs, expanded use of natural gas and development of regional energy markets, is the key element for transition to a low-carbon economy. Most countries in the region have a substantial underdeveloped potential of hydroelectric resources and small renewable resources, and a large potential for improving end use EE and reducing energy consumption. There is also a potential to develop regional electricity and gas markets by strengthening and expanding regional interconnection grids.

Table 2.8 shows the carbon dioxide (CO_2) emission factors in tons (t) per GWh of several thermal generation technologies using different fossil fuels. We note that:

- The use of clean fuels and high-efficiency generation plants has a substantial impact on GHG emissions. A high-efficiency CCGT, using clean natural gas, produces less than half CO_2 emissions per GWh than a new Atmospheric Fluidized Bed Combustion (AFBC) coal-fired generation plant; and
- An inefficient Open Cycle Gas Turbine (OCGT) using clean natural gas produces about the same emissions as an efficient MSD using residual fuel oil.

Despite the participation of clean power (medium and large hydro, gas-fired thermal plants and small renewable power) in total generation capacity in the region, GHG emissions are very

Table 2.8: Thermal Generation GHG Emissions

Fuel	CO_2 Emission Factor (fuel)[a/] tCO$_2$/TJ	Technology	Heat Rate TJ/GWh	Efficiency %	CO_2 Emission Factor (generation) tCO$_2$/GWh
Residual Fuel Oil	77.4	MSD	8.6	42%	666
Residual Fuel Oil	77.4	ST	10.0	36%	774
Diesel Oil	74.1	CCGT	7.8	46%	580
Natural Gas	56.1	GT	11.5	31%	644
Natural Gas	56.1	CCGT	7.8	46%	439
Coal (Cerrejon)	94.6	AFBC	9.5	38%	896

Source: a/ 2006 IPCC Guidelines for National Greenhouse Inventories (default values).

high as compared to developed countries, and will continue to increase in 2006-15. The proposed generation expansion plans for 2006-15 increase the participation of clean power from 72.8 to 73.8 percent. However, GHG emissions of power generation will continue to grow in this period at a high rate because electricity demand would increase about 60 percent in this period (4.8 percent annual rate of growth) and the initial emission factors (t/GWh) are very low in most countries in the region with hydro-based generation systems.

Table 2.9 shows the total annual CO_2 emissions of power generation in 2005 and 2014 for a selected group of LCR countries. We note that:

- In all cases, except for Mexico, total CO_2 annual emissions will increase from 100 to 200 percent during this period. In Brazil, Costa Rica, Colombia and Peru, hydroelectric generation in 2005 was about 80 percent of the total generation (the installed thermal capacity in Peru and Colombia in 2005 was substantial but was used mainly as reserve capacity). In all these countries, thermal generation will have a substantial incremental increase during this period, although it will still not become dominant. On the other hand, in Mexico, thermal generation dominates, and the substitution of high-efficiency gas-fired CCGT for low-efficiency oil-fired steam turbines will have a substantial impact in reducing emissions on a per kWh basis;

- Brazil and Costa Rica, where hydroelectric generation is dominant, have the lowest CO_2 emissions factors per total generation (less than 120 t/GWh), while Mexico produces 525 t/GWh (it will be reduced to 450 t/GWh at the end of the period); and

Table 2.9: Generation Expansion Plans CO_2 Emissions

	Peru	*Brazil*	*Mexico*	*Colombia*	*Costa Rica*
CO_2 Emissions (mn tons/year) [a/]					
2005	2.2	12.0	109.1	5.0	0.3
2014	6.3	38.0	157.0	11.0	1.5
Total Generation (GWh/year)					
2005	23,077	405,947	207,675	48,829	8,192
2014	36,059	618,584	349,126	65,774	12,906
CO_2 Emission Factor (t/total GWh)					
2005	94	30	525	102	33
2014	174	61	450	167	113
Thermal Capacity (%)					
2005	48%	18%	72%	33%	20%
2014	57%	18%	75%	33%	30%

Source: a/generation expansion plans.

- In Brazil, the coal power plants that represent 10 percent of the installed capacity in conventional thermal generation, will contribute about 30 percent of the total CO_2 emissions by 2014 due to two factors: a much higher emission factor and an expected base load dispatch (low variable generation costs).

There will be a substantial demand for carbon finance in the region. About 46 GW in medium and large hydroelectric projects and 6 GW in renewable power will be added in 2006-15. Assuming that 30 percent of this generation is eligible for carbon finance (complies with the additionality principle of the Clean Development Mechanism [CDM]), this would represent a reduction of CO_2 emissions of about 30 mn t / year with respect to the base case.

The diversification of energy sources using coal-fired generation, an attractive option in countries which do not have access to low price natural gas, may be questioned on the grounds that it does not comply with a clean energy policy. However, it could be justifiable if coal is a generation option of least-cost, low-risk and effective to reduce the vulnerability of power generation to external shocks. In this case, the important point is to select clean coal and high-efficiency technologies that minimize GHG emissions.

Investment and Financing Needs

With the implementation of competitive wholesale markets, the generation expansion plans are only a reference for investors, and usually do not include detailed estimates of investment needs. Hence, most of the available expansion plans are indicative and do not include an investment program. The investment needs in generation in the region were estimated based on the capacity additions by technology and typical unit investment costs for each technology according to information provided in the expansion plans. Investment needs in T&D were estimated as a percentage of investment in generation. In only a few cases, the expansion plans include transmission investment estimates (Brazil, Mexico, Peru and Ecuador). Investments plans in distribution are short-term by nature and are not available now that many Discoms have been privatized.

Generation investment needs were estimated for new projects to be commissioned approximately in 2009-15, and which are not under construction nor already financed. There are some large projects that will be commissioned after 2009, and are excluded because they are under construction (for example, Porce III, a 660 MW hydro plant in Colombia, and Tocoma, a 2,160 MW hydro plant in Venezuela), a development that will reduce investment needs in 2009-15 for the Andean region.

The total generation investment in the region is about US$72 bn or about US$85 bn including Interest During Construction (IDC); 60 percent in hydroelectric projects, 35 percent in conventional thermoelectric and 5 percent in renewables (Table 2.10). About 82 percent of the investment is concentrated in the Southern Cone and Mexico, and only about 7 percent in the Andean region, which can be explained by the fact that in this region: (i) the projected

Table 2.10: Latin America Estimated Generation Investment 2009-15

	LCR				Southern Cone			Andean Region			Central America			Mexico		
Generation Project	Capacity 2009-15	Investment Base	Investment (with IDC)	Unit Cost	Capacity 2009-15	Investment (with IDC)	Unit Cost	Capacity 2009-15	Investment (with IDC)	Unit Cost	Capacity 2009-15	Investment (with IDC)	Unit Cost	Capacity 2009-15	Investment (with IDC)	Unit Cost
	MW	US$mn		US$/kW	MW	US$ mn	US$/kW	MW	US$mn	US$/kW	MW	US$ mn	US$/kW	MW	US$ mn	US$/kW
Hydroelectric	31,714	41,282	50,126	1,581	25,232	36,765	1,457	2,326	3,106	1,336	2,656	6,612	2,489	1,500	3,643	2,428
Conventional Thermal	33,874	27,045	30,606	904	13,835	15,406	1,114	3,936	2,312	587	1,822	2,059	1,130	14,281	10,829	758
Coal	4,300	5,870	6,958	1,618	3,350	5,559	1,659	200	332	1,659	750	1,067	1,422	0	0	
CCGT	16,728	11,710	12,941	774	8,648	6,690	774	1,035	801	774	610	472	774	6,435	4,978	774
Renewable	2,696	3,686	4,195	1,556	1,827	2,418	1,323	0	0		363	938	2,585	506	839	1,658
Total	**68,284**	**72,013**	**84,926**	**1,244**	**40,894**	**54,589**	**1,335**	**6,262**	**5,418**	**865**	**4,841**	**9,609**	**1,985**	**16,287**	**15,310**	**940**

Source: Authors' calculations.

growth of demand is low; (ii) about 85 percent of generation expansion for 2006-14 in Venezuela has already been committed; and (iii) unit investment costs are lower than in other subregions due to reliance on gas turbines (GTs) in Peru (low cost of natural gas) and low-cost hydroelectric options.

Investments per installed kW vary according to technology, size and the subregion (Table 2.10). For hydroelectric projects, these costs vary from about US$1,300 / kW (including IDC) in the Andean countries to about US$2,500 / kW in Central America. For conventional thermal generation, they vary from US$1,100 / kW in the Southern Cone (a combination of coal-fired and CCGT) to US$587 / kW in the Andean subregion (a combination of GTs and CCGT).

An annual investment of about US$20 bn will be required in 2009-26 for generation, and T&D expansion, which is consistent with ballpark figures presented in other documents (Herz, 2006 and International Energy Agency [IEA], 2004). By pure coincidence, the estimated annual investment in generation in the region of US$11.1 bn is about the same in all cases, although the cost assumptions and methodologies may differ, and there is an inconsistent treatment for the Caribbean (Herz estimates some of the major island States). Investments in T&D show significant differences, because of the investment structure that was used. While Herz assumes 60 percent generation, 10 percent transmission and 30 percent distribution, we used 55 percent generation and 15 percent transmission, to reflect transmission investment information available from Mexico and Brazil. However, the total annual investment in the region is about US$20 bn in both cases (Table 2.11).

Most countries in the region are relying on private participation to finance a substantial portion of this investment, with differences in the scope and type of participation. Countries with a substantial private participation expect that the private Discoms will generate enough cash to finance new investment in distribution, and that private generators will continue

Table 2.11: LCR – Electricity Sector Investment Needs (US$ billion)

	Herz et al., [a/]		*IEA* [a/]		*This Report*	
	Total	*Annual Average*	*Total*	*Annual Average*	*Total* [b/]	*Annual Average*
Generation	129.9	11.8	111.0	11.1	72.0	11.1
Transmission	21.1	1.9	41.0	4.1	19.6	3.0
Distribution	64.9	5.9	89.0	8.9	39.3	6.0
Total	**215.9**	**19.6**	**241.0**	**24.1**	**130.9**	**20.1**
Period	2005-15		2011-20		2009-15	

Source: a/ Herz, 2006 and World Energy Investment Outlook, IEA, 2004.
b/ T&D investments were estimated based on the following investment structure: 55% generation, 15% transmission and 30% distribution.

investing in new generation. Most countries that maintain vertically integrated monopolies (Mexico, Costa Rica and Honduras), are promoting private participation in generation projects. Comision Federal de Electricidad's (CFE's) investment plan in Mexico assumes that IPPs would develop about 35 percent of the required investment in generation. Costa Rica expects a continuation of private investment in small renewable projects. Honduras expects that IPPs will continue developing most new generation projects, although with difficulties of implementing a generation diversification policy with a substantial participation of medium-sized hydroelectric projects may prove to be too risky for the private sector.

Countries with wholesale markets and with a substantial presence of SOEs (Brazil and Colombia) in generation rely on an active participation of SOE companies in the development of new hydroelectric plants. In Brazil, the developers of new generation plants, required to meet the projected demand of the regulated sector, are selected in competitive bids with the participation of qualified companies, mainly SOEs in partnership with private developers. In Colombia, new hydroelectric projects are being developed by SOEs, while the private companies operating in the country are holding up new generation projects because they consider that the remuneration of generation plants in the wholesale market is too uncertain to provide comfort to their lenders.

A substantial effort is required to mobilize the required financing. Annual investment needs for 2009-15 were compared with the level of private investment during the reform process to give an idea of the effort that is required (Table 2.12). The private investment that was mobilized on an annual basis during the reform period was about US$8 bn or 39 percent of the total annual investment required. If we exclude the private investment in divestiture of government assets that was not capitalized in the distribution or generation companies, the funds that were allocated to finance new investment would be less than US$4 bn, only 20 percent of the investment needs for the period 2009-15.

Oil and Gas Plans and Projects

LNG Markets, Prices and its Potential in LCR

BACKGROUND

The LNG business is in the middle of its most challenging and expansive phase since its start some 40 years ago. This is being driven by several factors:

- Reductions in the cost of LNG production and shipping;
- The ability to transport, economically, large volumes of LNG by sea over distances that would be too costly for pipelines or technically not feasible – generally, for distances greater than 2,500-3,000 miles;

Table 2.12: Annual Investment Needs 2009-15 Versus Private Participation 1990-2005 US$ Million

		Generation	Transmission	Distribution	Total
Andean Region	Investment 2006-15	708	193	386	**1,287**
	Private Partnership 1990-2005	709	52	331	**1,092**
	%	100%	27%	86%	**85%**
Central America	Investment 2006-15	1,256	342	685	**2,283**
	Private Partnership 1990-2005	397	0	205	**602**
	%	32%	0%	30%	**26%**
Latin America	Investment 2006-15	11,099	3,027	6,054	**20,179**
	Private Partnership 1990-2005	4,277	439	3,216	**7,933**
	%	39%	15%	53%	**39%**
Mexico	Investment 2006-15	2,001	546	1,091	**3,638**
	Private Partnership 1990-2005	811	0	0	**811**
	%	41%	0%	0%	**22%**
Southern Cone	Investment 2009-15	7,134	1,946	3,891	**12,971**
	Private Partnership 1990-2005	2,361	388	2,680	**5,428**
	%	33%	20%	69%	**42%**

Source: Authors´calculations.
Note: PP / 1990-2005 corresponds to the annual average of private investment according to the PPI database, averaging over the number of years after private participation started: Southern Cone: 14 years, Andean Region:10 years and CA and Mexico: 8 years.

- The desire of gas producers to monetize their gas resources – because of the scale required for LNG production, this option presents one of the biggest “bangs for the buck”;
- The abundance of natural gas resources and potential supplies that are increasingly distant from major markets;
- The development of CCGT, preferably fueled by natural gas, characterized by low investment costs and more efficient generation which has accelerated the demand for natural gas globally; and
- More stringent environmental standards regarding nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) emissions and increasing concerns about climate change have spurred the substitution of natural gas for other fossil fuels.

The structure of the LNG market impacts current and future LNG trade. This has been characterized by different pricing mechanisms and the relative importance of LNG in the importing country’s overall supply of natural gas.

MARKETS IN THE ATLANTIC AND PACIFIC BASINS

The LNG trade in the Pacific[14] and Atlantic[15] Basins has had different origins and has been characterized by different import volumes, pricing regimes and contracts. In 2004, India became the fourth country in the Asia[16] region to import LNG. The Pacific Basin market has two distinguishing features. First, the three countries have virtually no domestic gas production and no pipeline sources of natural gas imports. Hence, LNG imports supply virtually the entire gas market. Second, LNG imports increased rapidly in the 80s and early 90s, primarily driven by security of supply concerns, and the need to seek alternatives to oil while price was a less important consideration.

In the European market, LNG imports meet about 25 percent of the gas demand, with the remainder being met by indigenous supply and imported pipeline gas. In contrast, in the U.S. market, domestic gas supply and imported pipeline gas satisfies about 98 percent of the demand with imported LNG covering only the remaining 2 percent. LNG's share in the U.S. gas market is expected to rise in the future, but whether it would exceed about 8 percent remains to be seen, as this depends on the scale of pipeline imports from Canada and Alaska, as well as the role of an expanded nuclear power program. The euphoria about U.S. demand for LNG in the future has declined in the past year, due to the high prices of gas relative to coal. British Petroleum (BP) and Exxon / Mobil both cancelled separate plans to develop LNG import terminals in the Gulf of Mexico on concerns of overcapacity and rising costs. The only other countries in the Americas to import LNG in 2005 were the Dominican Republic and Puerto Rico. In both cases, the gas is dedicated to power generation and constitutes the only source of gas in these islands – however, these imports only accounted for about 5 percent of that of the Americas.

Figure 2.2 illustrates the growth in LNG trade in the different regions from 1993-2005. The Asia region accounting for 66 percent of the global trade of 6,795 billion cubic feet (bcf) (140 mn t) in 2005, a slight decrease over the past decade from 75 percent in 1993. As the LNG market has expanded, some flexibility has emerged in regard to shipping and contracts being negotiated for shorter durations.

LNG PRICING IN THE DIFFERENT ZONES

Historically, LNG prices have been higher in the Pacific than the Atlantic Basin. During the 90s, they averaged about US$4 / MMBTU in the former and US$3 / MMBTU in the latter. LNG prices are benchmarked usually to its competing fuels, with the three different and rather independent markets possessing their own pricing structures.

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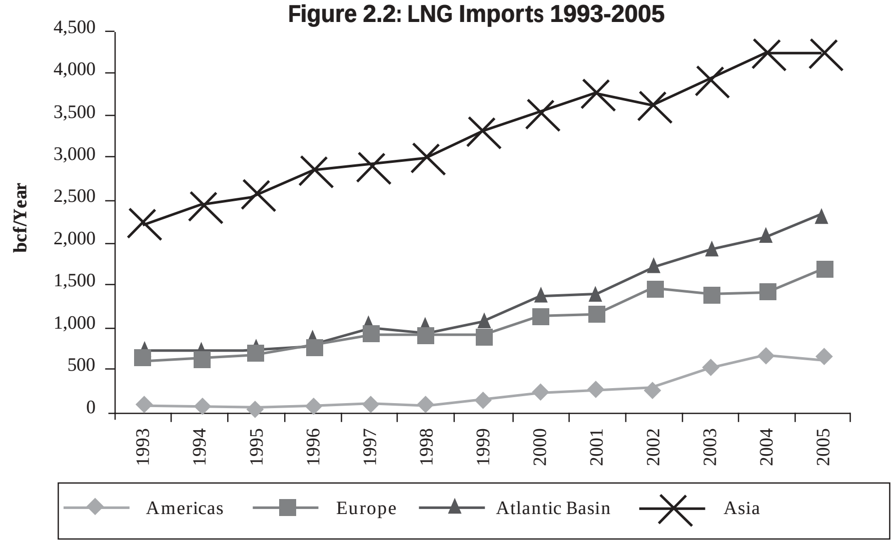
[14] Pacific Basin includes Japan, the Republic of Korea and Taiwan (China).
[15] Atlantic Basin includes the Americas (the United States, Puerto Rico and the Dominican Republic) and Europe (Belgium, France, Greece, Italy, Portugal, Spain, Turkey and U.K.).
[16] Asia region includes the Pacific Basin and India.

Figure 2.2: LNG Imports 1993-2005



Source: ERG Consultancy – 2003 World LNG Inductry Review.

In the U.S., the competing fuel is pipeline natural gas and the benchmark price is either a specified market in long-term contracts (for example, the New England market which is a high-cost market) or the Henry Hub price for short-term sales. Both LNG importers and exporters are exposed to a significant level of risk due to the high price volatility of U.S. natural gas markets. The Dominican Republic and Puerto Rico are, at present, the only LNG importers other than the U.S. in the Americas. LNG importers in these countries, both IPP operators, have their prices benchmarked to Henry Hub. It is difficult to envisage that any LNG importer in the Caribbean Basin or the Gulf of Mexico would be able to source LNG from suppliers willing to sell its product into the Basin at prices not indexed to Henry Hub. This has important implications for the small markets of the Non Oil Producing (NOP) countries, casting doubts on the competitiveness of LNG for baseload power generation. It is equally difficult to envisage how importers in these smaller markets, in which LNG would be the sole source of natural gas, would not insist that such imports be indexed, at least, to the fuel displaced, that is, residual fuel oil. For example, in the Spanish market, the competing fuel has traditionally been low-sulfur residual fuel oil. This benchmark has been one of the reasons why European LNG imports have lower cost than those of both the United States and the Pacific Basin countries. However, in the northern European markets, LNG is now starting to be linked to natural gas spot and futures market prices. In contrast, in the Pacific Basin countries, as there is no indigenous or imported pipeline natural gas, LNG prices have been linked traditionally to a basket of crude oils.

RELATIONSHIP BETWEEN CRUDE OIL AND U.S. NATURAL GAS PRICES

A recent study[17] has analyzed the relationship between U.S. natural gas and crude oil prices, as measured by the prices of Henry Hub natural gas and those of WTI crude oil

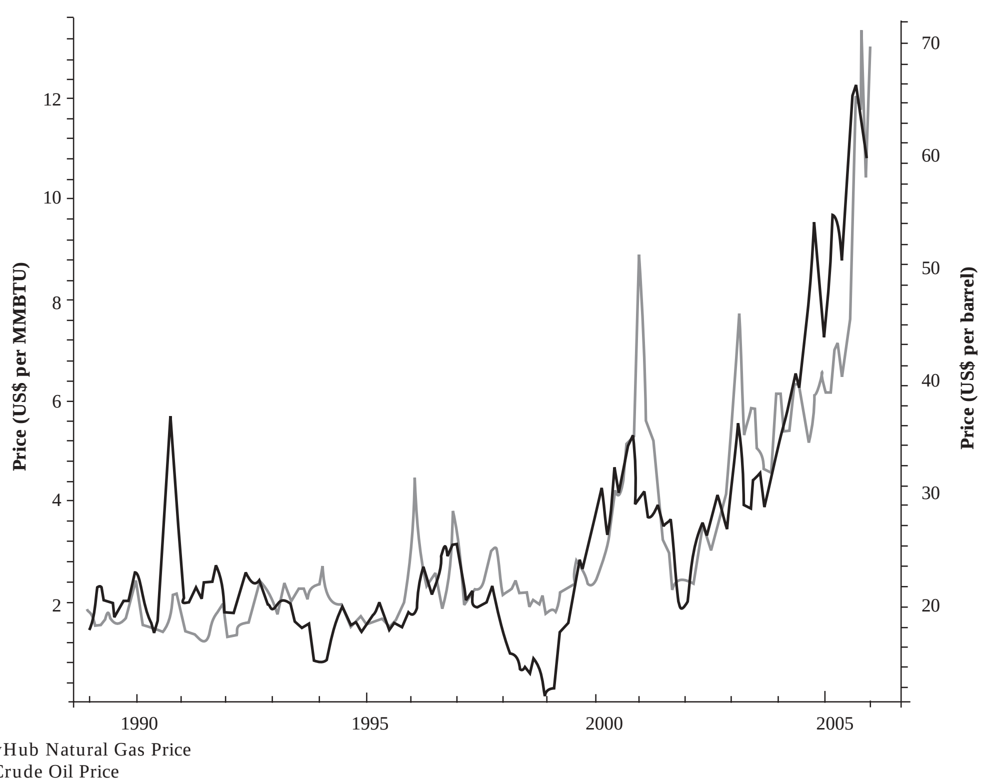
[17] *"The Relationship between Crude Oil and Natural Gas Prices,"* by Jose Villar and Frederick Joutz, Energy Information Administration, Office of Oil and Gas, October 2006.

over the period 1989-2005. The movement of the WTI and Henry Hub prices shown in Figure 2.3 tends to support the economic theory that natural gas and crude oil prices should bear some form of relationship because they are substitutes in some areas of consumption and complements in production. The analysis confirms a cointegrating relationship between the WTI and Henry Hub time series, with significant statistical evidence that WTI crude oil and Henry Hub gas prices have a long-run cointegrating relationship. A key finding is that natural gas and crude oil historically have had a stable relationship, despite periods when they appeared to have decoupled. This decoupling occurred when Henry Hub prices rose above their historical relationship with WTI prices in 2001, 2003 and 2005. Finally, statistical evidence re-enforced the view that while oil prices influence natural gas prices, the impact of natural gas prices on oil prices is negligible. One reason being the relative size of the two markets, with the latter being determined in the world market, and the former being regionally segmented.

The Strategic Differences Between Natural Gas Sourced via Pipeline or as LNG in LCR

The Energy and Mining Sector Board issued, in April 2004, Operational Guidance for the World Bank Group staff on "Public and Private Sector Roles in the Supply of Gas

Figure 2.3: Relationship Between WTI Crude Oil and Henry Hub Gas Prices



Source: "The Relationship between Crude Oil and Natural Gas Prices," by Jose Villar and Frederick Joutz, Energy Information Administration, Office of Oil and Gas, October 2006.

Services in Developing Countries." The guidelines drew on an independent evaluation of World Bank Group activities in the extractive industries, and an independent stakeholder consultation process led by Dr. Emil Salim. One of the recommendations of special relevance to natural gas is highlighted in the Operational Guidance (Paragraph 42), that states, among others:

"The World Bank Group lending should concentrate on aggressively promoting the transition to renewable energy and endorsing natural gas as a bridging fuel – building new pipelines and renovating leaking ones and funding fuel-switching from coal to gas in power generation."

Setting aside the somewhat evangelical flavor of the recommendation, it fails to distinguish between natural gas sourced via pipeline from LNG, which is especially pertinent in LCR, with its extensive natural gas resources and quite significant gas pipeline networks in its major economies, as distinct from other emerging markets such as India and China. Additionally, the carte blanche substitution of gas for coal in the power sector is too sweeping since in many markets, both large and small, baseload power generation fueled by coal has lower economic costs and risks than that fueled by LNG indexed to crude oil.

In the LCR context, differentiating between the following gas supply arrangements needs to be kept to the fore:

- Natural gas delivered by pipeline, whether it is indigenous or imported from a neighboring country with gas surplus;
- Imported LNG into a large gas market such as Mexico; and
- LNG going into a relatively small market where it is the only source of gas, typical of the Central American and larger Caribbean markets.

In cases of gas delivered by pipeline, whether indigenous or imported from a neighboring country, prices are determined, generally, on a cost-plus basis ensuring attractive economic returns commensurate with the different risks of the gas producer and the transporter, while safeguarding these returns against inflation. This is the case when the "gas market" in the importing country is a "gas product supply market" with few buyers and sellers, and limited T&D systems, unlike where there is a "gas commodity supply market" as in the United States and Canada. Even recognizing that some level of additional economic rent may also be extracted by the producer, pipeline gas is less susceptible to "commoditization" and arbitrage than LNG. This is due, in part, to the pipeline's physical inflexibility to change the destination of its product, unlike a LNG tanker which can redirect its cargo while on the high seas. This implies that in the gas markets prevailing in LCR, in the absence of political intervention, pipeline gas is likely to be supplied at lower prices and subject to lower price volatility than imported LNG.

In essence, in those countries where both pipeline gas and LNG exist, the issue becomes one of balancing the potential benefits and risks associated with each supply mode. The two potential benefits of LNG imports are:

- Greater gas supply options – an issue of special relevance to Chile following the reduction in Argentine gas exports; and
- Limited cross-border issues.

However, these benefits have to be balanced against two significant risks (noted in Chile's Country Assistance Strategy):

- A higher and more volatile "commoditized" gas price; and
- A supply price driven by other geographically unconnected markets.

The benefits of pipeline gas include:

- A lower and less volatile gas price; and
- Limited competition for gas supply from other markets.

These benefits are weighed against the following risks:

- Dependence on one supplier – to ameliorate this would require extending existing pipeline networks to include other suppliers, such as Peru, as envisaged through the deepening and re-enforcement of the Southern Cone gas network, discussed below; and
- Cross-border issues – which have surfaced in the recent dispute between Bolivia and Brazil following the nationalization of Petrobras' assets in Bolivia.

Fuels' Competition for Baseload Thermal Power Generation

With the exception of few LCR countries still endowed with significant underdeveloped hydro resources, the electricity sector remains the major market for natural gas. As such, the competition for baseload generation between the alternative fuels will be the factor determining what role natural gas would play in the electricity sector over the next several years. Figure 2.4 shows the evolution of the prices between 2000 and June 2006 of:

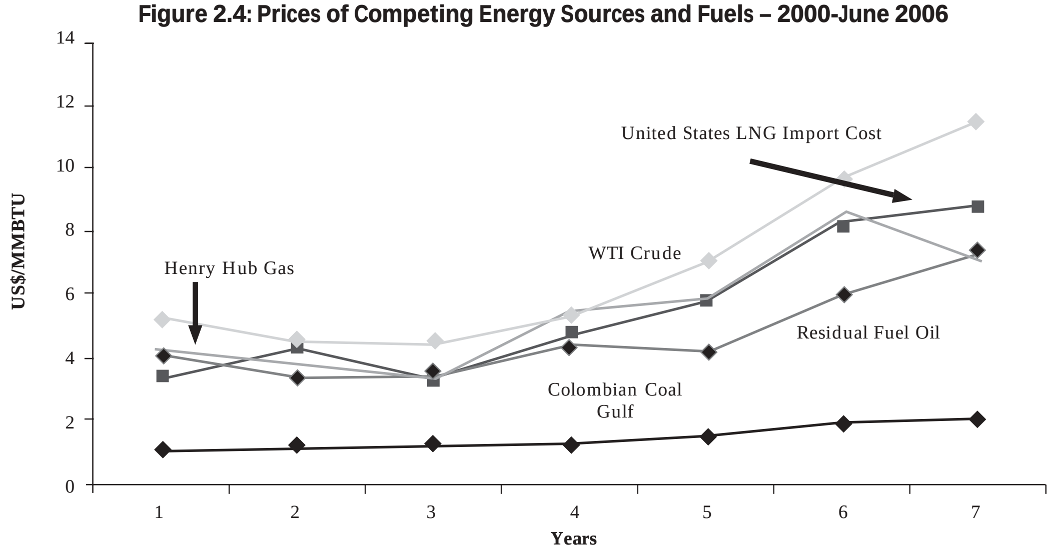
- Low-sulfur Colombian coal landed in the Gulf of Mexico;
- Henry Hub natural gas;
- WTI crude oil;

- One percent sulfur residual fuel oil Gulf of Mexico; and
- Landed cost of LNG in the United States.

It dramatically illustrates two very different trends during the period in question. First, the complete decoupling of the evolution of Colombian Gulf of Mexico coal prices compared to those of crude oil and its product (residual fuel oil). Second, the extent to which the prices of Henry Hub gas and Gulf of Mexico 1 percent sulfur residual fuel oil are correlated with the WTI crude oil price, the main difference being their differentials relative to WTI.

Table 2.13[18] shows estimates of the generation costs of 300 MW grid-based generation units based on four technologies. Three of the technologies are conventional: a residual fuel oil-fired steam unit; a gas-fueled CCGT; and a pulverized-coal steam unit with $DeNO_x$ and $DeSO_x$ controls operating at SubCritical steam conditions. The new technology is the Integrated Gasification Combined Cycle (IGCC), one of the 'clean coal' technologies being developed with a few plants in operation in the United States and Europe.

Figure 2.4: Prices of Competing Energy Sources and Fuels – 2000-June 2006



Source: EIA, DOE Import Prices of Colombian Coal, LNG and Residual Fuel Oil; Henry Hub Gas Prices and WTI Prices Web pages 2000-June 2006.

Table 2.13: 2005 Estimates of Thermal Generating Costs (US¢/kWh) for 300 MW Units for Competing Fuels

Technology	*Capital Cost*	*Fixed O&M*	*Variable O&M*	*Fuel Cost*	***Total Cost***
Residual Oil Steam	1.27	0.35	0.30	5.32	**7.24**
CCGT Gas	0.95	0.10	0.40	4.12	**5.57**
Coal-steam SubCritical	1.76	0.38	0.36	1.97	**4.47**
Coal IGCC	2.49	0.90	0.21	1.79	**5.39**

Source: Technical and Economic Assessment of Off-grid, Mini-grid and Grid Electrification Technologies, Summary Report, Table 40, September 2006.

[18] *Technical and Economic Assessment of Off-grid, Mini-grid and Grid Electrification Technologies*, Summary Report, Table 40, ESMAP Technical Report 121/07, December 2007.

The fuel costs assumed in Table 2.13 are US$6.4 / MMBTU, US$6.1 / MMBTU and US$2.4 / MMBTU for 1 percent sulfur residual fuel oil, natural gas and steam coal, respectively. What is significant is that the natural gas price has to be about US$4.5 / MMBTU (some 25 percent lower) for the generation costs of the CCGT to break even with that of the coal unit. While the prices of natural gas delivered by pipeline in either the Southern Cone or in gas-endowed countries would be lower than US$4.5 / MMBTU, this is not the case with imported LNG, unless the WTI crude oil price declines to about US$30 / bbl.

Figure 1.18 (Chapter 1) illustrates the generating costs for the four technology options considered here and highlights clearly the narrow “uncertainty band” associated with the coal options relative to those of oil or natural gas-fired plants, due primarily to much lower price uncertainty.

This analysis highlights the issue that many of the smaller nonoil / gas-endowed countries, as well as the World Bank Group, will face as it becomes apparent that the least-cost and least-risk baseload thermal generation option could be coal. Given its higher investment cost and longer construction periods, IPP investors may not be rushing in to build such plants and, therefore, the public sector would have to take the lead in assuring its place in the generation mix if a least-cost expansion is desired. If the climate change perspective is to override the least-cost objective, significant incentives would be needed to go the LNG way. Such incentives would have to compensate for future variations in the differential between coal and LNG prices; otherwise, small systems would be penalized unfairly.

Potential Role of LNG in LCR

LNG’s role in LCR has to be viewed from two very different perspectives. First, from that of exporting LNG into the world market similar to the niche that Trinidad and Tobago has developed over the past seven years in which LNG exports have increased to an estimated 2.2 billion cubic feet per day (bcfd) in 2006, making it the largest LNG exporter in the western hemisphere. Second, from that of importing LNG to meet the gas demand in the region.

Given the current state of the global LNG market, LNG exports yield some of the highest gas netback values. This is an option available to countries with significant gas resources relative to the potential demand of their domestic markets. From a purely resource base standpoint, Venezuela and Bolivia (once the issue of access to the Pacific coast is resolved) are the two countries best positioned to enter this market. With abundant and low-cost natural gas resources, the potential role of LNG in meeting the gas demand in LCR is seen primarily within a “gap-filling” context in the large countries where the issues would be getting gas into:

- Areas in which its delivery by pipeline is uneconomic due to the significant distances from the existing networks, such as, in northern Brazil; or
- Areas where concerns about the security of pipeline-delivered gas have become important, such as in Chile and Brazil; or

- Mexico, the largest gas market in LCR, where the desire to diversify its current gas imports, which satisfy currently about 18 percent of gas demand, would be of relevance.

As noted earlier, the only markets in the Americas other than the United States in which LNG is imported, are the Dominican Republic and Puerto Rico. Both of these are small markets with neither indigenous gas nor access to pipeline gas supply. LNG, therefore, represents the sole source of gas and its price sets the national price of gas. With their LNG prices being indexed to Henry Hub, these importers have experienced significant increases in their gas costs over the past three years. In the case of the Dominican Republic, no doubt, this exacerbated the financial pressures on the power sector. There is an important lesson to be learned here in terms of the need to diversify the fuel mix in thermal generation capacity to limit the system's exposure to fuels not decoupled from global oil price movements. This implies that the role of coal in baseload generation needs to be more closely assessed. This would be also of relevance in the Central American and Jamaican markets.

Development of Cross-border Gas Pipeline Networks

INTEGRATION OF THE SOUTHERN CONE GAS PIPELINE NETWORKS

The gas pipeline networks linking Argentina-Uruguay; Argentina-Chile; and Santa Cruz, Bolivia-Sao Paulo, Porto Alegre and Rio de Janeiro, Brazil, currently form the backbone of the Southern Cone gas transmission system, linking the gas fields of Argentina and Bolivia to the major gas demand markets of Argentina, Brazil, Chile and Uruguay. This transmission network has more than 5,000 km of pipelines, of which the Bolivia-Brazil system exceeds 3,000 km, as illustrated in Figure 2.5.

Figure 2.5: Southern Cone: Cross-border Gas and Electricity Networks in 2004*

Source: "Analysis of Strategies for the Southern Cone Energy Sector," Mario Pereira, 2004.

Against the background of gas supply rationing in Argentina beginning in 2004, and the knock-on effects of supply reductions to Chile, the Ministers of Economy & Finance and Energy of Argentina, Brazil, Chile, Paraguay, Peru and Uruguay requested, in July 2005, the assistance of the World Bank and the IADB in designing an institutional framework to enable a viable South American Gas Pipeline project to be developed with the participation of the private sector. The IADB would focus on the framework of a protocol of basic principles between the governments as the basis for State-to-State agreements, and the World Bank would facilitate the provision of resources and the direction of the technical, economic, environmental and financial aspects of this ambitious project – Proyecto de Integración Gasífera del Cono Sur.

The core of this project is to promote increased gas trade between the exporting and importing countries, thereby enabling suppliers to monetize their gas resources while importing countries would be in a better position to reduce their dependence on the volatile imported oil market. Additionally, the environmental benefits from deeper gas penetration into the subregion would be significant in reducing CO_2 impacts.

This initiative is an opportunity to rebuild confidence in the security of cross-border gas trade and in the sanctity of contracts, and to strengthen the institutional arrangements underpinning the project. It is a significant challenge, given the planned nationalization of Petrobras' hydrocarbon assets in Bolivia, and Brazil's announcement to accelerate the development of offshore and onshore gas fields, as well as building LNG regas facilities in Rio and the North-East. This followed in the wake of Chile inviting bids to establish a LNG regas facility. These gas supply diversification measures planned by the two major gas importers in the Southern Cone reflect their concern about the risks of being overdependent on a single gas supply source.

In this context, Argentina and Bolivia are expected[19] to sign an agreement whereby Argentina's current gas imports of 270 mmcfd from Bolivia would increase to some 950 mmcfd by 2010. The objective of this increase in gas imports in such a short time horizon is to ease Argentina's energy shortages. In addition, the price of Bolivian gas to Argentina has increased in 2006 by about 40 percent, up to 5.00 / MMBTU. It is estimated that an investment in exploration and development of about US$2-3 bn would be required to boost gas exports to Argentina, as well as a further US$1.2 bn in transport since the existing pipelines are operating at full capacity. Argentina's State energy company, ENARSA, would participate in the E&P investments. However, with ENARSA's very limited investments in Argentina itself, it would be difficult to envisage the company being able to cover the scale of investments needed in Bolivia. Argentina's agreement to the US$5 / MMBTU import gas price puts pressure on Brazil, which currently pays US$4 / MMBTU and imports some 900 mmcfd of gas from Bolivia.

[19] Financial Times, Americas Section, *"Argentina Secures Big Bolivian Gas Deal,"* October 18, 2006.

Given this background, a strategy to enhance the security of gas supply in the Southern Cone depends critically on:

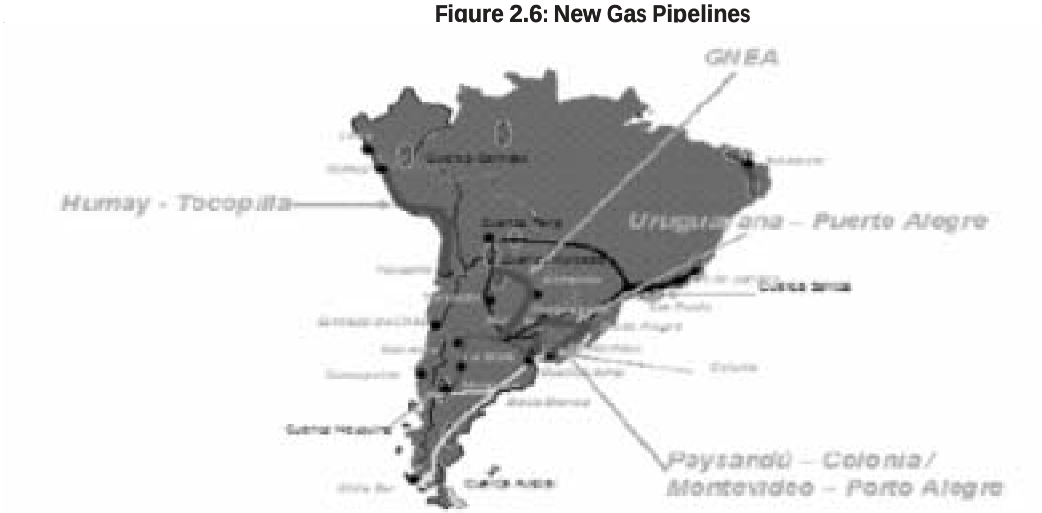
- Agreement at the State-to-State level on the basic principles governing the operation of the gas network which is characterized by different ownership structures across borders and different national regulatory regimes – a challenging task;
- The importance of separating political from commercial aspects of the cross-border trade;
- Integration of additional supply nodes into the existing gas network, in particular, Peru;
- Re-enforcement of the existing network; and
- Abiding by the sanctity of contracts.

However, if there is to be any progress, some pending issues that have to be resolved are:

- Priority be given to meeting gas demand in the national market over either export or transit gas – a challenge to be resolved between exporter and importer countries;
- The roles of governments, private and State companies;
- A supranational authority with powers to resolve disputes; and
- Management of social and environmental impacts.

Figure 2.6 shows the new gas networks proposed for the Southern Cone. It consists of the 1,356 km line from Humay to Tocopilla; the Gasoducto Noreste Argentina (GNEA) 1,500 km line from the Noreste gas field to Rosario, Argentina, via Asuncion in Paraguay; and the 615 km Uruguayana line to Porto Alegre, Brazil. The estimated gas demand scenarios are set out in Table 2.14.

Figure 2.6: New Gas Pipelines



Source: "Energy Integration - Importance of Legal Framework," FIER 2006. Eleodoro Mayorga-Alba, World Bank. September 2006.

Table 2.14: Estimated Gas Demand (mmcfd) 2009-25

Pipeline	*Volume (mmcfd 2009)*	*Volume (mmcfd 2015)*	*Volume (mmcfd 2025)*
GNEA	320	3200	4910
Uruguayana-Porto Alegre	25	245	630
Humay-Tocopilla	40	390	515

Source: "Analysis of Strategies for the Southern Cone Energy Sector," by Mario Pereira, 2004.

The estimated demand between 2015 and 2009 – a 10fold increase in six years – on the GNEA system appears extremely high for a fairly developed gas network system like Argentina's.

The characteristics of the pipeline network are shown in Table 2.15. The estimated investment costs of the three pipeline systems are shown in Table 2.16.

The major investment would be for the GNEA system, amounting initially to US$2.67 bn, while the estimated initial investment for the three systems would be US$4.19 bn, which would rise to US$6.78 bn after accounting for increased compression in the lines as gas demand rises. Roughly, 92 percent of this additional investment would be in the GNEA system.

The successful implementation of this project would require gas exporters, importers and governments to balance their individual and collective interests very carefully. While the key to maintaining the momentum in gas use is enhanced regional cross-border gas trade, it is important that the two major gas exporters, Bolivia and Peru, recognize that the cost to them of nonintegration is roughly twice the foregone benefits to the importers of gas. This is particularly relevant for Bolivia, since its only other option is that of LNG export, which raises the problem of access to the Pacific.

Table 2.15: Characteristics of the Pipeline Network

Pipeline	*Length (kms)*	*Diameter (inches)*	*Compression (HP)*
GNEA	1,500	48	680
Uruguayana-Porto Alegre	615	30	72
Humay-Tocopilla	1,356	30	90

Source: "Analysis of Strategies for the Southern Cone Energy Sector," by Mario Pereira, 2004.

Table 2.16: Estimated Investment Costs of the Three New Pipelines

Pipeline	*Initial Investment (US$ millions)*	*Final Investment (US$ millions) by 2025*
GNEA	2,670	5,050
Uruguayana-Porto Alegre	420	510
Humay-Tocopilla	1,095	1,218

Source: "Analysis of Strategies for the Southern Cone Energy Sector," by Mario Pereira, 2004.

COLOMBIA/VENEZUELA GAS PIPELINE

A 220 km natural gas pipeline is being built from eastern Colombia to the Maracaibo region in Venezuela, following agreement between Colombia and Venezuela. A pipeline with a capacity of 500 mmcfd is planned to be operational by mid-2007, at an estimated investment cost of US$335 mn. The two governments have signed a four-year contract for the export of 150 mmcfd of Colombian gas to Venezuela from mid-2007 to mid-2011, presumably to cover a regional gas deficit in western Venezuela. There would be a possibility – post-2012 – for the gas flow to be reversed, if Venezuelan supplies are available. This could provide the basis for gas to be delivered from Venezuela via Colombia through a subsea pipeline from Cartagena to Colon, Panama, post-2012. To this end, an MoU signed in July 2006 between Venezuela, Colombia and Panama agreed to extend the pipeline system to Colon, and initiate studies to this effect. This project could provide the vital opportunity of access to gas to the countries in the southern isthmus.

INTRODUCTION OF NATURAL GAS INTO CENTRAL AMERICA

The issue of natural gas entering the Central American energy supply mix has been the focus of several studies over the past decade. However, progress has been slow in realizing this objective. One of the earliest studies was sponsored by Brown & Root Inc. and undertaken by Arthur D. Little[20] in 1995. This was followed by a prefeasibility study sponsored by Comisión Económica para América Latina y el Caribe (CEPAL) in 1997,[21] as part of a collaborative effort between OLADE/CEPAL/German Agency for Technical Cooperation (Deutsche Gesellschaft für Technische Zusammenarbeit – GTZ). A third study of OLADE was completed in 2001.[22] This study confirmed the estimates of potential gas demand in 2015 of the previous studies. These estimates are shown in Table 2.17, in which demand was envisaged to increase from about 180 mmcfd in 2006 to 946 mmcfd in 2015.

The potential gas supply sources for Central America include Venezuela, Trinidad and Tobago, Mexico and Colombia. In the case of Colombia, the study concluded that gas exports, on the scale envisaged, required additional gas reserves to be proven, since proven reserves in 2000 would just about meet the expected growth in national demand up to about 2015.

Table 2.17: Projected Demand for Natural Gas in Central America (mmcfd)

Zones	*2006*	*2010*	*2015*
A	125	278	566
B	56	167	380
Total	**181**	**446**	**946**

Source: Incorporaciñon del Gas Natural en la Interconnexión Eléctrica en América Central," OLADE, June 2001.
Zone A: Northern Central America – Guatemala; El Salvador; and Honduras.
Zone B: Southern Central America – Nicaragua; Costa Rica; and Panama.

[20] Pan American Gas Pipeline, by Arthur D. Little Inc., July 1995.
[21] "*Gasoducto Regional México-Istmo Centramericano*," Summary of the Prefeasibility Study, January 1998.
[22] "*Incorporación del Gas Natural en la Interconnexión Eléctrica en América Central*," OLADE, June 2001.

Proven gas reserves are estimated at 4 Tcf with additional nonproven reserves of 2.4 Tcf. Colombia's inability to export significant volumes of gas over a sustained period was confirmed in a recent analysis by Ecopetrol.[23] This analysis noted the recent agreement between Colombia and Venezuela for Colombia to export 150 mmcfd to Venezuela for a limited four-year period, due to a gas deficit in western Venezuela, as discussed here. Ecopetrol's analysis also noted the possible export of up to 40 mmcfd of gas to Panama from July 2008-July 2018, to be used for power generation. In this case, it is envisaged that the gas would be delivered as CNG by barges using TransCanada's technology. This would be one of the first cases of the marine transport of CNG.

In the case of Mexico, gas demand increased from a large base of 4,200 mmcfd in 1999 to about 6,500 mmcfd in 2004 – an annual increase of some 9.5 percent. However, in this period, indigenous gas supply declined by about 5 percent with this demand being met through a dramatic increase in gas imports from the United States. The OLADE study concluded that without significant augmentation of gas reserves, export of gas from Mexico to Central America was not realistic. Indeed, Mexico's first priority would appear to be to address its significant gas deficit. In the period 1999-2004, reserves of associated and nonassociated gas declined by 25 percent and 14 percent, respectively. According to a recent report by the Secretaria de Energia of Mexico ("Prospectiva del Mercado de Gas Natural, 2005-14"), gas demand is expected to increase to 9,500 mmcfd by 2014, while production is stated to rise to 7,200 mmcfd (an increase of about 50 percent above the 2004 level), with about 80 percent of the supply / demand gap being met largely by LNG imports.

The other supply option assessed was Venezuela, the country with the largest oil and gas reserves in the region. The country's proven gas reserves are estimated at 146 Tcf. However, it exports no gas and, as mentioned above, is expected to import gas from Colombia for a four-year bridging period from late 2007. A significant percentage of Venezuela's gas is associated with oil. This leads to significant problems in optimizing the production of oil and gas to satisfy markets with very different market requirements. It is, therefore, unlikely that Venezuela would be able to export gas for at least the next six to eight years. However, it would appear that for gas to be delivered by pipeline to Central America, its most likely long-term source would be Venezuela routed via Colombia, unless there are significant new gas discoveries in either Colombia or Mexico.

The fourth gas supply option assessed in the study was Trinidad and Tobago. However, the delivery mode was via LNG, and not pipeline gas, given that the island has four trains of LNG now in production with about 2.2 bcfd of capacity. Further expansion of LNG production capacity will require that additional reserves be proven, and it is unlikely that there would be LNG capacity available in the existing four trains to meet any potential Guatemalan or Central American demand in the medium term.

[23] *"Oferta de Gas Natural en El País,"* Ecopetrol, September 2006.

Mexico is expected to begin importing LNG at a regasification facility at Altamira in the near future. Presumably, this reflects a gas import strategy to diversify the level of its dependence on U.S. pipeline gas imports, as reflected in the estimates of major LNG imports at other ports during the next 10 years. If this scale of LNG imports was to materialize in the medium term, it could provide a supply source for limited exports of gas to Guatemala and El Salvador by pipeline, though the issue of the price at which the gas could be delivered to these countries could be a significant constraint.

The most recent study on introducing gas into Central America was launched by the heads of State and governments of the Central American countries, Colombia, Mexico and the Dominican Republic, in the Declaration of Cancun (2005). This study, to be undertaken at the feasibility level, has the objective of developing a strategy to introduce gas into the subregion.[24] The Inter-American Development Bank (IADB), CEPAL and Fondo Multilateral de Inversiones (FOMIN) are assisting through participation in various review groups and committees overviewing the study. Without seeking to prejudge the findings of the ongoing study, the introduction of gas into Central America will, in all eventualities, have to be implemented in an incremental manner, and not through a single major pipeline project from either Mexico or Colombia. The incremental approach implies:

- Barges initially from Colombia to Panama;
- Followed eventually by a pipeline from Venezuela/Colombia up to Nicaragua for the three southern countries;
- With the three northern countries being supplied from Mexico either when its gas reserves are augmented sufficiently, or with gas from LNG imported by Mexico at Altamira; and
- The final stage of gas interconnection would occur when the northern and southern pipeline systems are connected.

It should be noted, however, that it is unlikely that any of the countries in Central America would be able to import LNG on terms any more favorable than those of the current three importers in the Americas. As such, it is unlikely that LNG, on such terms, would prove to be the least cost and risk option for baseload power sector generation in the subregion unless oil prices decrease considerably. In addition, LNG contracts have to be anchored by the creditworthiness of the offtaker. In this context, the probability is higher of LNG being accessed by the northern countries of the isthmus through LNG importation by Pemex in Mexico and then delivered by pipeline to these countries, than directly through regas facilities in the isthmus.

[24] *"Programa de Integración Energética Mesoamerican – Estudio para Definir una Strategia de Introducción del gas Natural a Centro América,"* Versión Final, May 4, 2006.

EASTERN CARIBBEAN GAS PIPELINE

In August 2002, the Prime Minister of Trinidad and Tobago announced the government's support for a natural gas pipeline to supply natural gas to the Eastern Caribbean islands of Grenada, St. Vincent, St. Lucia, Barbados, Dominica and the French Departments of Martinique and Guadeloupe. These five Caricom members import from the refinery in Trinidad, 2.7 percent sulfur bunker C fuel oil (Barbados for use in their slow speed diesel oil units) and diesel oil (in the other four islands) for their electricity generation, while Martinique and Guadeloupe import 1 percent sulfur residual fuel oil from other regional suppliers. However, in order to comply with EU regulations, the two French Departments have to import 0.3 percent S residual fuel oil from 2007-08. The price of bunker C fuel oil is about 10 percent lower than the 1 percent sulfur residual fuel oil.

A feasibility study was undertaken by Doris Engineering in 2004, which was financed by the Eastern Caribbean Gas Pipeline Company (ECGPC). The ECGPC was established in 2003 to develop, construct and operate the Eastern Caribbean Gas Pipeline (ECGP) and is a majority private sector-owned company led by two financial institutions in Trinidad and Tobago. The feasibility study found that the most economic and technically favored routing for the pipeline (from the standpoint of least seismic risk) was from Tobago to Barbados as the Phase I segment, followed by Phase II segment from Barbados to Martinique, with a 20 mile spur line to St. Lucia, and onto Guadeloupe with a spur line to Dominica. Figure 2.7 shows the routing of the pipeline.

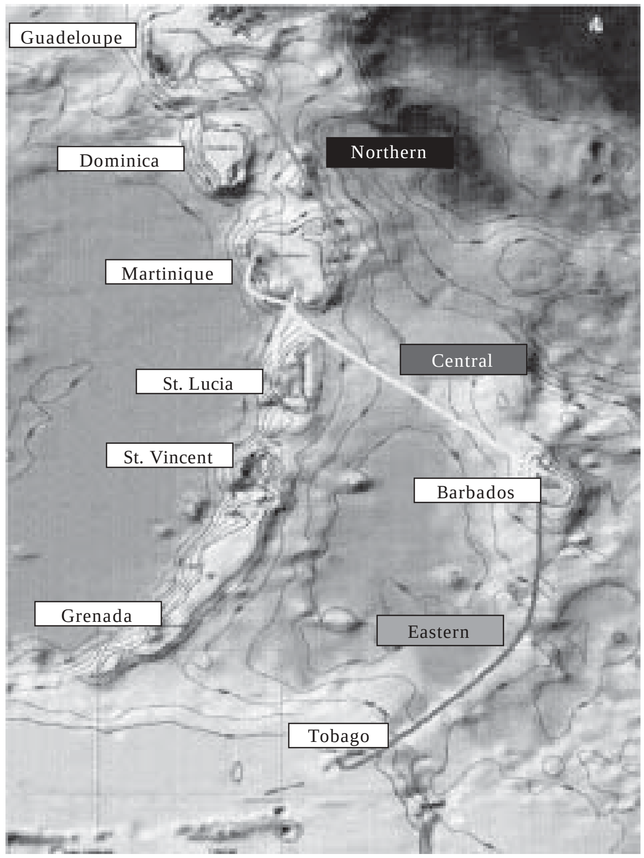
At the outset, the project was conceived to supply natural gas to the electric power sector in the five islands. The power companies in Barbados and St. Lucia are creditworthy entities listed on the Barbados and Eastern Caribbean Stock Exchanges, respectively, while Electricité de France (EdF) is the owner and operator of the power sector in the two French Departments. As such, the major gas offtakers are creditworthy companies. Table 2.18 summarizes the peak electricity demand and energy generation in 2005 for the five islands in question.

In Martinique, Barbados and St. Lucia, the power systems are supplied completely by imported petroleum fuels. However, in Dominica, run-of-river hydro accounts for about 35 percent of the generation, while in Guadeloupe, though the power supply system relies primarily on imported petroleum fuels, there is also some limited generation from hydro, geothermal, bagasse and wind resources.

Some of the principles that underlie the project are:

- Predictable, nonvolatile delivered gas prices primarily to the regulated power sectors, to "decommodify" fuel costs;
- Gas supply from Trinidad at market, not subsidized prices;
- Uniform fiscal and regulatory regime;

Figure 2.7: Routing of the Eastern Caribbean Gas Pipeline



Source: Eastern Caribbean Gas Pipeline Company Limited, 2005.

Table 2.18: Peak Electricity Demand and Gross Generation in 2005

Islands	*Peak Demand (MW)*	*Energy Generation (GWh)*
Barbados	147	940
Dominica	14	88
Guadeloupe	230	1,420
Martinique	228	1,395
St. Lucia	48	315

Source: Eastern Caribbean Gas Pipeline Company Limited (2005).

- ECGPC acts solely as a transporter of gas between the seller and buyers of the gas;
- Gas consumers purchase gas from the gas producer, with both contracting with ECGPC to transport the gas at a given tariff; and
- Internationally accepted commercial terms and conditions for pipeline systems to be used include: inter-governmental agreements between the governments, host government agreements between governments and ECGPC, and commercial and financial agreements between ECGPC and construction contractors, purchasers of gas, sellers of gas and financiers.

Since all petroleum-fueled power stations in all five islands are on the coast, the construction of onshore gas pipeline systems in Martinique and Guadeloupe would be undertaken primarily to deliver gas to the nonpower sector users – the commercial, industrial and household users close to any onshore pipeline routing. However, the economics and development of such onshore gas distribution systems would need to be established by the local authorities. A fairly extensive gas distribution system (about 40 miles) already exists in Barbados delivering the small volume of locally-produced natural gas.

The key determinate of project viability is the net incentive for the power companies to switch to natural gas. This means that the delivered gas price would need to be sufficiently below that of bunker C fuel oil (in the Barbados market), the lowest cost fuel that would need to be substituted for. At the time the feasibility study was undertaken, delivered bunker C prices were in the range of US$26-28 / bbl, while WTI was about US$36 / bbl in Oklahoma. Since 2004, WTI prices have virtually doubled and subsequently retreated to the US$55-60 / bbl range, with prices below US$45 / bbl considered unlikely on a sustained basis. This implies that the incentives for gas substitution are sufficient to accommodate the needs of all stakeholders. Table 2.19 shows the investment cost estimates, capacity and distances between the three segments of the ECGP.

As noted in the ESMAP report on "Energy Issues and Options in the OECS,"[25] once the pipeline infrastructure is in place, the possibility of recompressing the gas in Guadeloupe and shipping small parcels of CNG to islands such as Antigua and Barbuda, St. Kitts and Nevis, and British and US Virgin Islands could arise. The feasibility of this would depend on the progress made in the economics of CNG marine transport technology for very small cargoes**.**

The ESMAP report indicated that Dominica's geothermal potential was under investigation, and that various estimates ranged from 100-300 MW, in the absence of any drilling program to confirm the resource base. A team from EdF had visited the island to assess the situation and examine the prospects of exporting about 50 MW of electricity to both Martinique and Guadeloupe, via DC submarine cable over distances of about 40 miles. If it is proven that the geothermal option would satisfy all of EdF requirements, then the ECGP would terminate in Barbados.

Table 2.19: Investment Cost Estimates, Capacity and Distances of the ECGP

System	*Gas Capacity (mmcfd)*	*Investment Cost (US$ millions)*	*Miles*
Tobago to Barbados	50	170	180
Barbados to Martinique/St. Lucia	52	210	130
Martinique to Guadeloupe/Dominica	34	170	155

Source: Eastern Caribbean Gas Pipeline Company Limited (2004).

[25] *OECS Energy Issues and Options*, ESMAP Technical Report 317 / 07, February 2007.

The Midstream Refinery Sector

A major regional study on the refining sector was funded by ESMAP and the Canadian International Development Agency (CIDA) and issued in August 2002. The study was undertaken by Comcept Canada Inc., and supported by a Steering Committee comprising representatives from Asociación Regional de Empresas de Petróleo y Gas Natural en Latinoamérica y el Caribe (ARPEL), OLADE, the World Bank, PDVSA, Repsol-YPF, Pemex, Petrobras and Petrotrin. The study divided LCR into four subregions excluding the Caribbean refining centers in the two dependencies of Aruba and US Virgin Islands, and the two refineries in Puerto Rico. These four subregions are shown in Table 2.20.

Table 2.21 presents the increase in refinery capacity estimated in the study in the high petroleum product demand case scenario. The growth rate in this demand was taken as 4 percent annually between 1998-2015 while the low demand growth scenario reflected a growth rate of 1-2 percent annually. The high rate can be considered to be on the high side given that the study was undertaken during a period when oil prices were low, substitution with gas was still at an early stage and climate change issues had not yet gained widespread support.

Table 2.22 shows the investment estimates for refinery expansion in LCR for the period 1998-2015 in the 4 percent annual growth in product demand. Investment costs are broken down between the demand and environment-related investments, of which the former accounted for about 81 percent of the total investment of an estimated US$34.2 bn over this period.

Table 2.20: Subregional Groupings in LCR Refinery Study, 2002

Region1	Mexico, Guatemala, El Salvador, Belize, Honduras, Nicaragua, Costa Rica
Region 2	Venezuela, R.B. de, Colombia, Panama, Northern Brazil, Suriname, Grenada, Guyana, Haiti, Barbados, Dominican Republic, Netherlands Antilles, Trinidad and Tobago, Jamaica, Cuba
Region 3	Brazil South, Argentina, Uruguay, Paraguay, Chile and Bolivia East
Region 4	Ecuador, Peru and Western Bolivia

Source: The World Bank, ARPEL and OLADE 2002, Latin American and Caribbean Refinery Sector Development Report.

Table 2.21: Estimated Increase in LCR Refining Capacity Between 1998-2015 in High Oil Demand Case

Years	*000s Barrels/Day*			
	Region 1	*Region 2*	*Region 3*	*Region 4*
1998	1,400	2,000	2,000	250
2005	1,800	2,500	2,450	300
2010	2,200	3,050	3,000	350
2015	2,625	3,650	3,625	375

Source: The World Bank, ARPEL and OLADE 2002, Latin American and Caribbean Refinery Sector Development Report.
Note: Regions 1, 2 and 3 were estimated to have roughly similar rates of growth in capacity – 4 percent annually – with Region 4 showing a much lower expansion rate.

Table 2.23 presents a detailed breakdown of investments according to the type of processing / conversion facilities required to meet estimated demand and environmental standards. Two points are worth noting. First, the investments in conversion facilities are about double of those in crude oil distillation capacity in Regions 1, 2 and 3, due to the need to reduce production of residual fuel oil and increase the ratios of gasoline and distillates given the heavy crude oil being processed generally. Second, the estimated US$4 bn investment in hydrotreating in Region 1 is about double of that in Regions 2 and 3 due to the high sulfur content (2.17 percent) of Mexican crudes compared with about 0.64 percent in Region 3.

Since the growth rate of petroleum product demand during the period 2005-15 is likely to be lower than that assumed at the time of the study due to the impact of intensified substitution with gas and other energy sources, the investments over this period have been re-estimated based on a 3 percent rather than the 4 percent annual increase in demand in the study. All other factors remained as in the study, such as the ratio of conversion / processing facilities to crude oil distillation capacity. This resulted in a re-estimated refinery investment of US$18 bn (US$ 2002) for the 2005-15 period. This is a sector in which Public-private Partnerships (PPPs) could play a significant role in enhancing the efficiency of the sector as well as mobilizing the required resources.

Table 2.22: LCR – Refinery Investment High Oil Demand – Through to 2015 – Investment, US$ Million

Items	*Region 1*	*Region 2*	*Region 3*	*Region 4*	***Total***
Total Investment	13,290	9,350	11,000	550	**34,190**
Demand-related Investment	10,780	7,610	8,970	380	**27,740**
Environment Investment	2,510	1,740	2,030	170	**6,450**

Source: The World Bank, ARPEL and OLADE 2002, Latin American and Caribbean Refinery Sector Development Report.

Table 2.23: LCR – Refinery Investment Details High Oil Demand – Investment, US$ Million

	Region 1	*Region 2*	*Region 3*	*Region 4*	***Total***
Crude Distillation	1,876	1,633	2,310	0	**5,819**
Conversion	3,667	3,765	5,134	290	**12,856**
Upgrading	1,581	644	175	80	**2,480**
Hydrotreating and H2	4,001	2,048	1,447	150	**7,646**
Miscellaneous	2,146	1,260	1,908	30	**5,362**
Total Investment	**13,289**	**9,350**	**10,974**	**550**	**34,190**
Crude Sulfur (Weight%)	2.17	0.74	0.64	0.95	
Gasoline/Distillate Ratio	1.2	0.74	0.56	0.37	

Source: The World Bank, ARPEL and OLADE 2002, Latin American and Caribbean Refinery Sector Development Report.

The Oil and Gas Sectors Macroeconomic and Fiscal Linkages in Mexico and Argentina

To maximize the contribution of the oil and gas sector to Mexico's economic and social development, the government needs to address measures that would guarantee the sustainable contribution of the sector to the economy; minimize the net demands of the sector on public finances; reach international levels of efficiency; and mitigate environmental impacts associated with the expansion of the sector.

Currently, oil revenues contribute about one-third of the federal budget, with this rising to about 40 percent in 2005 and 2006.[26] This results in the budgets of both Pemex and the federal government being very vulnerable to oil price shocks. Compounding this, Pemex's financial obligations to the government make it very difficult for the company to implement a sustained investment program over the long term to ensure that hydrocarbon reserves are enhanced, and allow production levels to satisfy a rising national demand, and maintaining an appropriate level of exports.

Previous Mexican administrations have proposed reforms of the institutional and fiscal structures linking Pemex to Hacienda, and to promtote private sector participation. Some of these proposals were implemented, though others were not. In January 2006, a new tax structure for the oil and gas sectors was adopted to ensure the financial stability of Pemex. Prior to this reform, the fiscal regime for Pemex focussed on charging high royalties on gross production. Pemex, therefore, had to transfer at least 60.8 percent of its total sales to the Treasury, resulting in upstream activities transferring profits to pay the same rate of taxation in the downstream. This stripped the company of resources for E&P, repair and maintenance and the refining side, and resulted in a crushing debt. Indeed, Pemex's 2005 financial statement indicated that it had US$99.2 bn in total liabilities, and US$96.7 bn in total assets. During that year, Pemex registered before tax earnings of US$51 bn, a 13 percent increase over 2004 due to higher oil prices. However, the company's net result after taxes and duties was a loss of US$3.8 bn.

The new tax regime has brought a slight improvement to Pemex. During the first nine months of the new fiscal regime of 2006, Pemex paid the equivalent of 56 percent of its total sales in taxes and duties compared with a 62.5 percent fiscal burden in 2005. However, the new fiscal regime has to come closer to international practice if it is truly to have the desired impacts in preserving and increasing oil tax revenues; give clear incentives to invest efficiently in new projects; and maximize economic yield of existing fields similar to those elsewhere in the world. The government needs to recognize that charging royalty rates of 78-87 percent damages Pemex's finances, and does not provide the right incentives to maximize reserves. Above all, it is not the only mechanism to maximize fiscal revenues. For example, Canada,

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[26] *The World Bank-Mexican Policy Notes;* Chapter 9: Oil and Gas Sector; by Enrique Crousillat and Juan Carlos Quiroz, 2006.

Chile, Colombia and Norway register a government oil take of about 70 percent, while charging the industry with effective royalty rates of 8 percent, 7 percent, 27 percent and 0 percent, respectively.[27]

The urgency in completing the fiscal reform process, as outlined above, cannot be overemphasized given the recent statements by the Chief Executive Officer of Pemex that the company needed US$18 bn annually for the next 10 years compared to spending some US$10 bn annually in recent years. Raising this increased level of resources will be no mean feat. In 2005, the government's total investment (programmatic and off-balance sheet expenditures) was about US$33 bn, which was about 20 percent of the federal government's fiscal revenues for 2005. Of this, Pemex received about US$10 bn (about one-third) which was approximately similar to the amount invested on major social programs[28] for poverty alleviation, health, education and rural infrastructure. Indeed, in the absence of significant private sector participation in the massive investments required in oil and gas over the next decade, any increase in the allocation for oil and gas sector investment will entail a choice about the extent to which oil rents could be used to finance high-priority social programs and other spending priorities at the federal level or to finance increased oil and gas production and refining. A path needs to be found to allow private investment in the sector to alleviate the burden on public finances.

The hydrocarbon sector plays a major role in Mexico's economy and provides important contributions to the federal budget. There are very clear indications that the present institutional arrangements and E&P models are unsustainable. Reforms of institutional and fiscal structures that link Pemex to Hacienda, as well as measures to promote private sector participation in the industry, are necessary. This would enable the financial challenges facing the sector to be met, while mobilizing advanced technology, especially for the deep offshore. The challenge facing Mexico over the next five to 10 years is that failure to implement these measures and attract investment and technology to the sector could lead to reductions in oil and gas production which, in turn, would result in declining oil exports, increased petroleum and gas imports, major impacts in Mexico's fiscal position and an economic slowdown.

In the case of Argentina, arriving at estimates of the fiscal impacts of the oil and gas sectors is a challenge.[29] As a first approximation,[30] such a balance was undertaken in 2006. The exercise focused on the main items of expenditure and income specific to the sector,

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[27] International Exploration Economics, Risk and Contract Analysis by Johnston, 2003, page 62.

[28] *"SHCP – Informe Sobre la Situación Económica, las Finanzas Públicas y la Deuda Pública,"* Fourth Quarter 2005 and available at www.shcp.gob.mx

[29] This arises because the fiscal incomes in the gas and oil sectors are collected by different jurisdictions – federal, provincial and municipal. In addition, these different jurisdictions allocate the resources to finance investments and subsidies in the sectors. This multiplicity of resources and jurisdictions, and the accompanying challenges in accessing the information, makes the realization of the oil and gas sectors' consolidated national fiscal balance difficult.

[30] *"Argentina – 2006 Fiscal Balance for the Energy Sector – First Approximation,"* The World Bank Note, 2007.

implying that it did not consider the "tributary" income (for example, VAT taxes on sales, and so on, and so forth) from within the sector. Regarding expenditure within the sectors, only specific transfers realized at the federal level, excluding expenses and investments in provincial jurisdictions, were taken into account. The results were that the estimated total fiscal income from the oil and gas sectors in 2006 was about US$16.4 bn, of which royalties on oil and gas production (which accrue to the provincial authorities) amounted to 20.6 percent (US$3.36 bn) and 15.4 percent (US$2.53 bn), respectively, of the total income. Taxes on petroleum products accounted for 39 percent (US$6.41 bn) of income, while "withholdings" on the export of crude oil accounted for 16 percent of the income, with similar deductions on natural gas and petroleum product exports amounting to some 9 percent of the total income.

Main Challenges and Constraints

In spite of substantial progress made in the implementation of energy sector reforms, the countries in the region face new threats, challenges and opportunities to meet the overarching goal of ensuring a sufficient, efficient and sustainable energy supply over the next 10 years:

Generation Expansion

- The power sector reform, based on private participation and competitive wholesale markets or single buyer schemes with IPPs, was very effective in mobilizing private capital to expand generation capacity based on technologies that could take advantage of low price natural gas or residual oil, and could reduce market and country risks for the new investors – CCGT and MSDs, characterized by low capital costs, high efficiency, short construction periods and low generation costs;

- Although the increase of the participation of thermal generation during the past 15 years helped to achieve, in some countries, a more balanced hydro / thermal generation mix – less vulnerable to droughts – it created its own problems. Most countries dependent on imported fuels that relied on diesel engines (Central America and the Caribbean) or CCGT (Chile) became vulnerable to high and volatile oil prices or to gas supplied from a single source. This situation had serious consequences: the impact of high and volatile fuel prices on generation costs could not be passed through to tariffs due to its political impact, thus creating serious financial problems for governments, privatized Discoms and IPPs. Also, the disruption in gas supply threatened the security of energy supply;

- The countries dependent on imported fuels have adopted a policy of diversification of energy sources to improve energy security, reduce generation costs and mitigate the volatility of liquid fuel prices. This includes promotion of exploration activities for oil and gas; development of indigenous renewable resources (hydro, wind, geothermal, biomass, biofuels); import other fossil fuels (LNG, pipeline natural gas, coal); and expansion of the capacity of electricity interconnections with neighboring countries;

- Countries with natural gas reserves or with access to imports of natural gas by pipeline (Mexico, Bolivia, Argentina, Peru, Colombia and Brazil) continue to rely on thermal expansion based on gas-fired GT and CCGT to meet expected demand for 2005-15. Although this appears to be a least-cost generation expansion strategy, it may not minimize risks. Except for Peru and Bolivia, which have ample reserves, the other countries face the risk of constraints in gas supply or high gas prices;

- Countries which are considering LNG as an option to mitigate the volatility of liquid fuel prices may find out that this is not a very effective strategy because international LNG prices are tracking those of crude oil. Coal is clearly the only conventional fuel whose price not only has remained decoupled from that of oil but, above all, its price ranges from 50-60 percent less than that of gas. This means that even SubCritical coal-fired steam plants could displace CCGTs for baseload operation, unless prices of gas are quite low – below about US$3.50-4.00 / MMBTU; and

- The prospects for high oil prices in the long term and the vulnerability to external shocks have renewed the interest of all countries in the development of hydroelectric resources, RE, EE and energy conservation programs. With current and projected oil prices, most of these technologies and programs are commercially viable provided that the right incentives and policies are put in place.

On Investment Needs

- The annual rate of growth of electricity demand in many countries in the region dropped in the late 90s and early 2000s as a result of the economic and energy crisis. However, demand growth has recovered, and most countries are projecting demand growth rates higher than those of the early 90s;

- It is estimated that, in 2009-15, the region would have to invest about US$20 bn per year in generation, and T&D projects that are not under construction or have not been contracted. This amounts to about five times the private investment that was mobilized for greenfield projects in the past eight years; and

- About 55 percent of the projected investment needs are in about 60,000 MW of new generation capacity. To diversify the energy sources, it is necessary to develop hydroelectric projects, renewable power and coal-fired plants, which entails higher investment costs and longer construction periods while yielding lower levelized generation costs.

On Power Sector Reform

- The combination of private participation, competitive wholesale markets and economic regulation was effective in improving the efficiency and quality of service of generation and distribution companies in many countries;

- However, private participation is not sufficient to improve the performance of the sector. Some experienced international operators failed to improve the performance of Discoms in difficult environments with political frameworks that did not support cost-recovery tariffs nor penalized theft and fraud;

- The poor were not the main beneficiaries of efficiency improvements;

- There was a drop in private investment in the region since the late 90s, and a flight of private investors caused, in part, by the difficulties in earning an adequate risk-adjusted return on investment in countries with high country and market risks;

- The threat of large tariff increases and energy shortages has prompted government intervention to change market rules and control prices, which undermined the authority of regulatory institutions and the credibility of government commitments. Diversification of energy sources and incentives for efficient generation expansion can help to reduce the risks of interventions;

- There is political opposition and dissatisfaction with privatization and liberalization policies. However, in spite of economic and energy crises, market failures and incomplete reform processes, returning to a public sector model is not an option;

- Technical competence and independence of regulatory institutions are essential to build legitimacy and restrain political opportunism. In many countries, the regulatory institutions remain weak and lack credibility;

- Most countries in the region are establishing obligations to supply a substantial portion of the regulated market with long-term supply contracts awarded by competitive bidding procedures as an instrument to hedge price risks, mitigate market power and facilitate financing of new investments;

- The public sector still controls a substantial portion of generation and distribution and most of the transmission in many countries. Some SOEs in Ecuador, Colombia, Honduras, Guyana and the Dominican Republic are inefficient and have limited internal generation of funds resulting from poor governance arrangements; and

- The financial viability of many utilities is at risk. Electricity revenues are not sufficient to cover full supply costs in many countries due to the impact of high fuel prices on generation costs (Central America and the Caribbean), economic crisis (Argentina), difficulties in controlling losses and improving collections (the Dominican Republic, Honduras, Nicaragua, Colombia, Ecuador) and reliance on generalized tariff subsidies.

Challenges

Although competition and private participation are still important instruments to improve performance and reduce the fiscal burden of the energy sector, it is clear that the energy strategy of the 90s has to be adapted to the new realities and challenges of the region. Competitive markets in LCR should ensure sufficient power capacity to meet demand and stable electricity tariffs – two ingredients that are essential for the political survival of any government. Private investors are reluctant to take the country and project risks in many countries in the region, and public support is needed. There is political opposition to further divestiture of public assets to foreign investors.

A new strategy is needed to enhance energy security, improve access to energy services for the poor, mobilize the financial resources required to meet power sector investment needs and improve governance and institutional frameworks.

ENHANCING ENERGY SECURITY

Energy security has become a major concern in developing countries due to the threats to energy supply posed by political instability and natural disasters, the increased energy import dependency of many countries, the growing energy demand and the lack of an adequate supply, the prospects for high and volatile oil prices and the need to tackle climate change. Energy security has become a new priority that encompasses all energy policies and actions. The Group of Eight (G-8) group has adopted the following principles to enhance security:[31] open, transparent, efficient and competitive markets; transparent, stable and effective legal and regulatory frameworks; diversification of energy supply and demand and energy sources; promotion of energy savings and EE; deployment and transfer of clean energy technologies; promotion of good governance of the energy sector; and providing energy services to the poor.

In the case of LCR, we propose to limit the concept of energy security to the diversification of energy sources and the promotion of energy savings and EE. Diversification includes: promotion of exploration activities for oil and gas, development of indigenous renewable resources (hydro, wind, geothermal, biomass and biofuels), import of other fossil fuels (LNG, pipeline natural gas and coal), expansion of energy interconnections and strengthening of the legal and institutional frameworks for regional energy trade. The countries in the region dependent on imported fuels and vulnerable to external shocks have adopted a policy of energy diversification and EE to improve energy security, reduce generation costs and mitigate the impact of the volatility of fuel prices. Other countries in the region, less dependent on imported fuels, have adopted the same policy to improve the reliability of electricity supply and accelerate the development of clean energy.

The implementation of an energy security policy in the region is a major challenge, because:

- An energy diversification policy should be sustainable and economically efficient. It is not always easy to reconcile these objectives;

[31] G-8 St. Petersburg plan of action on global energy security, 2006.

- Diversification usually comes at a higher cost (for example, development of renewable power and new backup sources of supply), and to ensure sustainability, the incremental cost should be bought down by international grants (for example, GEF, carbon trade and fiscal incentives or passed through as higher energy prices;

- It is necessary to put in place the right incentives to ensure that investors select projects that meet the diversification objectives at least cost and do not act in a manner pursuing purely short-term profit objectives;

- An energy security policy, based on self-sufficiency of energy sources, is not feasible in most cases and, in any case, is neither efficient nor sustainable. In spite of the recent difficulties in enforcing cross-border firm energy supply contracts in the Southern Cone, energy trade in the region is still a key element to diversify energy sources;

- Diversification of energy sources often entails the development of projects with higher capital cost and longer construction periods, a combination of factors that increases market and project risks which private investors are reluctant to take. Support of the public sector is required; and

- Diversification may not be effective in mitigating price risks if the prices of the fuels used for power supply are correlated. As discussed here, this may be the case for pipeline natural gas, LNG and liquid fuels. In this context, power sector diversification strategies need to examine closely all the thermal options of low-sulfur coal and Clean Coal Technologies (CCTs).

IMPROVING ACCESS TO ENERGY SERVICES FOR THE POOR

In 2005, about 50 mn people in Latin America, mostly in rural and poor areas, did not have electricity service. Electricity coverage between countries in the region was uneven in 2005. Based on information available for LCR, excluding the Caribbean (which represents only 4 percent of the population of the region), there were eight countries which represent 78 percent of the population of the region, with electricity service coverage above 90 percent, while three countries (Nicaragua, Honduras and Bolivia) with 4 percent of the population had service coverage below 70 percent (Table 2.24). Coverage in the rural areas in the group of countries with low national coverage is usually about 30 percent (28 percent in Bolivia in 2003 and 35 percent in Honduras in 2004).

The investment per household in distribution grids to connect unserved areas increases as coverage increases (longer distance to the grid, higher dispersion of households, lower load densities). For example, in Chile, the average government subsidy per household increased from about US$1,300 to increase coverage in rural areas from 62 to 76 percent in 1995-99 to about US$1,700 to go from 76 to 90 percent in 2000-05.

The investment needs to continue increasing service coverage in the region during the next 10 years are substantial. According to the annual rate of growth of population projected

Table 2.24: LCR – Electricity Coverage 2005

	Population 2005	Electricity Coverage	Population w/o Electricity
	million	%	million
Argentina	38.7	95%	2.1
Bolivia	9.2	69%	2.8
Brazil	186.4	92%	15.8
Chile	16.3	98%	0.3
Colombia	41.5	94%	2.7
Costa Rica	4.3	99%	0.1
Ecuador	13.2	89%	1.5
El Salvador	6.9	82%	1.2
Guatemala	12.6	83%	2.1
Honduras	7.2	69%	2.2
Mexico	103.2	93%	6.8
Nicaragua	5.5	54%	2.5
Panama	3.2	86%	0.5
Paraguay	6.2	87%	0.8
Peru	28.0	77%	6.3
Uruguay	3.5	95%	0.2
Venezuela, R.B. de	26.6	92%	2.2
Total	**512.4**	**90%**	**50.1**

Sources: Prepared by authors based on CIER and ECLAC data in Web pages and official country statistics in the case of Colombia, Mexico and Chile.

by ECLAC for 2005-15 (about 1.3 percent), there would be a population increase of about 70 mn people in this period. If electricity coverage is increased to 95 percent by 2015, about 24 mn households would have to be connected. However, about 80 percent of the population in the region lives in urban areas, and it is estimated that only 40 percent of the new connections would be in rural areas. Assuming an average investment per connection of US$1,500, the total investment in distribution grids for rural electrification would be about US$14 bn during the next 10 years.

The investment needs of rural electrification in the group of countries with low service coverage (Nicaragua, Bolivia and Honduras) (Table 2.25) are also substantial relative to the size of the electricity market. To increase service coverage to 80 percent by 2015 (or 55 to 65 percent coverage in rural areas), each of these countries would have to

Table 2.25: Rural Electrification Low Coverage Countries

	Population 2005	Electricity Coverage	Population 2015	Target Coverage	Rural Coverage	New Connections (000)		Investment
	Million	%	Million	%	%	**Total**	Rural	US$mn
Bolivia	9.2	69%	11.1	80%	56%	**594**	315	315
Honduras	7.2	69%	8.9	80%	65%	**342**	205	205
Nicaragua	5.5	54%	6.6	80%	65%	**399**	302	302

Source: Authors' calculations.

invest about US$20-30 mn per year during the next 10 years just in distribution expansion in rural areas, in addition to the required expansion of subtransmission, transmission and generation needed to meet the increased demand, and the additional subsidies implicit in the lifeline tariffs for low-income consumers.

MOBILIZING FINANCIAL RESOURCES REQUIRED TO MEET POWER SECTOR INVESTMENT NEEDS

Financing investment needs to meet expected electricity demand in the region during the next 10 years is a major challenge. An annual investment of about US$20 bn would be required, which represents about five times the average investment mobilized in greenfield projects with private participation during the last decade. Furthermore, the future conditions that the power sector in many countries in the region will face make it difficult to mobilize these resources:

- Private investors are reluctant to take the high country and market risks of many countries in the region (for example, Argentina);
- In some countries, private- and State-owned distribution utilities are in financial distress because electricity tariffs lag behind supply cost. External shocks (macroeconomic crisis and impact of high oil prices) and lack of political will to align tariffs with costs are contributing factors (for example, Argentina, Nicaragua, the Dominican Republic, Honduras, Ecuador and Guyana);
- SOEs still play a major role in many countries but do not work as commercial firms, are inefficient (high electricity losses, inadequate collections, high operating costs), and do not produce sufficient internal generation of cash to finance a portion of new investment. Usually, the fiscal space available is limited to finance expansion with external debt (for example, Honduras, the Dominican Republic);
- As explained above, energy diversification usually increases the project and market risks for private investment in generation (hydroelectric plants, clean coal power plants, geothermal and other small renewable power); and

- Additional annual investments of about US$1.4 bn in rural energy projects would have to be financed by international grants and investment subsidies.

Financing generation projects. About US$15 bn or 21 percent of the generation investment needed in 2006-15, that is not under construction or already contracted, corresponds to projects that could be developed by the private sector (foreign and domestic) under IPP schemes (CCGT, GT and small renewable power) under long-term contracts. Financing of wind power, biomass and small hydro projects would require adequate fiscal price and carbon finance incentives.

About US$48 bn, or 67 percent of the generation investment, corresponds to projects that are not well suited for traditional nonrecourse project finance. This generation capacity is in medium or large projects with high fixed costs and long construction and payback periods (medium and large hydro, coal plants and geothermal plants). The experience with private development of hydropower in the region shows that:

- The combination of long development and construction periods, high capital costs and construction costs subject to contingencies increase the project and market risks for the developer and the financial costs of the project;

- About 95 percent of the generation costs are fixed costs that should be covered with a volatile generation dependent on hydrological conditions;

- There is usually a mismatch between the duration of long-term supply contract, the amortization of the debt and the payback period that increase the project risks;

- The process of obtaining the licenses and permits (water rights, environmental license) is long, unpredictable and risky due to opposition by some Nongovernmental Organizations (NGOs), bureaucratic approvals and public consultation;

- The implementation of resettlement plans of displaced population is risky and politically sensitive; and

- The arrangements whereby all risks are ring-fenced is expensive because each shareholder should make a generous provision for risks that are expensive to manage if they are not pooled.

Usually, a PPP approach must be used for the development of medium and large hydroelectric projects, in which the private partner brings the best management practice and technical expertise and secures funding, and the public partner secures timely granting of licenses and permits, facilitates implementation of the environmental mitigation plan, provides payment guarantees and facilitates other financial support mechanisms that reduce the financial costs. Brazil intends to implement its substantial hydropower development plan using mainly centralized public auctions to award concessions for the development of hydroelectric projects with environmental licenses already approved and with a long-term PPA of up to 40 years for the firm energy delivered by the project, and financing support by BNDES. SOEs participate in the auctions and secure project funding with equity (internal generation of cash) and debt. The private sector in Panama has developed medium-sized hydroelectric projects (Estí, 120 MW hydro plant) based on long-term PPAs of maximum 10 years duration, due to strong support of the government, stable market rules, moderate country risks and negligible exchange risks.

The diversification of energy sources can improve the sustainability of long-term PPAs needed to facilitate financing of high capital cost projects. The experience with IPPs in the region shows that although long-term PPAs do protect private investment by providing a stable revenue stream, it is not realistic to think that a full pass-through to consumers of contract costs is sustainable when planned conditions change due to external shocks. The development of hydropower, coal thermal plants and geothermal plants helps to reduce the vulnerability of generation costs to external shocks and, therefore, helps to improve the sustainability of long-term PPAs. In the case of hydroelectric projects, this is true if the hydrology risk of the new project can be pooled with the existing generation plants. In other words, when the new project helps to diversify the existing energy sources. However, there are two situations when long-term PPAs will not be sustainable, in spite of any security package: (i) electricity tariffs that do not cover efficient average generation costs; and (ii) bad projects that do not correspond to least-cost solutions.

Well-run SOEs operating with cost-recovery tariffs usually have sufficient internal generation of cash to finance the development of new generation projects and mobilize complementary funding from multilateral institutions, export promotion agencies and capital markets. That is the case of Empresas Publicas de Medellin (EPM) in Colombia, Instituto Costarricense de Electricidad (ICE) in Costa Rica and Companhia Paranaense de Energia (COPEL) in Brazil. Usually these domestic companies are in a better position to secure licenses and permits and implement the environmental management plans.

There are also well-run private companies already operating in the region that are a source of equity financing if the wholesale market rules ensure a reasonable risk adjusted rate of return on investment. That is the case of AES in Panama.

Financing T&D projects. As was mentioned before, the public sector controls a substantial portion of transmission companies in the region and, in most countries, the transmission expansion plans are centralized. Usually, the transmission charges provide a reliable revenue stream to cover investment and operating costs. Financing of investment needs in transmission can be done by the incumbent transmission companies with equity or debt or through concession contracts with new operators under traditional project finance schemes.

Considering the lack of appetite of foreign private investors for divestiture of Discoms, and the dissatisfaction with privatization policies in many countries, it would be expected that financing of distribution expansion will be done by the incumbent private companies, SOEs already operating in the region and the participation of domestic private capital.

Mobilizing domestic private capital. Domestic private capital markets can play a central role in financing the investment of electric power utilities that generate little or no hard currency, and are exposed to foreign exchange risk. One source of financing are the Private Pension Funds, pioneered by Chile in 1981, and established in many countries in the region in the 90s,[32] which, by mid-2006, amounted to about US$192 bn (Arthur, 2006), and represent a source of long-term capital. Pension funds in Chile have been major investors in the power sector in this country since its privatization in the late 80s. For example, in the early 90s, they owned about 30 percent of Empresa Nacional de Electricidad S.A.(ENDESA), the largest power utility. Investments in bonds and shares in the power sector increased from US$1.3 bn in 2002 to US$2.5 bn in mid-2004, and US$3.2 bn in mid-2006. Pension funds in Bolivia received 50 percent of the shares of the power utilities that were privatized in the 90s. Pension funds in Colombia have a preferential right to participate in the privatization of SOEs and, in 2006, submitted an unsuccessful bid of about US$820 mn for the control of a national gas transport company.

Although domestic bond markets have become the largest single source of financing in emerging markets, just a few countries in LCR have been able to develop domestic capital markets and open them to infrastructure financing.[33] Establishment of private pension funds, well-regulated capital markets, sound macroeconomic policies and a financially sound power sector are key factors for success. Chile has been able to develop a relatively deep domestic capital market. Well managed and financially strong power utilities (both private and State-owned) in Colombia have issued about US$800 mn in corporate bonds in the domestic market during the past three years. Interconexión Eléctrica S.A.'s (ISA´s) public offering of shares in the domestic market reached a 28 percent ownership in 2005, with a market capitalization of more than US$500 mn.

IMPROVING GOVERNANCE

The assessment of power sector reforms concluded that governance matters for development and private participation. Investors in the region give a high priority to the stability of enforceability of laws and regulations, and to regulatory independence, as conditions to attract private investment. Good corporate governance of SOEs is essential to improve performance. Many regulatory institutions in the region lack the technical competence and independence required to build legitimacy, improve the credibility and stability of the new market rules and restrain political opportunism. Countries with financially weak and inefficient SOEs, that are main providers of electricity service, will have to improve their corporate governance.

[32] *Argentina, Bolivia, Colombia, Mexico, Peru and Uruguay, Costa Rica, the Dominican Republic and Panama in the early 2000s.*
[33] *Chile, Brazil, Mexico, Argentina and Colombia (Deloitte, 2004).*

Regulatory Governance

Although the design of the governance of regulatory agencies in LCR received good marks in a recent survey (Andres, 2007), experience shows that good governance design alone is not enough to create commitment to a transparent and unbiased application of rules and regulations: governments have interfered in the regulatory process; discretion in the application of general rules have created uncertainty and instability; and the boundaries between policy making and regulation are not well-defined.

An option to create commitment is to combine regulatory independence with a clearly specified regulatory contract (for example, concession contract for distribution) that must be negotiated by political authorities (Bakovic et al., 2003). Regulation by contract limits the discretion of the regulator in areas that are known to deter investment, but uses its autonomy to avoid uncertainties for investors. The regulator should enforce the contracts and adjust to changes in circumstances, in a transparent and independent manner, subject to appeals processes.

Concession contracts define clearly the rights and obligations of the concessionaire, including the formulas and procedures to determine electricity tariffs, reliability and quality of service standards, and the obligations to expand electricity coverage. The pioneer reformers (Chile, Argentina, Bolivia and Peru) established the principles, rules and procedures that govern the regulatory contract in the primary or secondary electricity legislation. The experience shows that independent regulation and regulation by contract are complements rather than substitutes in the case of the power sector. It is not possible to write enforceable long-term contracts that can cover all possible contingencies, and good regulatory governance allows for simpler contracts that are easier to monitor, enforce and renegotiate.

Regulation by contract reduces the risks perceived by private investment under a new regulatory regime, but does not solve the problem of weak regulatory institutions (the Dominican Republic), lack of political commitment (Argentina, the Dominican Republic) or lack of cost-covering tariffs. Technical competence of the regulator, political commitment to transparent and fair application of regulations and good regulatory governance (independent, nondiscriminatory and transparent application of the rules) are essential to build legitimacy and improve the stability and enforceability of rules and regulations.

Therefore, it is necessary to strengthen the technical competence and governance of regulatory agencies and develop regulatory schemes, which combine the predictability of contracts with the flexibility of independent agencies responsible for enforcing and adjusting these contracts, adapted to the special conditions of countries that do not have the Anglo-American tradition of the application of general principles by independent regulatory agencies.

Second-generation reforms of wholesale markets can reduce the risk of government interference in the regulatory process. Government interventions in the region have been motivated mainly by the difficulties in passing through volatile generation prices and the impact on the cost of service of currency devaluations to tariffs, and by the threat of energy shortages. The obligation to enter into long-term supply contracts, combined with a diversification policy, may reduce the volatility of generation prices, facilitate financing of new investment required to ensure sufficient generation capacity to meet demand and improve the enforceability of contracts. The experience in the region indicates that PPAs may not be sustainable if generation prices are vulnerable to external shocks.

The implementation of sustainable long-term energy supply contracts to ensure capacity adequacy for the regulated market poses new challenges in most countries in LCR which have established competitive wholesale markets. First, if energy prices under the contract are passed-through to the consumers to reduce the price risk to the Discoms that are contracting on behalf of the consumers, the Discoms will not have incentives to procure their energy needs efficiently. Generally, the regulator has to establish detailed rules for preparing the tender documents and for the bidding procedures to maximize competition. Second, contracts with a duration that covers the economic life of the generation plants facilitate financing but increase the risk that the plant may not be competitive in the future. A compromise has to be reached. Third, the procurement process should be structured in such a way that it produces a portfolio of energy supply contracts that mitigate price risks. This requires a combination of contracts with different durations and different cost structures, and eventually the use of call options. The development of adequate long-term contracts is still a challenge in all countries worldwide, and a subject of academic controversy (Millán, 2006).

Corporate Governance of SOEs

Corporate governance of most SOEs in developing countries is weak. There are two fundamental problems: (i) politicians and government officials do not act as ordinary, profit-motivated shareholders and, many times, pressure the company to pursue noncommercial goals; (ii) the government faces a conflict of interest as policy maker and provider of electricity service that undermines the quality of policy and regulation, when the rules are modified in a somewhat arbitrary manner to protect SOEs or to achieve noncommercial goals.

This explains the fact that SOEs are usually subject both to micromanagement and politically motivated interference by the government; accountability for the performance of SOEs is diffuse, with the intervention of the board of directors, ministries, president’s office and politicians; SOEs sometimes hold a monopoly position and are not subject to the discipline of a market; SOEs do not apply high standards of transparency and disclosure of financial and operational results; the administration of the SOE lacks operational autonomy to define its budget, making investment and borrowing decisions, procuring goods and services, and so on, and so forth; and the board of directors lacks the authority and independence to guide and supervise the management. Furthermore, SOEs are immune to two threats that discipline the management of private corporations and provide incentives for good performance: takeover and bankruptcy.

To improve the performance of government-owned electricity utilities, the rules and practices must be changed to make it harder for politicians and other interested parties to use the utilities for noncommercial purposes, and to introduce new sources of pressure to perform well. Privatization, competition and good regulation are effective instruments to improve corporate governance. When privatization is no longer an option, the idea is to apply the principles of good corporate governance to SOEs, which are well-defined (Organisation for Economic Co-operation and Development [OECD], 2005: Irwin, 2004):

- Ensure that SOEs compete with private companies in a level playing field. This implies, among other things, the separation of the roles of the State as policy maker, regulator and service provider, nondiscriminatory application of laws and regulations, no preferences in access to financing (government guarantees, special financial conditions by State-owned banks and institutions), that SOEs pay taxes;

- Ensure commercial operation of SOEs. This implies, among other things, that the objectives of the State's ownership are well-defined, that the government should give full operational autonomy to the administration of the SOE (define its own budget, making investment and borrowing decisions, managing personnel, and procuring goods and services), that the State should respect the independence of the board of directors, that the ownership rights are clearly assigned within the government;

- To apply high standards of transparency and disclosure, including independent external audits, disclosure of financial and operational results;

- To establish an independent board of directors, with sufficient authority to provide strategic guidance and supervise the management, and accountable for their actions and omissions; and

- To protect the rights of minority shareholders and ensure an equitable treatment. This implies that a minority of the company's shares will be listed in the stock exchange, and commercial performance will be monitored by the capital markets.

However, the experience in some countries of LCR shows that the corporatization of SOEs does not ensure better performance. In Colombia, Law 142 of 1994, which established most of the legal framework for the market-oriented reform, provided that State-owned public utilities, whether national, regional or municipal companies, could adopt a quasi-incorporated structure or remain under the direct control of the public administration. Many State-owned utilities were corporatized at the beginning of the reform process. However, after 10 years of operation under the new structure, the bad habits of the old SOEs still persist: the regional authorities maintain political control of the board of directors, there have been frequent changes in the administration and the performance is poor.

Politicians, labor unions and public opinion many times oppose the idea of corporatization of SOEs because this is considered to be the first step to privatization. In Colombia, many municipalities did not choose the corporatization option and opted to maintain direct control of municipal utilities. Only in the late 90s, when some municipal companies, in poor financial conditions, were under threat of intervention by the regulatory institutions, the municipal government decided to corporatize and privatize the SOEs.[34] However, in the early 2000s, when there was intervention in the large municipal utility of Cali, it was no longer feasible from the political point of view to corporatize and privatize this company.

There are also success stories of corporatization of SOEs with the participation of small local shareholders. ISA in Colombia, a SOE with a tradition of good management, was incorporated and placed 24.2 percent of equity among 90,000 small shareholders, in two public offerings of common shares. The government that controls this company adopted and has respected the principles of good governance, including the protection of the rights of minority shareholders. ISA has been able to expand its operations in Latin America, taking over transmission companies and projects in Ecuador, Peru, Bolivia and Brazil.

There are also examples in the region of SOEs that have a good performance and have not been corporatized. The cases of ICE in Costa Rica and EPM in Colombia are usually cited. These companies have a long tradition of good management and were able to attain a strong financial position taking advantage of vertical integration, a monopoly position and access to hydropower rents. They were also able to build a strong public support that has protected these companies from political intervention but, at the same time, has blocked initiatives to restructure or privatize these companies. EPM has become a cash cow for the municipal government and has expanded its operations in other regions in Colombia, taking over small and medium public utilities.

Some lessons can be learnt and conclusions can be reached from the experience in LCR in improving the corporate governance of SOEs in the energy sector:

- Restructuring and corporatization of SOEs maintaining a 100 percent public ownership is not sufficient to improve performance. Corporatization by itself does not prevent that regional and municipal politics maintain the control of the board of directors and intervene in the management of the company;

- Corporatization, participation of local small shareholders, and adoption of good governance principles may be an effective combination to improve performance of SOEs, as is illustrated by the case of ISA in Colombia. But a warning should be made: an essential requirement is that the SOE is restructured and commercialized first (cost-covering tariffs, restructuring of debt and other liabilities, renegotiation of labor contracts) so it can become financially viable and distribute dividends; and

[34] In Colombia, the Superintendence of Public Services (SSPD), responsible for the supervision of public utilities can intervene, restructure or liquidate utilities (private or State-owned) in financial distress. In 1996, the municipal power company of Bogota, which was in financial distress, was under the threat of intervention by the SSPD and the municipal government decided to implement a successful program to restructure, corporatize and privatize this company (the origin of CODENSA and EMGESA, two efficient private utilities).

- A competitive environment and accountability are essential factors for improving the performance of SOEs. Usually, the management of SOEs asks for full operational autonomy on budget, procurement and investment but expects also to benefit from a monopoly position. In the case of Colombia, for example, it has helped that ISA and EPM are subject somehow to the market discipline and are accountable to shareholders (ISA) or the local community (EPM).

3. Demand for Development Agency Support

Summary of Past Activities of Development Agencies

Inter-American Development Bank

IADB has been a leading investor in the energy sector in LCR among multilateral lending agencies, with about US$7.5 bn in loans approved in 1991-2006.

IADB's strategy and policy for energy lending evolved in the 90s as the reform of the energy sector progressed in the region. In 1995, IADB adopted a strategy for infrastructure that recognized private sector financing and guarantees as central concerns. The Public Utilities Policy, issued in 1996, adopted basic principles of market-oriented reforms based on separation of roles, private participation and competition. The Energy Strategy,[35] approved in 2000 by its board of directors, defined as IADB's main objectives: (i) supporting the consolidation of reforms; (ii) strengthening new energy markets emerging as a result of the reforms, and meeting their credit needs; (iii) offering assistance to tackle problems of energy supply and demand; and (iv) encouraging the use of new energy markets on an experimental basis.

IADB uses four windows to finance energy projects. The Public Sector Group finances energy projects that have the participation of the public sector and count with government guarantees. The Private Sector Department, established in 1994, provides long-term direct financing and guarantees for private sector participation in large infrastructure and public service projects without government guarantees. The Inter-American Investment Corporation finances small- and medium-scale private sector infrastructure projects and undertakes direct equity participation. Finally, the Multilateral Investment Fund encourages private participation in infrastructure through grants and operations to support the legal and regulatory environment, privatization of utilities, sector restructuring and institutional strengthening.

[35] IADB, Energy Sector Strategy, available at http://www.iadb.org/sds/doc/ENV%2D135E.pdf.

The IADB group has a strong lending program for basic energy infrastructure. In 1991-2006, it approved about US$5.3 bn in loans, grants and guarantees for power generation, T&D and oil and gas projects, of which 52 percent has been undertaken during the past six years (Table 3.1). Recently, IADB approved large loans for power generation (US$750 mn for the Tocoma Hydroelectric Plant in Venezuela and US$200 mn for the Porce III hydro plant in Colombia) and transmission (US$750 mn for the Norte Grande Transmission Program in Argentina). IADB also provided about US$240 mn loan to finance the Central American electricity interconnection as part of the *Plan Puebla-Panama*, an integration initiative for Mesoamerica (Table 3.2).

The IADB group has also provided strong support to energy sector reform, rural energy, renewables and EE. In 1991-2006, total financing in policy loans, investment loans, grants and technical assistance in those sectors amounted to US$2.1 bn (Table 3.1). IADB launched, in November 2006, a new initiative that will focus on EE, biofuels, carbon finance and climate change. This initiative will scale up IADB investments in RE and EE, foster sustainable energy investment and improve access to the carbon finance market.

The World Bank Group

The World Bank Group policies and strategies for the energy sector supported energy sector reform in the early 90s and evolved as new issues arose. By the early 90s, when lending to public utilities had become untenable, the World Bank Group adopted a policy to promote private sector development in the electric power sector. This was formalized in the 1993 Electric Power Lending Policy that concentrated lending in countries committed to satisfactory institutional and structural reform policies. This policy was endorsed by the International Finance Corporation (of the World Bank Group) (IFC) and supported by the

Table 3.1: IADB Group Energy Lending 1991-2006

	1991-95	*1996-2000*	*2001-06*	***Total***
Hydroelectric Generation	500	76	1,025	**1,601**
Thermoelectric Generation	121	154	112	**387**
Power Transmission	100	379	972	**1,451**
Power Distribution	54	90	292	**436**
Oil Industry and Pipelines	260	383	77	**720**
Combined G,T,D	35	430	274	**738**
Other (policy, RE, renewable, efficiency, etc.)	1,273	716	188	**2,177**
Total	**2,343**	**2,228**	**2,940**	**7,510**

Source: IADB.

Table 3.2: IADB Lending 1997-2006 – List of Large Energy Projects

Countries	*Name*	*Year*	*IDB Loan US$ mn*
Argentina	Gas del Sur (TGS) Gas Transportation	1998	326
Argentina	Norte Grande Electricity Transmission Program	2006	580
Brazil	Cana Brava Hydroelectric Power Project	2000	165
Brazil	North-South Electric Interconnection	1997	307
Brazil	Termobahia Cogeneration Plant	2001	173
Central America	Central America Electric Interconnection	2001	240
Colombia	Porce III Hydroelectric Power Plant	2005	200
Mexico	Thermoelectrica del Golfo, S.A. de C.V.	1999	177
Mexico	Yucatan Gas Pipeline	1997	210
Venezuela, R.B. de	Tocoma Hydroelectric Power Plant	2005	750
Regional	Gas Pipeline Integration Bolivia-Brazil	1997	240

Source: Prepared by authors based on IADB´s data in Web page.

Multilateral Investment Guarantee Agency (MIGA). The World Bank Group policies to promote private sector development in the power sector were complemented by activities in three strategic areas: EE; rural and RE; and environmental sustainability. The 1993 World Bank Group policies emphasized energy pricing to improve overall EE and promote environmental protection, private participation and competitive markets. In 2000 and 2001, the World Bank Group energy strategy focused on climate change, energy access, poverty alleviation, the adoption of cleaner energy technologies and supporting complex market reforms.

LCR has had a marginal share of the total energy lending program of the World Bank during the past 10 years. In the period from fiscal 1997 to fiscal 2005, LCR received only 8 percent of the total energy lending, compared to Europe and Central Asia (28 percent); East Asia and the Pacific (27 percent); and South Asia (19 percent) (Table 3.3). This can be explained by the fact that, in the 90s, LCR had progressed in implementing market-oriented reforms and had the largest share of private participation in the energy sector. While in other regions, the World Bank continued to finance large infrastructure investment projects, in LCR it moved to policy loans, renewables and EE.

The evolution of the International Bank for Reconstruction and Development (of the World Bank Group) (IBRD) / International Development Association (of the World Bank Group) (IDA) energy lending in LCR in 1991-2006 reflects the application of the World Bank's strategies and policies in the energy sector. The investment loans amounted to 52 percent of the total lending, but collapsed during the past 10 years. The development policy loans represented 38 percent,

Table 3.3: IBRD/IDA Investment Operations in the Energy Sector, All Regions (US$ million)

Region	*FY97*	*FY98*	*FY99*	*FY00*	*FY01*	*FY02*	*FY03*	*FY04*	*FY05*
Africa	179	362	130	176	198	617	326	399	523
East Asia and the Pacific	1,623	907	183	666	144	318	361	94	413
Europe and Central Asia	973	1,019	686	405	439	224	270	369	669
Latin America and the Caribbean	33	151	54	99	257	451	99	57	184
Middle East and North Africa	162	231	74	14		1			6
South Asia	76	728	364	343	746	521	151	131	63
Total Energy and Mining	3,046	3,398	1,491	1,703	1,784	2,132	1,207	1,050	1,858

Source: The World Bank, Energy Sector. <http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY>.

but during the last five years increased its participation to 70 percent, mainly due to two large operations in Brazil and the Dominican Republic. GEF operations represent only 4 percent of the portfolio, but have increased their participation steadily.

The structure of the lending program between areas in the energy sector has also changed substantially during the past 15 years. Electric power maintains about 60 percent participation while operations in oil and gas show a substantial reduction. Loans for RE have a small participation but show a steady increase (Table 3.4).

Table 3.4: IBRD/IDA Operations in the Energy Sector in LCR 1991-2006

		1991-95	*1996-2000*	*2001-06*	***Total***	%
Development Policy Loans	Loan Amount	443	26	803	**1,272**	38%
	Project Cost	1,793	356	2,806	**4,954**	29%
	Number of Projects	19	7	13	**39**	28%
Investment (IBRD/IDA)	Loan Amount	1,201	361	160	**1,723**	52%
	Project Cost	3,881	4,336	807	**9,023**	53%
	Number of Projects	26	16	23	**65**	47%
Guarantees (IBRD)	Loan Amount		144	40	**184**	6%
	Project Cost		2,032	200	**2,232**	13%
	Number of Projects		1	1	**2**	1%
Carbon Finance Grants	Loan Amount			23	**23**	1%
	Project Cost			400	**400**	2%
	Number of Projects			16	**16**	12%
Global Environment Project Grants	Loan Amount	10	29	94	**133**	4%
	Project Cost	23	163	302	**488**	3%
	Number of Projects	1	5	11	**17**	12%
Total	**Loan Amount**	**1,654**	**561**	**1,120**	**3,335**	**100%**
	Project Cost	**5,697**	**6,886**	**4,513**	**17,097**	**100%**
	Number of Projects	**46**	**29**	**64**	**139**	**100%**

(continued...)

(...Table 3.4 continued)

IBRD/IDA Operations in the Energy Sector in LCR – Loan Amounts in US$ Million (1991-2006)

	1991-95	*1996-2000*	*2001-06*	***Total***	%
Power	1,073	222	649	**1,945**	61%
Oil and Gas	424	276	63	**763**	24%
General Energy	130	7	233	**369**	12%
Renewable	17	27	49	**93**	3%
Energy Efficiency	0	0	9	**9**	0%
Total Energy and Mining	1,644	532	1,003	**3,179**	100%
Grants for Energy and Mining	10	29	117	**156**	

Source: Prepared by authors based on the World Bank´s data in Web page.

The shift of the World Bank's portfolio away from power generation in favor of sector reform and adjustment and T&D is evident if we examine the list of the largest World Bank loans in energy in the region (>US$100 mn) in 1991-2006. The largest energy infrastructure operations were approved in the early 90s (except for the support to the Brazil-Bolivia gas pipeline in the late 90s) and, recently, the largest operations are development policy loans (Table 3.5).

The World Bank's pipeline for energy projects in LCR in 2006-08 maintains the participation of policy loans and increases the participation of carbon offset and GEF projects to about 60 percent of the number of projects, an indication of the emphasis on clean energy, EE and rural energy projects (Table 3.6).

Table 3.5: IBRD/IDA Operations in the Energy Sector in LCR – Summary of Loans >100 US$ Million (1991-2006)

Project Name	*Country*	*Lending Instrument-type*	*Calendar Year Approved*	*Loan Amount (US$ million)*
Yacyreta Hydroelectric Project (02)	Argentina	Investment	1992	300
Energy Sector Reform Loan	Brazil	Development Policy Lending	2002	432
Guaranteed Note – Bolivia-Brazil Gas Pipeline	Brazil	Guarantee	2000	144
Hydrocarbon Transport and Processing Project	Brazil	Investment	1991	260
Gas Sector Development Project – Bolivia-Brazil Gas Pipeline	Brazil	Investment	1997	130
Power Market Development Project	Colombia	Investment	1995	249
Dominican Republic Power Sector Program – Second-generation Reforms	Dominican Republic	Development Policy Lending	2005	150
Electricity Privatization Adjustment Loan	Peru	Development Policy Lending	1994	113
Uruguay Power Transmission and Distribution Project	Uruguay	Investment	1995	125

Source: Prepared by authors based on the World Bank´s data in Web page.

Table 3.6: IBRD/IDA Energy Sector in LCR Operations in the Pipeline (2006-08) – Project Cost in US$

Product Line	*Instrument*	*No. Projects*	*Amount US$ mn*
Carbon Offset	Investment	9	NA
GEF	Investment	11	NA
IBRD/IDA	DPL	4	285
IBRD/IDA	Investment	9	219
Total		**33**	**504**

Source: Prepared by authors based on the World Bank´s data in Web page.
Note: NA=Not applicable.

Other Developing Agencies

Developing agencies provided strong support to the financing of energy projects in LCR with private participation during the sector reform process. Total financing in direct loans and guarantees in 1991-2005 amounted to US$6.8 bn, and total financing that was mobilized (including cofinancing by commercial banks and other agencies) is estimated at about US$11 bn.[36]

The World Bank Group was the main source of financing for these projects. IFC and MIGA provided financing and guarantees for about US$2.9 bn, resources that are additional to the US$3.3 bn provided by IBRD / IDA during the same period, mainly for projects executed by the public sector. The IADB group was the second source of financing, with US$2.4 bn, which is already included in the US$7.9 bn financing of this group to the energy sector. Other developing agencies contributed about 18 percent of the financing (Table 3.7).

The activities of other developing agencies: Corporación Andina de Fomento (CAF), Banco Centroamericano de Integración Económica (BCIE), Caribbean Development Bank (CariBank), U.S. Agency for International Development (USAID), GTZ and CIDA in the energy sector in LCR are discussed below.

CORPORACIÓN ANDINA DE FOMENTO

The main objective of CAF is regional integration and improving competitiveness, mainly financing infrastructure projects (transportation, telecommunications and energy), which amounted to 70 percent in the CAF's portfolio of about US$18 bn from 2001-05. In addition to loans, CAF provides guarantees, equity investments and banking and financial advisory services. CAF was instrumental in launching, in 2000, the Initiative for Regional

[36] Authors estimates using the Private Participation in Infrastructure Database, available at: < http: / / ppi.worldbank.org / >.

Table 3.7: Energy Projects with Private Participation in LCR – Lending by Multilateral Agencies

Agencies	*1991-95*	*1996-2000*	*2001-05*	***Total***	%
BCIE	37	107	119	**263**	4%
CAF	10	318	111	**439**	6%
CariBank	0	10	0	**10**	0%
EIB	77	244	189	**510**	7%
IADB Group	103	1,675	599	**2,377**	35%
IADB	94	1,629	599	**2,322**	
IIC	9	46	0	**55**	
WB Group	487	1,490	1,264	**3,240**	47%
IBRD	53	310	0	**363**	
IFC	351	279	718	**1,348**	
MIGA	83	900	546	**1,529**	
Total	**715**	**3,843**	**2,281**	**6,839**	**100%**

Source: Authors' calculations.

Infrastructure Integration of South America (IIRSA), also supported by IADB, which provides coordination mechanisms between countries to select priority projects and financing for selected projects. The current portfolio of projects under IIRSA is mostly road projects. As a percentage of CAF's total portfolio, energy projects amount to 6 percent, compared to 36 percent dedicated to transportation,[37] but increased from about US$500 mn in 1991-95 to about US$1,800 mn in 2001-05, and include large projects like the Brazil-Venezuela power transmission line (US$86 mn loan) and the Bolivia-Brazil gas pipeline (US$215 mn loan).

CARIBBEAN DEVELOPMENT BANK

The strategy of CariBank focuses on three thematic areas: infrastructure for sustainable development, sustainable communities, and regional economic integration in the Caribbean. CariBank has provided support recently to power generation and T&D projects in Anguilla and Belize. In 2005, energy projects received US$14.9 mn loans, 10 percent of the total new lending.[38]

[37] *CAF,* Annual Report 2005.
[38] CariBank, CDB Annual Report 2005.

BANCO CENTROAMERICANO DE INTEGRACIÓN ECONÓMICA

BCIE promotes poverty reduction and economic integration, and it aims at improving Central America's competitiveness in a global economic environment. BCIE gives priority to initiatives in power generation, infrastructure and sustainable development. In 2005, energy projects represented about 7 percent of the total lending of about US$1.7 bn.

THE U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT

The USAID energy program has the main objective of expanding access to modern energy services, and focuses on two main areas: energy market development (implementation of adequate policy, legal and regulatory reforms) and energy enterprise development (providing affordable, clean and reliable energy services to the poor).

In LCR, USAID is supporting mainly RE and EE programs. From 2000 to 2005, USAID provided US$5.3 mn in support of Facilitating Financing for Renewable Energy Program (Financiamiento de Empresas de Energía Renovable – FENERCA). This program was aimed at assisting policy reform, providing enterprise development services, business planning assistance and facilitating financing to encourage investment in renewable sources of energy. The target countries were Guatemala, El Salvador, Honduras, Nicaragua and Panama. FENERCA helped to create a US$15 mn fund for investment in clean energy known as the Central American Renewable Energy and Cleaner Production Facility. USAID also supports the Efficient Energy for Sustainable Development Partnership, a PPP led by the United States Department of Energy (USDoE), which aims to improve the productivity and efficiency of energy systems. Through this program, USAID has been active in Mexico, Guatemala and Brazil, supporting EE in the public sector, providing technical assistance for standards and labeling programs and rehabilitation of small hydropower facilities.

CANADIAN INTERNATIONAL DEVELOPMENT AGENCY

The CIDA strategy for the Americas has three main areas: governance, particularly reforms to support social, political and economic inclusion; economic productivity, including economic policy and private sector development; and basic human needs, especially primary education, Human Immunodeficiency Virus / Acquired Immune Deficiency Syndrome (HIV / AIDS), and basic health care. In the energy sector, CIDA supports OLADE's Sustainable Energy Project (US$4.8 mn during 2003-08), which aims to strengthen energy policy-making capacity and ensure sustainable energy development in South America.

GERMAN AGENCY FOR TECHNICAL COOPERATION

GTZ works on a broad range of topics, but its agenda in the energy sector is focused mainly on EE and RE. Ongoing projects in LCR include studies on RE and EE in Chile, a study to promote the use of RE sources on a large scale in Mexico, rural development in Bolivia, technical assistance in wind power through the Technical Expertise for Renewable Energy

Applications (TERNA) program, and support to the Caribbean Renewable Energy Development Program (CREDP), an initiative to remove the barriers to the use of RE and foster its development and commercialization. Funding for CREDP was ensured in 2004 (US$4.4 mn from GEF and US$2.2 mn from GTZ) to support the establishment of an enabling legal and regulatory framework, capacity-building in the region, demonstrating innovative financing mechanisms and creating a regional information network for the development of RE.

Potential Demand for the World Bank's Support

The analysis of the World Bank's lending program in energy in LCR during the past decade showed a shift away from large infrastructure investment projects in favor of development policy loans to support sector reform, and small loans to support carbon finance, rural energy, RE and EE programs.

A change in the investment climate in the energy sector – slowdown in private investment, withdrawal of strategic investors and difficulties with market reforms – prompted a review of the World Bank's strategy in promoting private sector development in electricity (The World Bank, 2005g) and its operational guidelines for the public and private sector roles in electricity supply (The World Bank, 2004d).

The review acknowledged, among other things, the complexity of the reform process, the need to adjust it to country-specific conditions, the need to address poverty reduction and environmental issues and the importance of country commitments.

The guidelines provide some sensible messages: any strategy for sustainable reform should address the fundamental issue that electricity revenues should be sufficient to cover the costs of supply, that the speed and course of the reform will vary from country to country, and that a full range of options should be considered – from pure public interventions to pure private – but that public-private approaches are appropriate for most countries.

The guidelines establish a flexible approach to financing. **In generation**, private financing is preferred, but public support in the form of guarantees or credit enhancement is critical to mobilize financing, and a strong public financing role may be vital in large hydroelectric projects. In **transmission,** there is a substantial role for public financing, provided that SOEs meet minimum corporate governance standards. Financial viability of distribution is the highest priority, and public financing can be provided to SOEs that work well or can improve performance; otherwise, concession and management contracts, and leases can be considered.

The Development Committee of the World Bank and the International Monetary Fund (IMF) issued a progress report on an investment framework for clean energy and development (The World Bank, 2006b) which proposes a strategy based on three pillars: (i) energy for development and access to the poor; (ii) energy for a low-carbon economy; and (iii) adaptation. The first pillar suggests that the financing gap to meet the energy for development and energy access agendas can be met by deepening energy sector policy reform to attract private sector investments and additional public sector financing. On the second, it concludes that the current support of IFIs and public and private resources are not sufficient for a meaningful transition to a low-carbon economy and that it is necessary to scale up existing instruments to reduce the development cost of clean technologies, create new financial instruments and to establish a global regulatory framework for emission reductions after 2012. On the third, it concludes that poverty alleviation programs are threatened by severe weather patterns and climate change, and that it is essential to increase the financial resources needed to support adaptation

The guidelines and the clean energy policy establish a general framework for the role of the World Bank in the energy sector, which is consistent with the four main challenges that should be addressed by the energy strategy in LCR (see page 141): energy security is enhanced by the development of RE, clean technologies and EE; access to the poor is included in the two agendas and is essential to improve the legitimacy of the sector reforms in the region; support to PPPs is essential to mobilize required financial resources; and improvements of the governance and regulatory frameworks are essential to decrease the financing gap.

The proposed energy strategy for LCR supports the clean energy policy with some differences in priorities. The main goal of the strategy is ensuring sufficient, efficient and sustainable energy supply to meet expected demand. The experience with energy reform in the region shows that wholesale markets were vulnerable to external shocks and had difficulties in keeping the lights on and maintaining stable electricity tariffs – two requirements to maintain the political survival of any government. Therefore, the energy strategy focus on diversification of energy sources and mobilizing financing, two instruments to ensure sufficient capacity and reduce vulnerability to external shocks. Although the diversification of energy sources in the region will result in substantial participation of clean power (about 83 percent) in new generation capacity additions for 2006-16, the existing financing mechanisms for clean power (carbon finance and GEF) will have a marginal impact. The small renewable power projects represent only 7 percent of clean power projects, and strong financing support will be required for the development of traditional power and oil and gas projects (medium and large hydroelectric and large cross-border gas interconnections projects). The World Bank´s support for the financing of these projects will also provide the leverage to allow the World Bank to play a substantive role in policy-making and energy mix choices.

The World Bank needs to shift the composition of its energy portfolio in LCR to help the countries face the new challenges. Although it is necessary to strengthen the existing carbon finance and GEF programs to support the development of RE, EE and rural energy, financing of traditional investment projects is a high priority, mainly power generation and regional energy trade.

Financing of Large Infrastructure Projects is Required

The region needs to develop about 36,000 MW in new generation capacity in 2009-15 in projects that are not well-suited for traditional nonrecourse project finance. These are medium and large hydroelectric projects, coal-fired generation plants and geothermal plants with high fixed costs, long construction and payback periods and usually long and unpredictable processes to obtain the required permits and licenses, a combination of factors that increase project and market risks for the developer and financial costs of the projects.

These are also least cost and necessary projects to meet expected demand and diversify the sources of supply, a high priority for many countries in the region. The development of small renewable projects is also necessary but in the best of circumstances would contribute less than 10 percent of the total generation by 2015.

Mobilizing financing would require the use of private financing models that fit the country and project risks, and improvements in the regulatory climate and the financial viability of the sector. PPPs, supported by guarantees and other forms of credit enhancement, are essential to reduce the project, market and country risks, reduce the financing costs and allow private investors to have an adequate risk-adjusted return on investment in these generation projects.

Improving the regulatory regime and the financial viability are essential to avoid the risk that these partnerships become a fiscal burden (mainly the use of sovereign guarantees when prices lag behind costs). Regardless of what ownership or market arrangements are used, the power sector is unlikely to be financially viable if electricity tariffs lag behind costs due to lack of political will or difficulties in covering the impact of high oil prices on generation costs, and if there is lack of political support to implement programs to reduce electricity losses and improve collections. The sector may not be financially viable if there are still poor performing State-owned Discoms that have a large market share. The World Bank support to PPPs with credit enhancement instruments for the implementation of generation projects is only an option in countries where the government supports a credible program to maintain or improve the financial viability of the sector.

Expand Energy Interconnections and Promote Regional Energy Trade

There is a great potential to increase energy trade in the region, reduce generation costs and diversify the energy sources. The SIEPAC project will be commissioned in 2009. A new transmission line between Colombia and Ecuador will be completed in 2007. An electricity interconnection between Colombia and Central America looks promising. Uruguay can benefit from a new power interconnection with Brazil.

However, many countries in the region are reluctant to depend on firm energy supply from cross-border trade. The energy crisis in Argentina and the renegotiations of gas supply contracts from Bolivia were a setback for the energy trade in the Southern Cone. The generation expansion plans in many countries in Central America are not taking into account regional trade as an option for firm supply of electricity.

There are several opportunities for the support of development banks:

- Provide financing for new electricity interconnections between Colombia and Central America;
- Support the preparation of a feasibility study of a regional generation project in Central America, which would sell energy in the regional market, help diversify energy supply and promote cross-border firm energy supply contracts in the region; and
- Support financing of a new power interconnection between Uruguay and Brazil to help to rebuild confidence in regional trade in the Southern Cone.

Step up Support to RE, EE and Rural Energy

A likely scenario of high oil prices, vulnerability to external shocks and climate change concerns have renewed the interest of all countries in the region to develop a large and untapped potential of small RE, mainly wind and biomass power, small hydro and biofuels. Many countries in the region have established special incentives, programs and targets for the development of RE by the private sector (for example, Brazil, Costa Rica and Honduras).

Development agencies have supported the development of RE in the past, but the expansion plans in many countries call for a substantial increase in the market share of RE, which requires scaling up the support by the World Bank in several areas:

- Finance studies to assess the potential of renewable resources, develop resource information systems and disseminate information;
- Provide long-term credits at preferential rates;
- Finance off-grid rural energy programs;
- Technical assistance to revise legal and regulatory frameworks and reduce barriers to the development of RE; and
- Step up carbon finance for RE projects.

Implementation of EE programs is a priority in a scenario of high oil prices and concerns about climate change. Mexico has shown that EE and conservation is an attractive and effective option to reduce dependence on imported fuels, reduce the cost of energy supply and reduce GHG emissions. There is an opportunity to step up the support that the development agencies have provided to EE programs.

World Bank support is needed for the implementation of high-priority rural energy programs mainly in countries in the region with medium and low electricity coverage (Bolivia, Honduras, Nicaragua, Ecuador and Peru). The World Bank has an important role to play in: (a) assisting the transfer of knowledge and development of rural electrification policies, financing mechanisms, appropriate construction and service standards and tariffs; (b) assisting development of RE options for rural electrification, especially sharing knowledge and approaches from best practices in developing countries; and (c) helping to finance the requirements for investment subsidy to be borne by the public sector, which are substantial as explained in page 144.

The World Bank is in a strong position to assist client countries in expanding electricity service to rural areas based on its reputation, global knowledge, long experience in the sector and available staff. The World Bank's comparative advantage is that it has assisted countries in developing models for rural electrification that aim to improve the economic efficiency of investments, explore alternative delivery methods that include PPPs and has good knowledge of available technologies and trends to optimize the costs of service provision.

Improving Corporate Governance of SOE and Consolidating Sector Reform

The public sector remains a major provider of electricity service in the region and poor performance of State-owned utilities is still an issue. SOEs in Ecuador, Honduras, the Dominican Republic, Guyana and Colombia are inefficient and do not generate sufficient cash to finance the required investment.

A new approach is needed to improve corporate governance of SOEs in these countries. Privatization is not a short-term option for political and practical reasons. Private operators have pulled out of some of these countries, and there is lack of appetite for foreign private participation in the divestiture of Discoms. There is political opposition to privatization in these countries. On the other hand, improving governance of SOEs without restructuring is not an option. Corporatization and participation of local shareholders may be the way forward in some countries.

The experience with the reform of the power market rules in 2004 in Brazil shows that despite the difficulties of wholesale power markets, the idea of renationalization and returning to the public sector model is not a valid option. Sector reforms are a process and developing agencies should continue supporting the establishment of strong regulatory institutions and second-generation market reforms in the region. One area of special interest is the design of efficient bidding mechanisms to award long-term energy supply contracts. This instrument is adopted in most countries to ensure sufficient generation capacity, facilitate financing of generation projects and mitigate the volatility of spot prices.

Oil and Gas

STEPPING UP TO THE POLICY AND INVESTMENT CHALLENGES

The World Bank Group has lost its balance in the scale and scope of its interventions in the oil and gas sector in the LCR over the past several years. Given the criticality of the region's energy sector issues and their macroeconomic and social linkages, it is vital that the rebalancing of the World Bank Group's oil and gas investment and sector work programs be addressed, if it is to engage effectively with its regional partners. In particular, the tenor and scale of its interventions in the oil and gas sector needs to be enhanced, without sacrificing the vital support efforts in the power sector, new RE technologies, EE and rural electrification programs.

In tailoring its interventions in oil and gas, the following are areas in which the World Bank Group has an important role to play:

- **Regional Cross-border Gas projects –** in particular, the Southern Cone Gas Integration project; the introduction of gas into Central America; and the ECGP project. Its support would address climate change; diversification away from oil; deepen both energy and regional integration efforts, through its advice in creating institutional structures to mitigate conflicts arising in cross-border projects, and its investment and guarantee instruments. Additionally, the World Bank can play an independent broker role in the preparation of inter-governmental agreements that are key instruments underpinning cross-border projects. The experience that the World Bank has gained in the Bolivia / Brazil gas pipeline as well as outside of the region such as in Mozambique / South Africa, Nigeria / Benin and Togo / Ghana would be of relevance;

- **Development of Gas Regulatory Practices –** supporting the further development of gas regulatory practices in targeted countries to enhance the expansion of incountry gas T&D networks and, eventually, the evolution of a competitive gas market;

- **Financing Refinery Modernization and Upgrading –** this is an area in which IFC would be well-positioned to support those projects which are structured as joint ventures between State and private companies. This implies that ex-refinery prices would reflect those at the international level and move in tandem with them; and

- **Modernize and Corporatize NOCs in Countries Willing to Engage –** this intervention would entail two separate components, through appropriate instruments. First, separate the institutional, contractual and regulatory roles of the State from those of the NOC which would focus on investment, production and commercial responsibilities. This would be followed by the commercialization and corporatization of the NOC and, after a period of satisfactory performance, offer shares on the local market, with the government retaining a golden share. Second, the removal of the "broad band" subsidies on petroleum products and gas with these being replaced by well targeted cash transfers to lower income groups, along the lines of what was successfully done in Indonesia.

Annex
Summary of Power Market Reforms

Table: Latin America and the Caribbean Region – Summary of Power Market Reforms

	Argentina	*Colombia*	*El Salvador*	*Brazil*	*Chile*	*Peru*
Installed Generation Capacity 2004 (MW)	28,185	13,398	1,105	90,733	10,737	6,016
Electricity Demand 2004 (GWh)	84,744	38,556	4,915	346,745	43,829	21,270
Reform Timing						
Law Enacted	1991	1994	1996	1995-98 (new market model in 2004)	1982	1992
Restructuring	1992-93	1995-99	1997-99	1995	1981	1994
Privatization				1995-2001	1986-89	1994-97
Industry Structure						
Unbundling	Separate G,T,D	Separate G,T,D for New Companies	Separate G,T,D	Separate G,T,D (affiliated companies allowed)	Separation of Accounts G,T,D	Separate G,T,D
Market Model	Wholesale Competition	Wholesale Competition	Retail Competition	Wholesale Competition	Wholesale Competition	Wholesale Competition
Market Participants						
Gencos	41	66	4	25	12	18
Self-generators and IPPs			10	89	6	
Transcos	57	11	1	54	4	6
Discoms	62	32	5 (two groups)	43	31	33
Marketers	46	67	5	42	0	0
Large Consumers	1,496 (21% of demand)	4,206 (31% demand)	5 (10% demand)	577 (21% demand)	30% Demand	46% Demand
Private Participation						
Generation	80%	57%	64%	26%	100%	66%
Transmission	100%	3%	0%	10%	100%	100%
Distribution	60%	46%	100%	64%	~100%	71%

(continued...)

(... Table continued)

	Argentina	*Colombia*	*El Salvador*	*Brazil*	*Chile*	*Peru*
Wholesale Market Arrangements						
Economic Dispatch	Cost-based Bids	Cost-based Bids	Price Bids	Centralized, Cost-based	Centralized, Cost-based	Centralized, Cost-based
Spot Transactions	Nodal Prices, Generators, LC	Single Node, G,D, LC	Single Node, G, D, LC	Nodal Prices G,D, LC	Nodal Prices, Generators	Nodal Prices, Generators
Capacity Charges	Yes	Yes	Yes		Yes	Yes
Large Consumers	5MW, Reduced to 30 kW	2 MW, Reduced to 100 kW	Full Retail Competition	10 MW, Reduced to 500 kW	2 MW, Reduced to 500 kW	1 MW
Long-term Contracts	Negotiated	Negotiated	Negotiated	Competitive Tender by Central Agency for 100 percent Demand-regulated Market. Negotiated for Market of Large Consumers	Negotiated	Negotiated
Transmission Expansion	Negotiated Third Party Access	Central Planning	Central Planning	Central Planning	Negotiated Third Party Access	Negotiated Third Party Access
Prices to Regulated Consumers	Average of Seasonal Spot Prices	Moving Average of Spot and Contract Prices	Average of Spot Prices	Weighted Average of Spot and Contract Prices	Average of 48-month Expected Marginal Costs	Average of 48-month Expected Marginal Costs
Institutional Arrangements						
Policy-making	Ministry of Energy	Ministry of Energy	Ministry	Ministry	Ministry	Ministry of Energy
Expansion Planning		Agency of ME	None	Special Agency (EPE)	CNE, Gov. Participation	
Regulation	ENRE, Independent	CREG, Government Participation	SIGET, Independent	ANEEL, Independent		OSINERG, Independent
Market Administration	ISO, CAMMESA	Business Unit of T	ISO, UT	ISO, ONS, CCEE	ISO, CDEC	ISO, COES
Major Market Changes	Intervention of Market Prices in 2002		Changed to Cost -based Bids in 2006	After Energy Crisis of 2001, a New Market Model was Adopted in 2004 to Strengthen Central Planning, Long-term Contracts and Energy Security	Ley Corta I, II of 2004 and 2005, Introduced Incentives for Generation and Transmission Expansion.	

(continued...)

(... Table continued)

	Bolivia	Dominican Republic	Guatemala	Nicaragua	Panama
Installed Generation Capacity 2004 (MW)	1,450	3,290	2,016	756	1,583
Electricity Demand 2004 (GWh)	3,779	12,163	6,216	1,719	4,656
Reform Timing					
Law Enacted	1994	2001	1996	1998	1997
Restructuring	1994-95	1997	1996-98	1999	1998
Privatization		1999		2000-02	1998
Industry Structure					
Unbundling	Separate G,T, D	Separate G,T, D (T and Ghid are bundled)	Separate G,T, D (T and Ghid are bundled)	Separate G,T, D	Separate G,T, D
Market Model	Wholesale Competition	Wholesale Competition	Wholesale Competition	Wholesale Competition	Wholesale Competition
Market Participants					
Gencos	8	11	10	9	8
Self-generators and IPPs		2	12	1	10
Transcos	2	1	1	1	1
Discoms	6	3	3+13 (small municipal)	1	3
Marketers	0	0	7	0	0
Large Consumers	2		32% Demand	9 (8% demand)	5 (2% demand)
Private Participation					
Generators	100%	83% (Ghid reserved to SOE)	68%	69% (Ghid reserved to SOE)	89%
Transmission	100%	0% (T reserved to SOE)	0%	0% (T reserved to SOE)	0% (T reserved to SOE)
Distribution	93%	32%	91%	~100%	100%

(continued...)

(... Table continued)

Wholesale Market Arrangements					
Economic Dispatch	Centralized, Cost-based	Centralized, Cost-based	Centralized, Cost-based	Centralized, Cost-based	Centralized, Cost-based
Spot Transactions	Nodal Prices, Generators	Single Node, G, D	Single Node, G, D	Single Node G, D	Single Node, G, D
Capacity Charges	Yes	Yes	Yes	Yes	Yes
Large Consumers	1 MW	2 MW Reduced to 200 kW	100 kW	2 MW	100 kW
Long-term Contracts	Discoms Must Tender for 80% Demand	Discoms Must Tender for up to 80% Demand	Competitive Bidding	Discoms Must Tender for 80% Demand	Discoms Must Tender for 100% Demand
Transmission Expansion	Negotiated Third Party Access	Central Planning	Central Planning	Central Planning	Central Planning
Prices to Regulated Consumers	Average of Expected Marginal Costs	Weighted Average of Spot and Contract Prices	12-month Weighted Average of Spot and Contract Prices	12-month Weighted Average of Spot and Contract Prices	Weighted Average of Spot and Contract Prices
Institutional Arrangements					
Policy-making	Ministry of Energy	CNE, Government Participation	Ministry of Energy	CNE, Government Participation	CNPE, Government Participation
Expansion Planning					
Regulation	SIRESE, Independent	SIE, Independent	CNEE, Attached to Ministry	INE, Independent	ERSP, Independent
Market Administration	ISO, CNDC	ISO, OC	ISO, AMM	Business Unit of T	Business Unit of T
Major Market Changes		Private Investor with 68% Participation in Discoms Pull Out in 2003		Private Investor with 100 % of Discoms in Serious Difficulties	

(continued...)

(... Table continued)

	Honduras	Ecuador	Uruguay	Costa Rica	Mexico	Venezuela R.B. de
Installed Generation Capacity 2004 (MW)	1,041	3,541	2,169	1,961	52,979	22,124
Electricity Demand 2004 (GWh)	4,110	10,735	6,260	6,824	158,094	68,097
Reform Timing						
Law Enacted	1994	1996	1997	1990	1992 Amendment to 1975 Electricity Law	2001
Restructuring	None	1997-99	2002-	No	No	No
Privatization	IPPs (1994-)	No	Small Renewable IPPs (2006-)	Small Renewable IPPs (1994-)	IPPs (1994-)	
Industry Structure						
Unbundling	Vertically Integrated Monopoly and IPPs	Separate G,T, D	Vertically Integrated Company, Separation of Accounts	Vertically Integrated Monopoly and Small Municipal and Cooperatives	Vertically Integrated Monopoly	Vertically Integrated Monopolies
Market Model	Single Buyer	Wholesale Competition	Wholesale Competition	Monopoly G/T/D, Licensed Small IPPs are Permitted	Monopoly G/T/D, Licensed IPPs and Cogenerators are Permitted	Power Pool
Market Participants: Gencos	1	13	2	1	1	
Self-generators and IPPs	22	16	1	4 Small Cooperatives and Municipalities, 30 Small Renewable IPPs	403 Power Stations (362 self-generators, 18 IPP, 36 Co-generators)	7 Vertically Integrated Monopolies, 2 D, 4 G
Transcos	1	1	1	1	1	
Discoms	1	20	1	1+6 Small Municipal and Cooperatives	1	
Marketers	0	0	0	0	0	0
Large Consumers	1 (2%)	11% of Demand	0	0		
Private Participation						
Generation	65%		0%	12% (small renewables)	19% (only IPPs)	14%
Transmission	0%	0%	0%	0%	0%	
Distribution	0%	0%	0%	0%	0%	

(continued...)

(... Table continued)

Wholesale Market Arrangements						
Economic Dispatch	Centralized, Cost-based	Centralized, Cost-based	Centralized, Cost-based			Centralized
Spot Transactions	No	Nodal prices, G, D, LC	Law of 1997 Established Wholesale Power Market, with Spot Transactions and Long-term Contracts, and Large Consumers > 250 kW, Similar to Argentina, to Facilitate Integration with that much Larger Market. However, the Economic and Energy Crisis in Argenti	Vertically Integrated Market and Small Municipal Companies and Cooperatives. ICE Purchase Energy From IPPs at Avoided Cost under Long-term Contracts	Vertically Integrated Market. Laws Allows IPPs, Cogenerators and Self-generators under License. CFE Purchase Energy from Licensed IPPs under Long-term Contracts and Excess Power From Cogenerators and Self-generators	A Regulated Power Pool of Vertically Integrated Companies is in Operation, Until a 2001 Law that Creates a Wholesale Market is Implemented
Capacity Charges	No	Yes				
Large Consumers	1 MW	1 MW				
Long-term Contracts	with Single Buyer, Competitive Tender	Negotiated, Initial Contracts with Hydros for 100% Generation				
Transmission Expansion	Central Planning	Central Planning				
Prices to Regulated Consumers	Expected Marginal Costs	4 Year Average of Expected Marginal Costs				
Institutional Arrangements						
Policy-making	Dispersed	Ministry	Ministry	Ministry	Ministry	Ministry
Expansion Planning	SOE	CONELEC, Independent	URSEA, Independent, Does not Approve Tariffs	SOE ARESEP, Independent	CRE, Independent, Does not Approve Tariffs	Government Office, FUNDELEC. Provisional
Regulation	CNE, Independent					
Market Administration	No Market	ISO, CENACE	ISO, ADME, Has not Assumed Functions	SOE	SOE	OPSIS, Power Pool
Major Market Changes	1994 Law Established Unbundling, but was not Applied	Initiatives to Privatize Gencos and Discoms Failed. Tariffs do not Reflect Costs and Wholesale Market of SOE is Beseiged by Nonpayment in the Supply Chain	Wholesale Market Model is being Revised. Priority Given to Security of Energy Supply and Developing Renewable Generation with Private Participation. Operating as a Single Buyer Model			Law of 2001 (LOSE) Established a Wholesale Market, Unbundling, Large Consumers, Independent Regulator and Market Administrator. It has not been Implemented

Source: Authors´calculations.

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