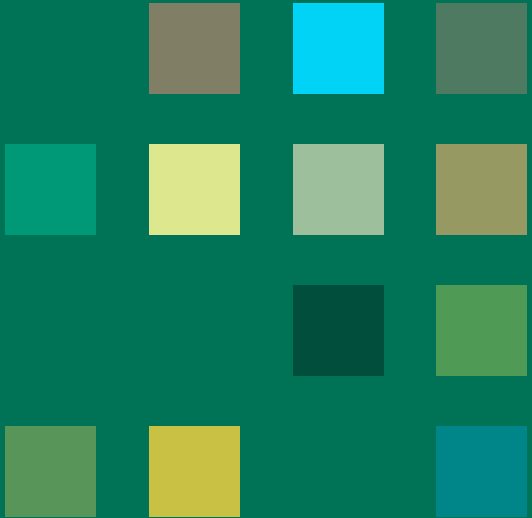


Report No. 53719—PE

PERU:

Overcoming the Barriers to Hydropower



Energy Unit
Sustainable Development Department
Latin America and the Caribbean Region
The World Bank

PERU:

Overcoming the Barriers to Hydropower

May 2010

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance trust fund program administered by the World Bank and assists low- and middle-income countries to increase know-how and institutional capability to achieve environmentally sustainable energy solutions for poverty reduction and economic growth.

Energy Sector Management Assistance Program (ESMAP) reports are published to communicate the results of ESMAP's work to the development community with the least possible delay. Some sources cited in this paper may be informal documents that are not readily available.

The report is a product of the staff of the International Bank for Reconstruction / The World Bank. The findings, interpretations, and conclusions expressed in this report do not necessarily reflect the views of the Executive Directors of the World Bank or the governments they represent, or ESMAP. The World Bank and ESMAP do not guarantee the accuracy of the data included in this publication and accepts no responsibility whatsoever for any consequence of their use. The boundaries, colors, denominations, other information shown on any map in this volume do not imply on the part of the World Bank Group any judgment on the legal status of any territory or the endorsement of acceptance of such boundaries.

TABLE OF CONTENTS

Foreword	vi
Abbreviations and Acronyms	vii
Acknowledgments	x
Executive Summary	xi
1. Study Objectives and Background	1
1.1 Context and Sector Objectives	2
1.2 New Energy World	5
2. Technical Viability of Hydropower	8
2.1 Technical Viability and Preparedness of Hydropower Projects in Peru	8
2.1.1 Hydropower Potential Development and Challenges	8
2.1.2 Technical Assessment and Review of Costs	12
2.2 Climate Change Considerations.....	16
2.3 Social and Environmental Issues	19
2.4 Hydrometeorological Information	22
2.5 Conclusions of the Technical Assessment	24
3. Economic Rationale of Hydropower Development: Economic Analysis	27
3.1 Methodology	27
3.2 Natural Gas Prices in Peru	28
3.3 Economic Value of Natural Gas Based on Netback Values	28
3.4 The Economics of Electricity Generation in Gas-fired Plants	30
3.5 Economic Analysis of the Sample Projects	34
3.6 Local Environmental Benefits	37
3.7 Global Environmental Benefits.....	38
3.8 The Negative Impacts of Climate Change	39
3.9 Conclusions on Economic Analysis of Hydropower Projects	40
4. Financial Viability of Hydropower	43
4.1 Assumptions for Financing of Projects.....	43
4.1.1 Assumptions for Long-term Commercial Financing of Projects	43
4.1.2 Equity Returns Required on Hydropower Projects.....	46
4.1.3 Other Assumptions for Financial Analysis of Hydropower Projects.....	46
4.2 Financial Internal Rate of Return (FIRR) for the Typical Project under Recent Market Conditions	47
4.3 Analysis of the Financial Viability of Hydropower Projects under Different Financing Scenarios	50
4.3.1. Commercial (balance sheet) Finance	50
4.3.2 Project Finance.....	52
4.3.3 Development Bank Financing.....	54
4.3.4 Blended Finance: IFIs and Commercial Banks	55
4.3.5 Public Sector Project with IFI Financing.....	58
4.3.6 Comparison of Scenarios	59
4.3.7 Sensitivity of Scenarios to Assumptions.....	61
4.4 Impact of Carbon Finance on Financial Viability of Projects	62
4.5 Financing Hydropower Projects: Risks and Mitigating the Risks	64
4.5.1 Price Risk	65

4.5.2	Completion Risk	65
4.5.3	Hydrology Risk.....	65
4.5.4	Operational Risk	66
4.5.5	Off-take Risk.....	66
4.6	Impact of the Global Financial Crisis on Financing Hydropower Projects ..	66
4.7	Conclusions on Financial Viability of Hydropower Development in Peru ..	68
5.	Enabling Framework: Licensing of Hydropower Investments and Water	
	Rights Management	71
5.1	Concessions for Hydropower Plants	71
5.1.2	Definitive Concessions	71
5.1.3	Other Requirements at the Local Level	72
5.2	Water Rights	73
5.3	Current Procedures for Environmental and Social Impact Assessments.....	75
5.3.1	Environmental Impact Study	76
5.3.2	River Basin Management Plan (<i>Planes de Manejo de Cuenca</i>).....	76
5.4	Rights of Way	76
5.4.1	Current Issues and Concerns.....	77
5.5	Certification of Nonexistence of Archeological Remains	77
5.6	Legal Framework for Foreign Investments in Power Generation.....	78
5.7	Conclusions and Recommendations	78
6.	Enabling Framework: Regulatory System and Auctions.....	81
6.1	Overview of the Electricity Sector in Peru	81
6.1.1	Market Structure	81
6.1.2	Electricity Supply.....	83
6.1.3	Electricity Demand	85
6.2	Price Regimes for Generation.....	86
6.2.1	Direct Sales to Large Consumers.....	86
6.2.2	Electricity Tariffs and Prices in the Regulated Market.....	87
6.3	Power Generation and Natural Gas Policies	92
6.4	The Peruvian Supply Auction System	94
6.4.1	Hydropower and the Auctions System	98
6.5	Sector Investments and Private Participation.....	101
6.6	Issues and Government Reactions	103
6.7	Conclusions.....	107
7.	Conclusions and Policy recommendations.....	110
7.1	The Potential Contribution of Hydropower in Peru.....	110
7.2	Barriers to the Development of Hydropower.....	111
7.3	Recommendations for a Coherent Strategy in Support of Hydropower	113
7.3.1	Stronger Role of the State is Essential	113
7.3.2	Development of the Amazon Basins for Exports to Brazil.....	117
	Bibliography.....	148

ANNEXES

Annex 1: Impact of Climate Change on Hydropower

Annex 2: Recommended Measures to Strengthen the Current Hydrometeorological Network

Annex 3: Avoided Cost Approach: Sample Calculation for a Typical Project

Annex 4: Procedures for the Licensing of Hydropower Projects

Annex 5: Electricity Auctions in other South American Countries

TABLES

Table 2.1: Hydropower Theoretical and Technical Potential

Table 2.2: Hydropower Installed Capacity by Regions

Table 2.3: Current Definitive and Temporary Concessions

Table 2.4: General Characteristics of the Projects Assessed

Table 3.1: Natural Gas Prices (Pipeline) 2008

Table 3.2: 2008 Regulated Gas Prices for Thermal Power Generation in Lima Area

Table 3.3: Economic Value of Natural Gas

Table 3.4: 140-MW Combined Cycle Plant

Table 3.5: 150-MW Open-Cycle Plant

Table 3.6: OSINERGMIN Capacity Charges Calculation

Table 3.7: Generation Costs at 65 Percent Load Factors

Table 3.8: Potential Impact of Reduced Dry Season Flows on the Typical Project

Table 4.1: Six-month LIBOR

Table 4.2: Depreciation Rates

Table 4.3: Results of Financial Cost-Benefit for the Typical Project, Commercial Financing

Table 4.4: Balance Sheet Financing

Table 4.5: Project Finance

Table 4.6: Brazilian Model Development Bank Financing

Table 4.7: Blended IFI and Commercial Banks

Table 4.8: Public Sector Project with IFI Finance

Table 4.9: Comparison of Financing Scenarios: Firm Energy Bid Price Required for Financial Viability

Table 4.10: Total Financial Price to Meet Revenue Requirements

Table 4.11: Impact of Project Capital Cost Increases

Table 4.12: Sensitivity to Capital Costs and Target FIRR for Typical Project, Balance Sheet Finance, Total Financial Price

Table 4.13: Sensitivity to Capital Costs and Target FIRR for Blended IFI + Commercial Finance Terms, Total Financial Price

Table 4.14: Impact of Carbon Revenue on Electricity Price

Table 4.15: The Clean Development Mechanism Market

Table 4.16: The EU Market

Table 5.1: Concessions and Water Licensing Processes

Table 6.1: Periods of Contracts in the Free Market

Table 6.2: Evolution of Average Electricity Prices, 1998–2008

Table 6.3: Auctions during the Transitory Period, 2006–09

FIGURES

- Figure 1.1: European Climate Exchange Prices
- Figure 1.2: U.S. Gas Prices
- Figure 3.1: Demand Curve for Natural Gas
- Figure 3.2: Generation Costs Compared to Gas and Oil Prices
- Figure 3.3: OCCT Compared to CCCT Generation Costs, Present Gas Price
- Figure 3.4: OCCT Compared to CCCT Generation Costs, Present Gas Price
- Figure 3.5: Benefits of the Sample Projects Compared to Ratio of Firm to Installed Capacity
- Figure 3.6: The Hydro Project Supply Curve – Electricity Production Costs of Hydropower Plants Compared to Production Costs Natural Gas
- Figure 3.7: Supply Curve (as Economic Rate of Return)
- Figure 3.8: Productions Costs and Economic Rate of Return
- Figure 3.9: Impact of a 20 Percent Increase in Capital Costs
- Figure 3.10: Impact of Avoided GHG Emission Benefits on ERR
- Figure 3.11: Annual Peak and Off-peak Generation, Typical Project
- Figure 4.1: Peruvian Yield Curve
- Figure 4.2: U.S. Treasury Yield Curve (January, 2009)
- Figure 4.3: Regulated Market Energy Prices Compared to Marginal Energy Costs: Peak Hours
- Figure 4.4: Developer Annual Cash Flows, Commercial Financing
- Figure 4.5: Impact of Longer Loan Tenors on Total Financing Energy Price
- Figure 4.6: Supply Curve, Total Financial Cost to Meet 17.5 Percent FIRR
- Figure 4.7: DSCR and Cash Flows for a Typical Project: Project Financing
- Figure 4.8: Refinancing Arrangements in Vietnam under World Bank Renewable Energy Development Project
- Figure 4.9: Exchange Rate Variations
- Figure 4.10: DSCR, Typical Project: Blended IFI and Commercial Banks
- Figure 4.11: Supply Curve Based on Sample Projects: Balance Sheet Finance and Blended IFI + Commercial Banks
- Figure 4.12: Impact of Carbon Finance on Required Total Financial Price, Balance Sheet Finance
- Figure 6.1: Peruvian Electricity Market Structure
- Figure 6.2: Evolution of System Supply/Production, 1998–2008
- Figure 6.3: Prices in the Free Market in 2008
- Figure 6.4: Curve of Generation Energy Price Compared to Power Demand for Dry Season
- Figure 6.5: Evolution of Average Electricity Prices, 1998–2008
- Figure 6.6: 2008 Monthly Average Energy Marginal Price and Tariff
- Figure 6.7: Public and Private Generation Investments, 1995–2008

BOXES

Box 2.1: The Nam Theun 2 Hydropower Project in Lao PDR: Lessons from a New Business Approach

Box 3.1: Tariff Impacts of Raising the Gas Prices to its Economic Level

Box 4.1: Equity Returns

Box 4.2: A Typical Project

Box 5.1: the New Water Law

Box 6.1: Reserve Margin

FOREWORD

Hydropower can be an economically and environmentally attractive option for meeting electricity demand while moving toward the development of a low carbon economy. There are, however, particular challenges associated with sustainable hydropower development including: (i) the need to assess the combination of environmental, social and economic costs and benefits generated by each project; (ii) the need to plan at project, basin, country and sometimes regional levels; (iii) the need to build consensus among multiple stakeholders that are provided with adequate knowledge and skill; (iv) the need to manage inherent risks sometimes including limited hydrological data and analysis; and (v) the need to mobilize financing to cover high capital costs.

Traditionally, hydropower has been the major source of electricity in Peru, supplying more than 80 percent of electricity requirements. However, the share of hydropower in electricity generation has declined in recent years with the development of Peru's indigenous natural gas resources. Today, with the combination of a rapidly increasing electricity demand, increased attention to domestic energy security and the impacts of climate change, and the potential of developing projects for both domestic and export markets, hydropower development is again at the center of energy policy in Peru.

The *Overcoming Barriers to Hydropower Study* looks at the challenge of hydropower specifically in the Peruvian economic and energy context. The strategic issues examined and the report's conclusions are also of value to other countries with significant hydropower potential and the desire to make optimal use of this important source of clean energy.

In parallel to the study on hydropower development, the World Bank is conducting a study in Peru on *Assessment of Impacts of Climate Change on Mountain Hydrology: Development of a Methodology through a Case Study*. We believe that the combination of these two studies will make a valuable contribution to the dialogue on sustainable hydropower development in Peru and elsewhere.

Philippe Benoit
Sector Manager
Energy Unit
Latin America and Caribbean Region
Sustainable Development Department

ABBREVIATIONS AND ACRONYMS

ANA	National Water Authority (<i>Autoridad Nacional del Agua</i>)
ANEEL	Brazilian Electricity Regulatory Agency (<i>Agencia Nacional de Energía Eléctrica</i>)
ATR	Water Technical Administration
BNDES	Brazilian National Development Bank (<i>Banco Nacional de Desenvolvimento Econômico e Social</i>)
BOOT	Build, own, operate, transfer
BTU	British Thermal Unit
CAO	(<i>Oficina del Asesor en Cumplimiento</i>)
CCGT	Combined cycle gas turbine
CCX	Chicago Climate Exchange
CDM	Clean Development Mechanism
¢	Monetary sign for U.S. cent(s)
CER	Certified Emission Reduction
CIRA	Certificate of Nonexistence of Archaeological Remains (<i>Certificado de Inexistencia de Restos Arqueológicos</i>)
CIRR	Consensus commercial interest rate
CMSE	Electric Sector Monitoring Committee (<i>Comité de Monitoreo del Sector Eléctrico</i>)
COES	System Economic Operation Committee (<i>Comité de Operación Económica del Sistema Interconectado</i>)
CONE	Cost of New Entry
CO ₂	Carbon dioxide
CREG	(<i>Comisión de Regulación de Energía y Gas</i>) (Colombia)
DCA	Descending clock auction
DGAAE	General Directorate for Energy Environmental Matters (<i>Dirección General de Asuntos Ambientales Energéticos</i>)
DGE	General Directorate for Electricity (<i>Dirección General de Electricidad</i>)
DIA	Environmental Impact Declaration (<i>Declaración de Impacto Ambiental</i>)
DSCR	Debt Service Cover Ratio
ECL	Electric Concessions Law DL 25844 of 1992
ECX	European Carbon Exchange
EIS	Environmental Impact Study (<i>Estudio de Impacto Ambiental</i>)
EPC	Engineering, Procurement, and Construction
EPE	Energy Research Company (<i>Empresa de Pesquisa Energética</i>)
ERR	Economic rate of return
€	Euro
EU	European Union
FIDIC	International Federation of Consulting Engineers
FIRR	Financial Internal Rate of Return
FOREX	Foreign exchange
FOSE	Electricity Compensation Fund (<i>Fondo de Compensación Social Eléctrica</i>)
GDP	Gross domestic product

GHG	Greenhouse gas
GOP	Government of Peru
GPPS	Geothermal power plants
GRP	Main System Guarantee (<i>Garantía de Red Principal</i>)
GTZ	German Technical Assistance (<i>Deutsche Gesellschaft für Technische Zusammenarbeit</i>)
GWh	Gigawatt-hour
ICSID	International Centre for Settlement of Investment Disputes
IFI	International Financial Institution
IGN	National Geographic Institute (<i>Instituto Geográfico Nacional</i>)
INADE	National Institute for Development (<i>Instituto Nacional de Desarrollo</i>)
INC	National Institute of Culture (<i>Instituto Nacional de Cultura</i>)
INGEMMET	Geologic Mining and Metallurgic Institute (<i>Instituto Geológico Minero y Metalúrgico</i>)
INRENA	National Institute for Natural Resources (<i>Instituto Nacional de Recursos Naturales</i>)
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
kg	Kilogram
km	Kilometers
kW	Kilowatt
kWh	Kilowatt-hour
LEC	Electric Concessions Law (<i>Ley de Concesiones Eléctricas</i>)
LIBOR	London Interbank Offer Rate (interest rate)
LNG	Liquefied natural gas
M ³	Cubic meters
MEF	Ministry of Economy and Finance (<i>Ministerio de Economía y Finanzas</i>)
MEM	Ministry of Energy and Mines (<i>Ministerio de Energía y Minas</i>)
Mm	Million
MMCFD	Million cubic feet per day
MME	Ministry of Mines and Energy (of Brazil)
MoF	Ministry of Finance
MW	Megawatt
MWh	Megawatt-hour
NG	Natural gas
NGOs	Nongovernmental organizations
NO _x	Nitrogen oxide
NT2	Nam Theun 2 Project (in Lao PDR)
O&M	Operation and maintenance
OCCT	Open cycle combustion turbines
OECD	Organisation for Economic Co-operation and Development
OEF	Firm Energy Obligations (<i>Obligaciones de Energía Firme</i>)
OSINERGMIN	Supervisory Commission for Investment in the Energy and Mining Sector (<i>Organismo Supervisor de la Inversión en Energía y Minería</i>)

PHI-LAC	International Hydrological Program for Latin America (<i>Programa Hidrológico Internacional para América Latina</i>)
PMA	Environmental Management Plan (<i>Plan de Manejo Ambiental</i>)
PPA	Power Purchase Agreement
PROINFA	Programme of Incentives for Alternative Electricity Sources (<i>Programa de Incentivo a Fontes Alternativas de Energía Eléctrica</i>) (Brazil)
RR	Revenue requirements
SEIN	National Grid (<i>Sistema de Interconectado Nacional</i>)
SENAMHI	National Meteorology and Hydrology Service (<i>Servicio Nacional de Meteorología e Hidrología</i>)
TGP	(<i>Transportadora de Gas del Perú</i>)
TUPA	Unified Text for Administrative Procedures (<i>Texto Único de Procedimientos Administrativos</i>)
UIT	(<i>Unidad Impositiva Tributaria</i>)
UNESCO	United Nations Education, Scientific and Cultural Organization
UTM	(<i>Universal Transversal Mercator</i>)
VAD	Distribution Tariff (<i>Valor Agregado de Distribución</i>)
VAT	Value-added tax
VNG	Vehicular natural gas

ACKNOWLEDGMENTS

The Study was carried out by the World Bank with financing from the World Bank's Energy Sector Management Assistance Program (ESMAP) and Special Climate Change and Clean Energy Fund.

The authors would like to thank the authorities of the Ministry of Energy and Mines for their help and support, including Minister Dr. Pedro Sánchez Gamarra, Vice Minister of Energy Sr. Ing. Daniel Camac Gutiérrez and the Director General for Electricity Sr. Ing. Ismael Aragon, as well as their predecessors Sr. Arq. Juan Valdivia Romero, Dr. Pedro Gamio Aita and Ing. Jorge Aguinaga Diaz, respectively, as well as the Director for Electricity Concessions Sr. Ing. Mardo Mendoza.

The report was prepared by Enrique Crousillat (Lead Author) and Susan V. Bogach (Task Manager), with assistance from Terence Muir (Chapter 2), Julio Bustamante (Chapter 2), Peter Meier (chapters 3 and 4), Paula Corces-Grieve (Chapter 5), Eduardo H. Zolezzi (Chapter 6) and Enrique Millones (environmental issues). Janina Franco assisted in reviewing and editing of the final draft of the main report.

The report was prepared under the guidance of Laura Tuck, Carlos Felipe Jaramillo and Philippe Charles Benoit. Reviewers of the document within the World Bank included Michel Kerf, Luiz T.A. Maurer, Pedro Antmann, Juan Miguel Cayo and Luis Andres.

The report also benefited from comments and suggestions from representatives of the Ministry of Economy and Finance, the Ministry of Energy and Mines, the Supervisory Commission for Investment in the Energy and Mining Sector (OSINERGMIN), the System Economic Operation Committee (COES), PROINVERSION, and Electroperu during a consultation event where preliminary findings were presented on October 29, 2008 and on May 12, 2009.

The financial and technical support by the Energy Sector Management Assistance Program (ESMAP) is gratefully acknowledged. ESMAP – a global knowledge and technical assistance partnership administered by the World Bank and sponsored by official bilateral donors- assists low- and middle-income countries, its “clients,” to provide modern energy services for poverty reduction and environmentally sustainable economic development. ESMAP is governed and funded by a Consultative Group (CG) comprised of official bilateral donors and multilateral institutions, representing Australia, Austria, Canada, Denmark, Finland, France, Germany, Iceland, the Netherlands, Norway, Sweden, the United Kingdom, and the World Bank Group.

EXECUTIVE SUMMARY

i. Hydropower has been the major source of electricity in Peru, traditionally supplying more than 80 percent of electricity requirements, and serving as a source of independent generation for major mines and industries. With the development of natural gas in the early 1990s, and the opening of the Camisea pipeline, the Government of Peru's (GOP's) attention turned to providing incentives for the use of natural gas in power generation. This resulted in a virtual moratorium on hydropower development as a result of the very low price of natural gas (below economic cost). With the development of export markets for gas and increased attention to the impacts of climate change, the Government has recently begun to pay renewed attention to hydropower. Recent developments include: (a) introduction of accelerated depreciation for hydropower investments; (b) introduction of a "discount" to permit hydropower to compete with gas-fired plants in auctions; and (c) announcement of a special hydropower auction to be held in 2009 by ProInversión, the state agency for promoting private investment.

ii. The intention of this report is to assist the GOP in assessing the potential role of hydropower in the sector and the measures that could be taken to encourage its continued development as appropriate. The study was done at a particularly challenging time. First, there was considerable volatility in energy prices and investment costs, which needed to be incorporated into the analysis. Second, financial markets were in disarray and it was difficult to predict when conditions were likely to normalize. Third, the GOP recently introduced many new policies and regulatory measures through supreme decrees that are changing the regulatory system and may interact in unexpected ways.

iii. The main government counterpart for this study was the Ministry of Energy and Mines (MEM), which requested assistance from the Bank to help mobilize investment in hydropower. The present study was done following a broad participatory process that involved multiple interviews with all relevant stakeholders (including government agencies, the sector regulator, generating companies, distribution companies, project developers, professional organizations, and other multilaterals) plus a main consultation event.

iv. The major conclusions and recommendations of the report are presented below.

1. The Potential Contribution of Hydropower in Peru

v. A multi-perspective assessment of the potential contribution, and barriers, associated to the development of hydropower in Peru arrives at the following conclusions:

vi. **While the financial crisis may introduce a temporary slowdown, the Peruvian energy sector will face a difficult challenge to cope with rapidly increasing demand.** An indication of the gravity of the problems is that, for the first time since the sector reform, there have been significant power outages due to congestion in the

transmission system, capacity limitations in the Camisea gas pipeline, low hydroelectric generation, and lack of adequate reserve, all problems that require urgent attention. This situation will persist until new generation comes on line. If no new gas supply is available, or it is limited, natural gas-fired thermal generation will peak in 2012–14. Accordingly, an important part of the additional generation would have to come from other sources, mainly hydropower.

vii. **The technical assessment concludes that there are hydropower projects in western basins (more than 1,000 megawatts [MW]) with definitive concessions that are technically sound, could start construction shortly and, if so, could be commissioned by or around 2013–14.** The preparation of these projects, mostly low impact run-of-river, is supported by good basic information and capable national expertise. In fact, these projects, plus others of similar characteristics that are currently in an earlier state of preparation, constitute one of the main options available to the country for developing a low carbon economy.

viii. **A set of hydropower projects with temporary concessions (adding an additional 4,300 MW) could contribute to meeting power demand from 2015 onward.** In addition, the potential for development of hydropower in eastern basins surpasses the country's power requirements and offers an opportunity for export to neighboring countries. However, the knowledge of this potential is less advanced and the social and environmental consequences are greater.

ix. **While a preliminary assessment of the impact on the glaciers' recession suggests that this could be limited, the impact of climate change on hydropower in Peru is uncertain.** There are a limited number of projects that feed significantly from glaciers, and adaptation measures can be adopted in such cases. While there are tangible measurements of the impact of climate change on receding glaciers, the scientific community has yet to understand better what appears to be the main impact: the impact on rainfall patterns. An ongoing parallel study being carried out by the World Bank with assistance from ESMAP,¹ will help provide more information on the impact of climate change on selected basins in Peru at mid and end century. Current, though limited, information on the impact of climate change suggest that future hydropower development in Peru should consider the following: (a) the need for continuous monitoring on the progress made in this area; and most likely (b) the need for a continuous increase in storage capacity to compensate for the loss of glaciers, more frequent Nino's climate phenomena, and a possible dryer hydrology in the south of the country.

x. **The economic analysis concludes that hydropower is an economically viable option for power expansion in Peru, when gas is valued at its economic cost.** In the sample of projects with definitive concessions, about 1,000 MW are economically viable if gas is to be valued at an economic cost of around US\$4.4 per million British Thermal Units (mmBTUs) at the power plant (for a long term scenario characterized by an average crude oil price of US\$75 per barrel). Compared to gas-based projects, the economic cost

¹ "Assessing the Impact of Climate Change on Mountain Hydrology: Development of a Methodology for a Case Study in Peru"

of hydrogeneration is about one U.S. cent per kilowatt hour (US1¢/kWh) cheaper, which would imply economic savings of around US\$50 million per year if these projects are implemented.

xi. **However, at the present considerable low price of gas (US\$2.14/mmBTU), few hydro projects would be financially competitive.** While an exceptionally good hydropower plant could be marginally competitive, if compared to the results of the latest energy auctions, only one project is being implemented by an industrial consortium (through commercial financing) as a hedge against future supply disruptions, rather than a profitable venture to supply the local market.

xii. **For long-lived, capital-intensive investments such as hydropower, longer loan tenors are vital to bring down electricity prices.** Financial energy prices show great variation by financing structure: for a typical project, the price variation between commercial finance with balance sheet financing (that is, the only option available in recent years) and one with International Financial Institution (IFI) participation is from US5.52¢/kWh to US4.11¢/kWh, respectively. Because of their longer-term loans, IFIs could have an important role in bringing down the costs of financing hydro projects (by around 25 percent), even when blended with shorter-term commercial loans.

2. Barriers to the Development of Hydropower

xiii. The study identified the presence of a set of barriers and potential factors impeding the satisfactory development of hydropower. These barriers are evidence of the lack of coherence in the current strategy to promote hydropower.

xiv. **The Camisea natural gas price for power generation, one of the cheapest in the region, introduces a price distortion that is a serious barrier to hydroelectricity and other renewable technologies.** This price is also a disincentive to the efficient use of natural gas in thermal power generation, making it uneconomical to install combined cycle units. It is understood that the Government's policy is to maintain this promotional internal price for at least the five-year period stipulated in the renegotiated contract with the producers. Instead of adjusting the gas price to create a level playing field for other technologies, the Government is embarking on a policy of incentives for renewable energy (premiums, exclusive auctions, tax incentives) to counterbalance the effect of the price distortion. These measures imply a departure from an efficiency pricing policy and cast doubts on its efficacy and sustainability.

xv. **However, the current very low price of gas is not sustainable and, most probably, gas prices will need to increase in the long run.** With further expansion of gas-based projects constrained by capacity limits of the Camisea fields and pipeline, new gas-fired plants will face the higher costs of production of new fields, as well as the economic costs of either additional pipeline capacity or, were the gas plants sited at the gas fields, the corresponding cost of additional transmission capacity to the main load centers.

xvi. **Financing capital-intensive projects, such as hydroelectric plants, is likely to be particularly difficult in the near future because global financial markets are in disarray. Interest rates and liquidity positions keep changing rapidly.** A normal situation for financing of new projects is not likely to be achieved until the toxic asset problems of major banks are resolved, and the global economy resumes economic growth, something that is not likely to occur until 2010, or perhaps later. While unusually high spot market conditions in late 2008 encouraged the expectations for hydropower development, it is unlikely that these will be maintained in the medium term or that they would be sufficient to enable financing hydro projects in current conditions.

xvii. **The regulatory system is currently in a transition period until all new regulations of Law No. 28832, the “Law to Ensure Efficient Development of Electric Power Generation,” are developed, approved, implemented, and tested.** Although the general regulations and procedures of the long-term supply auctions have already been approved, only short-term auctions have been implemented. These auctions have not succeeded in mobilizing expected electricity supply. The main reason appears to be the lack of adequate price incentives, as price caps are set at levels close to the regulated tariff. It is likely that future auctions, under the permanent regulations for long-term contracts, could confront similar difficulties if current deficiencies are not corrected.

xviii. **The current auction system for long-term contracts poses a set of constraints to hydropower that would justify separate auctions for different technologies, or even auction of large hydropower projects.** The constraints in the current auction system include the difficulty of objectively comparing the costs and risks of thermal and hydropower, a required anticipation period of three years that is inconsistent with the nature of hydropower, and the challenge of setting premiums or discounts that do not incorporate economic distortions. The current hydropower auction by ProInversión was initiated in recognition of the deficiency in the auction framework. While it is clearly an exceptional case outside of the sector’s regulatory framework that may not be required in the future, its design is considered correct.

xix. **The process of obtaining concessions and permits, subject to frequent changes engendered by legal reforms, is seen by developers as unpredictable and excessively long.** The complex nature of hydropower implies the participation of a high number of players in the process of project concessions and permits. It is perceived by most stakeholders that the lack of transparency of the process, and frequent changes engendered by legal reforms, make it unpredictable and excessively long. In particular, the legal framework regulating water rights and rights of way has major voids and constitutes a barrier for the development of hydropower projects. Also, the relatively early award of definitive concessions—which grant exclusivity rights—is proving to be an inefficient measure that often impedes the development of an attractive site (when owned by a weak developer) and hampers competition.

xx. **The weakness of the framework for environmental and social assessments threatens the prospects for a sustainable development of hydropower, especially in the eastern basins that are likely to affect indigenous people.** While environmental

assessments for power projects have been prepared since the mid-1990s, there is still a set of problems to overcome, together with the inherent conflict of interest in the Ministry of Energy and Mines' (MEM's) role as both promoter and regulator of projects. Key problems include: (i) the quality of environmental studies; (ii) weak consultation processes especially with indigenous peoples and others in local communities; and (iii) the absence of a proper framework to address social issues, including the lack of an effective benefit sharing mechanism, that properly acknowledges and respects the local communities that are directly affected.

3. Recommendations for a Coherent Strategy in Support of Hydropower

xxi. **Overcoming existing barriers will require a fresh look at the sector policies, including revisiting the role of the State as policymaker, regulator, and promoter.** The Government has stated its support for the development of renewable energy—particularly hydro and wind power—to meet its objective of ensuring an adequate supply of electricity consistent with energy security and environmental objectives. Such a strategy has the potential of making an important contribution to coping with the rapid growth of demand of electricity through the provision of a competitive and reliable source. However, the barriers outlined above are evidence of gaps in the coherence of this strategic approach.

3.1 Stronger Role of the State is Essential

xxii. **A key lesson of the reform in Latin America is that a purely market-driven expansion of generation does not resolve the extremely important issue of security of supply.** Most of the sector reforms carried out in the region, including the one in Peru, did not explicitly consider the topic of security of power supply. It was implied in the reform models that the price signals of the competitive market would provide the necessary incentives to secure an economic security level. However, experience has proven that this was not enough and that some sort of government intervention is necessary.

xxiii. **In Peru, the State needs to play a more active role to ensure adequate security of the power supply.** The proper allocation of roles between government and private agents, and understanding the complementarity between government planning and private business operations, is key for moving toward sustainable development in any infrastructure sector. If the provision of electricity planning, security of supply, and the proper functioning of an imperfect power market in a country will always be the final responsibility of the sector national authorities, the sector legal and regulatory framework should explicitly reflect this important role. This is not the case in the Peruvian legislation that established the legal framework for the energy sector.

xxiv. Given the weaknesses identified in the current system and the challenges of the external environment, the Government's role should be strengthened in the following areas: (a) sector planning and basic information, (b) pricing policy, (c) project concessions and licensing, and (d) financing of projects.

Sector Planning and Basic Information

xxv. Strengthening central planning through a better integration of power generation and transmission planning, and natural gas strategic planning, will be key to enhancing hydro development and for achieving a sustainable energy matrix.

Planning provides valuable information for the strategic design of energy auctions, especially where the promotion of hydropower is desirable. In particular, it is useful in assessing discounts and/or premiums, the energy demanded in each auction, and anticipation periods. Sector planning also provides the basis for a sound strategy for power trade agreements/regional integration, for assessing the optimal share of energy from the country's perspective, and for an economically and environmentally sound energy matrix for the country. An effort to strengthen energy planning should be tailored to the country's needs, identify clearly institutional responsibilities and allocate adequate resources.

xxvi. An important element both for sector planning and project preparation is the strengthening of the hydrometric system and the update of project inventories.

A sound design and economic assessment of a hydropower project relies heavily on the quantity and quality of basic information, particularly on hydrological data. To such end, it is necessary to have historical records of river flows, at the project site, of at least five years (ideally 10) –and maintain stations as long as possible– complemented by hydrometric data of adjacent basins and meteorological information of the region involved.

xxvii. The role of the Government in preparing projects—that is, carrying out feasibility studies—could also be considered. However, the decision to engage directly in such a demanding activity should be taken only after a thorough assessment of market conditions is completed since it would appear that, to a great extent, the private sector has the capacity and resources to assume this pre-investment risk.

xxviii. Since there is great uncertainty on the impact of climate change, the Government needs to monitor closely this area, in particular regional rainfall patterns, in order to incorporate this knowledge into the design of hydropower plants and the formulation of a power supply strategy for the country. The studies mentioned in Section 1 of this annex are important first steps in this direction

Pricing Policy

xxix. Fostering the efficiency of consumption and investment choices depends on a policy of energy prices that reflects economic costs. Excessively low gas prices threaten the sustainable development of the power sector and have motivated a set of compensatory measures that could be further distorting the incentives system. From the perspective of efficiency and environmental protection, the most desirable policy response is to price gas at its the economic value rather than at its financial cost. This could provoke the objection that a gas price increase is politically unacceptable. However, as stated above, it should be acknowledged that the current level of gas prices for power generation will not be sustainable in the future and, hence, it will be necessary to revise the current pricing policy. Whichever the impact of such adjustment on

electricity tariffs, poor consumers with low levels of consumption would experience a much smaller impact because of the Electricity Compensation Fund (Fondo de Compensación Social Eléctrica, FOSE) equalization.

xxx. **It is necessary to revise the methodology for estimating capacity payments and the conditions for such payments**, in order to yield adequate values and a correct incentive system. The current system, based on data of open cycle turbines over the past five years does not reasonably reflect the capital cost of building a new project.

Energy Auctions

xxxii. **Overcoming the constraints associated to energy auctions could be possible through three alternative courses of actions.** The current auction system poses a set of constraints that could be overcome by developing: (a) an auction system where all generating technologies compete, (b) an auction system exclusively for hydropower projects, or (c) an auction system of large hydropower projects.

xxxiii. **An auction system where all generating technologies compete for long-term energy contracts could be a viable alternative.** This is the current system under the 2006 Electricity Law,² although the incorporation of compensation mechanisms is not factored in its design. If the Government decides to proceed with auctions where all technologies compete, which implies some difficulties inherent in the comparison among technologies, some actions to consider are:

1. Setting an economically efficient discount for hydro in relation to the avoided cost of an equivalent thermal plant, calculated at the economic cost of gas. That is, the discount should constitute a mechanism to correct the distortion created by the very low price of gas.
2. Revising the anticipation periods to call for bids, requiring longer anticipation periods consistent with the nature of hydropower and other longer lead-time technologies. This is currently a main barrier for hydropower plants, since the anticipation period of three years is not consistent with typical longer lead times of hydro plants.

xxxiiii. **However, holding auctions exclusively by technology, including hydropower, is more feasible since it overcomes the inherent difficulties of comparing technology costs in an objective manner.** The adoption of a policy of separate auctions for hydro projects, where they compete in covering a specific demand (a target for hydro expansion optimized through a central planning exercise) is recommended.

xxxv. **Project-specific auctions for large hydropower projects could reduce costs considerably, especially for projects such as those being studied with the view to export to Brazil.** Such an approach would help in incorporating efficiency incentives in

² The *Ley de Concesiones Electricas Decreto Ley 25844*, and its regulations (*Decreto Supremo 009-93-EM*), were enacted in 1992 and modified in 2007. In addition, in 2006, Congress passed Law N°28832 to “Ensure the Efficient Development of Electricity Generation.” Law N°28832 is sometimes referred to as the 2006 Electricity Law.

the preparation and implementation of large projects while using price caps consistent with the economic cost of the proposed plants.

Project Concessions and Licensing

xxxv. While current legislation establishes temporary and definite concessions for hydropower, it is likely that awarding definite concessions at a more advanced stage and revising the open-ended nature of concessions would be beneficial. Important areas that merit a review of the current concession system are:

1. The need to award definitive concessions at a more advanced level of preparation or, preferably, after a competitive process for the project has been held (that is, avoiding exclusivity rights that could hamper competition and, consequently, a more efficient process); and
2. Revising the indefinite, open-ended nature of definitive concessions with a view to introduce a termination or extension under conditions to be agreed upon.

These two points are of great importance when dealing with large hydropower projects since incorporating competition into a project that has been prepared by a single group has the potential of yielding considerable economic benefits to the country.

xxxvi. Prior environmental licensing should be a requirement for a project to participate in an auction. This implies an earlier environmental clearance—prior to the award of the definitive concession—in order to reduce the uncertainty of project completion after the auction is held. Also, the role of government agencies in supporting this process should be considered since it often involves issues of their responsibility.

xxxvii. Establishing an effective benefit sharing mechanism for hydropower development could help mitigate potential environmental and social impacts. An effective benefit sharing mechanism associated to the use of water would help align the interests of affected communities and project developers and, thus, allow a smoother process, help develop local communities, and strengthen relationships among the State, the community, and the project.

xxxviii. From an environmental standpoint, it is essential to improve the environmental and social assessment for hydro development, including open and legitimate consultation processes. Specific measures are independent auditing, adequate budgeting, establishing clear and minimum requirements for the studies, proper coordination of studies in the same river basins, and working toward setting up a social agreement with the local communities affected by development. Given the fragility of the ecosystems in the Amazon basins and the vulnerability of social groups that can be affected, it is imperative to ensure the legitimacy and openness of consultation processes for these projects.

Financing of Projects

xxxix. **Explore the need and possibilities for the Government to act as a financial intermediary in mobilizing more attractive (IFI) financing and/or, in selected cases, participate in public/private associations.** Given the current financial crisis, it is likely that a normal financing of new projects would not be achieved until the toxic asset problems of major banks are resolved. Also, the mobilization of longer tenor IFI financing could considerably reduce the cost of generation expansion.

3.2 Development of the Amazon Basins for Exports to Brazil

xl. **The hydropower development of the eastern basins of the Andes constitutes one of the main challenges of the power sector in the medium to long term.** Its development offers large economic benefits stemming from the export business and from providing additional energy for the domestic market. Its satisfactory development will rely, to a great extent, on the implementation of a strategy that guarantees an adequate level of competition while protecting a fragile environment and the well-being of the populations that will be affected.

xli. **A strategy for development should include two main, and equally important, objectives:**

1. **Sustainable development based on the adoption and implementation of international standards for social and environmental safeguards that guarantee an open and legitimate consultation process; and**
2. **A competitive process aimed at maximizing economic benefits to the country.** This process should include auctions for projects prior to the award of definitive concessions. To this end, an objective technical assessment of projects, led by government agencies, is needed to break the asymmetry of information inherent in large projects.

xlii. **These main objectives should be complemented by a sound and balanced legal framework comprising an intergovernmental agreement between Peru and Brazil and concession agreements between the Peruvian state and each project developer.** Some important aspects to be included in these agreements are:

- **Intergovernmental Agreement:** (a) a statement of common objectives, economic, social, and environmental; (b) a commitment of the two countries to abide by international standards for environmental and social safeguards, including open and legitimate consultation with indigenous peoples and others in the communities affected during all phases of project preparation and implementation; (c) agreement on the principles to set a balanced share of energy between the two countries; (d) agreement on the principles for an auction/competitive process for awarding definitive concessions; (e) agreement on technical cooperation between the two countries to achieve a better and more transparent knowledge of the project and facilitate competition; (f) basic conditions for Purchase Power Agreements (PPAs); ideally, adoption of a model

contract for a build, own, operate, transfer (BOOT) arrangement with a concession expiring after 25 years; (g) principles for commercial and operational rules; and (h) that the inventory of projects should be subject to environmental and social screening carried out by the Peruvian side.

- **Concession Agreements:** (a) rights and obligations of the host country and the project developer; (b) commitment to follow international standards for environmental and social safeguards, including indigenous peoples and others in the local communities, as established in the intergovernmental agreement; (c) agreement on the role and powers of oversight groups; that is, panels of experts comprising highly skilled international experts; (d) budget to address social and environmental programs; (e) commitment of the project to effectively address unanticipated impacts, and to fund them; and (f) specifics of the tax regime

1. STUDY OBJECTIVES AND BACKGROUND

1. Given the potential of hydro generation and the fact that such potential is not being realized, the Government of Peru (GOP) formally requested the World Bank's support in developing an operational framework to mobilize investment in hydropower. Subsequently, two studies were conducted to further investigate the potential of hydropower in Peru and to propose additional mechanisms to overcome existing barriers to its development. One study, "Institutional and Financial Framework for Development of Small Hydropower" (June 2008), focused on projects of small size, that is, under 20 megawatts (MW). The second study focused on medium-to-large-scale projects. This document is a report on that study.

2. The objective of this report is to (a) support the GOP in evaluating the role of hydropower in the country's energy mix, and (b) provide recommendations for the development of an appropriate operational framework to enable public/private investment to fulfil this role.

3. The report contains the following:

- An assessment of hydropower as a strategic option for meeting future power demands in Peru. The assessment reviews hydropower's technical, economic, and financial viability (Chapters 2 through 4), and investigates the impact of alternative financing options.
- An assessment of the enabling environment for hydropower, that is, the licensing process, regulatory framework, and the proposed auctions process for power generation (Chapters 5 and 6).
- Conclusions and a set of policy recommendations for a more effective development of hydropower in Peru (Chapter 7).

4. The main government counterpart for the report is the Ministry of Energy and Mines (MEM), which formally requested assistance from the Bank to assist in mobilizing investment in hydropower. The study was done following a broad participatory process that involved multiple interviews with all relevant stakeholders (including government agencies, the sector regulator, generating companies, distribution companies, project developers, professional organizations, and other multilaterals) plus a main consultation event.

5. A workshop entitled "Framework for Hydroelectric Development in Peru" was held on October 29, 2008, to discuss initial findings and proposals on the viability of hydropower and a suitable enabling framework. The workshop allowed for a comprehensive and objective debate involving all relevant stakeholders. In addition to presentations of team members on the Peruvian case, the Brazilian and Colombian experiences were also presented and discussed. This was particularly helpful, since both countries have established an auction system for short-to-long-term energy contracts that includes hydropower projects in competition with other technologies.

1.1 Context and Sector Objectives

6. Due to the country's favorable conditions, hydropower has been, for more than a hundred years, the main source of electric energy in Peru. There is a widespread view that hydroelectric power has an important role to play in current and future power generation in Peru. Hydropower uses a clean and abundant indigenous resource that has a long history of cost-effectiveness, providing safe and reliable electricity. It also offers the most attractive option to reduce greenhouse gases, thus addressing pressing climate change objectives and the country's objective to move towards a low carbon economy. Historically, Peru's hydropower development has had relatively minor social and environmental impacts, due to its predominant run-of-river³ characteristics complemented by a few small reservoirs.

7. The power sector in Peru was unbundled in the early 1990s, followed by a privatization and concession process. The Electricity Concessions Law of 1992/93 established a modern legal and regulatory framework. Following the reform, the power shortfall was reduced, distribution losses fell drastically, and electricity tariffs were stabilized at real costs.

1.1.1 Peru's Energy Policy Objectives

8. The GOP's main sector policy objectives are guaranteeing an adequate supply of energy, that is, energy security, and diversifying its energy matrix so that it encompasses one-third of renewable, one-third of gas, and one-third of petroleum-based fuel. While hydropower has traditionally played a dominant role in electricity supply in Peru, this role has been in decline during recent years, falling from 90 percent of total electricity production in the early 1990s to 72 percent in 2007. This decline is explained by the priority given to the development of a quick and reliable market for the natural gas of the Camisea Gas Field. Consequently, the expansion in generating capacity was based mostly on gas-fueled plants, using the country's relatively large reserves of natural gas. This expansion is resulting in a high dependency on natural gas, while the hydropower potential is abundant and remains largely unused.

9. In the face of highly volatile oil prices and high opportunity costs of the natural gas used as a main source of power generation, the GOP is fully committed to promoting hydropower development in the country and has taken several measures to encourage such investment. Most recently, in May 2008, the Government promulgated a Renewable Energies decree for the promotion of renewable energy (including hydropower up to 20 MW but that could potentially be extended to cover all hydropower). Other measures recently introduced to promote hydropower include: (a) early recovery of the value-added tax (VAT) for projects with construction periods of more than four years; (b) elimination of the import duty on equipment used for

³ Run-of-the-river hydroelectricity is a type of hydroelectric generation whereby the natural flow and elevation drop of a river are used to generate electricity. Power stations of this type are built on rivers with a consistent and steady flow, either natural or through the use of a large reservoir at the head of the river that then can provide a regulated steady flow for stations down-river (Wikipedia).

hydroelectric projects; (c) measures simplifying some relevant aspects of the current licensing procedure; and (d) specific incentives for hydropower in a power generation auctions process mandated by recent legislation.

1.1.2 Barriers to Hydropower Development

10. There are several factors impeding development of hydropower in Peru:

- Lack of a comprehensive energy strategy and long-term planning that defines a role for hydro: since the reform in the 1990s, there has been no leading entity in charge of strategic thinking for the energy sector in a comprehensive and coordinated manner. The Government's strategy in the sector has focused largely on the development of the Camisea Gas Fields, which has caused a high dependency on gas-fueled plants and an increased risk of transmission congestion. This limitation is aggravated by the fact that planning is limited to transmission, without taking into account the potential benefits of power plants (hydropower or other renewable plants) located in remote regions that could help reduce congestion. Also, power plans are not well coordinated with the strategies for gas development.
- Strong incentives for gas-fueled plants that have discouraged investment in hydropower: although MEM has expressed a renewed interest in hydropower and recently granted tax incentives similar to those for gas investments, a set of measures favoring gas-fueled generation are still in place (including a moratorium on hydropower, which was only recently lifted). Other measures include: (a) the low price of gas of US\$1.4 per million British Thermal Units (mmBTU) that has been de-linked from the prices of fossil fuels; and (b) a subsidy to the transport of gas, originally justified on the grounds that the pipeline was not fully used. The lack of a level playing field for open competition among generating technologies is leading to an uneconomic power mix and a set of associated risks, such as the excessive reliance on a single pipeline for gas supply.
- Weak planning/inventory activities in hydropower: the limited allocation of both public and private resources in investigating and updating meteorological and hydrological data during the last 25 years is a significant technical constraint to hydro development. Because of its high costs and high-risk activity, it needs public sector support.
- High capital costs and limited access to long-term financing: the problem is not unique in Peru, since investors in the world tend to prefer low-risk, non-capital-intensive projects with short construction periods and rapid returns on investment. Thermal generation projects have such characteristics, whereas hydro projects, in contrast, have characteristics that make financing difficult: multiple requirements for approval at the local, regional, and national level; high capital costs; construction risks; hydrological risks; and, in certain cases, high environmental and social visibility. This situation is aggravated by the current financial crisis. Some sort of public role or private-public partnership appears to be necessary to enable access to long-term financing sources.

- Difficulties in obtaining licenses to build hydropower plants: according to project developers and sector experts, licensing procedures for hydropower are excessively taxing and complex. In addition, procedures are not always stable and more often than not, legislation tends to have gaps.

1.1.3 Power System Planning for the Next Ten Years

11. The MEM produces a 10-year plan for the power sector, the *Plan Referencial de Electricidad*, which is updated every three years.⁴ This plan is aimed at promoting power expansion through the formulation of a vision for the sector and the provision of prospective information on the power system's needs and investment opportunities. Specifically, the plan presents, in an indicative manner, the expansion needs of the country's power transmission and generation systems, and a proposal for meeting these requirements. The plan does not address financing requirements or options for a financing plan.

12. A shortcoming of the *Plan Referencial* for power is that it does not appear to be well integrated into an overall energy strategy that should also include the country's strategy for natural gas. This is particularly important because hydro and gas require major investments that need to be coordinated. Since gas and hydropower are competing and complementary power generation options, the requirements for hydro expansion are intimately related to the country's efforts in gas exploration, production, and transport.

13. The last *Plan Referencial* was prepared in 2006 for 2006–15.⁵ This plan considered for its base scenario a growth rate for peak demand and energy of 6.6 percent and 6.5 percent, respectively. To cope with this growing demand, the plan proposed a generation expansion of around 300 MW per year. However, the plan's growth expectation has been exceeded by the actual growth of the last two years, which reached an unprecedented 8.5 percent. On the other hand, actual capacity expansion has fallen short, particularly in the expansion of hydropower.

14. The *Plan Referencial* considered the commissioning of nine hydropower plants during 2010–15 for a total capacity of 1,023 MW. Only one of these plants (El Platanal, 220 MW) is currently under construction. Preparation and/or financing on the other eight projects have yet to be completed. The delays in the hydropower program, complemented by an imminent constraint in the transport of natural gas for new gas-fueled plants, pose a serious risk of power shortages in the very short term (2009–10). To mitigate the impact of such a shortage, the Government has engaged in a fast-track emergency plan for generation expansion based on short lead diesel generation units.

15. While the *Plan Referencial* is consistent with the Government's expressed commitment to promote hydropower and to achieve a rational balance between gas-fueled generation, hydropower, and other sources, the planning proposal was not

⁴ *Plan Referencial de Electricidad 2006–2015*, Ministerio de Energía y Minas, Dirección General de Electricidad.

⁵ A new plan for 2009–18 is under preparation.

accompanied by adequate price signals or a policy environment favorable for investment in renewable technologies. To address these shortcomings, the Government, in 2008, approved a set of measures to promote renewable energy. The challenge appears to be greater now, since access to financing is becoming an increasingly more serious constraint as a consequence of the global financial crisis.

1.2 New Energy World

16. In the five years ending in mid-2008, construction costs for both thermal and hydro-generating facilities have seen a relentless increase, driven by two main factors. The first is strong global demand for all types of power generation equipment, particularly in South Asia and China, where electricity demand has been growing at annual rates of 8 to 10 percent. The order books for the major global equipment suppliers were full, with the classic conditions of a seller's market.⁶

17. The second factor explaining the increase in power generation capital costs was the speculative boom in global commodity prices, accompanied in many developing countries by construction booms that also increased cement prices. Hydro project civil construction costs faced dramatic increases in steel prices (and explain the increases in construction costs for Peruvian hydro projects reported in Chapter 2 of this report). Indeed, as noted in a January 2008, report for the World Bank,⁷ there have been substantial increases in the escalation of raw materials used to manufacture equipment for power plants, including raw materials or intermediate products used to manufacture boilers, gas turbines, steam turbines, wind turbines, and motors and generators.

18. By the end of 2008, these conditions had dramatically changed as a consequence of the global economic and financial crisis. Steel rebar⁸ prices collapsed to almost one-third of their July 2008 peaks.⁹ Cement prices have fallen as demand weakened and energy prices collapsed and, in many countries, costs for proposed hydro projects are being revised downward. With the fall in global economic growth, the expectations for electricity demand growth will also fall, so order books for 2010–12 will become leaner, and prices for gas-turbine generation equipment can be expected to fall.

19. Market conditions are particularly difficult for renewable energy, as incentives for renewable energy diminish with low oil prices. Until oil (and gas) prices recover, incentives for renewable energy will diminish, making more difficult the objectives of many countries to increase the share of renewable energy. Another consequence of the

⁶We note in Chapter 6 of this report the consequences of these high, recent prices for the OSINERGMIN capacity charge calculations.

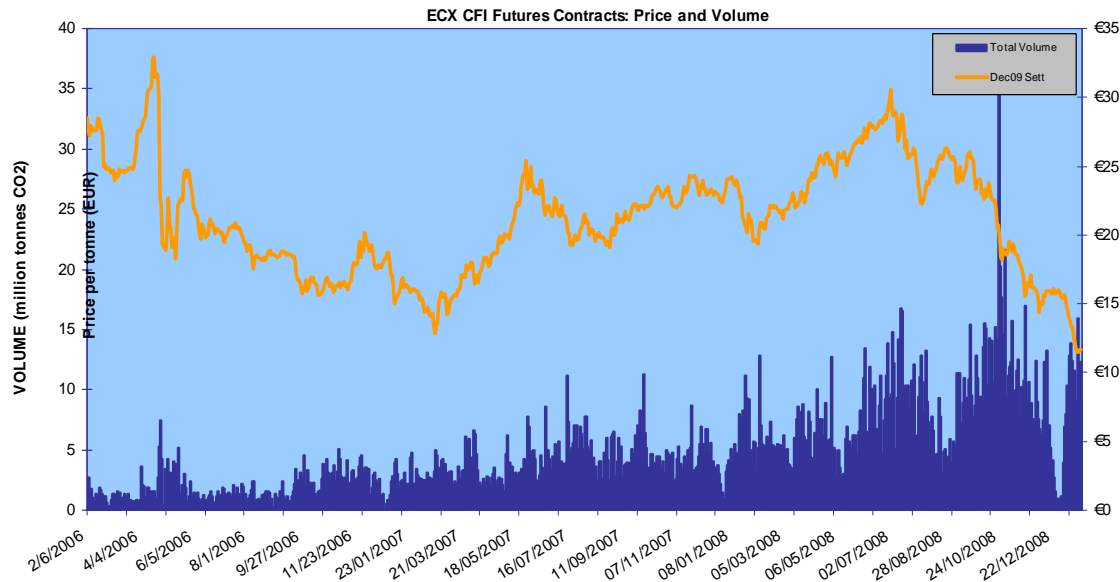
⁷URS, *Study of Equipment Prices in the Energy Sector*, Report to World Bank, April 2008.

⁸A rebar, or reinforcing bar, is commonly used in reinforced concrete and reinforced masonry structures. It is usually formed from carbon steel, and is given ridges for better mechanical anchoring into the concrete.

⁹The biggest collapse has been in billet and rebar. Since late July 2008, the London Metal Exchange cash Mediterranean billet contract has tumbled from US\$945/ton–US\$965/ton (t) to US\$554/ton–US\$555/ton at the end of September 2008. The Far East cash billet price has fallen somewhat less, from US\$870–US\$875/ton to US\$510–520/ton, over the same period. Rebar has collapsed from over US\$1,300/ton freight on board (FOB) Black Sea to around US\$650/ton–US\$800/ton FOB by the end of September 2008.

fall in economic activity is the fall in carbon prices in the European Union (Figure 1.1): since the mid-2008 peak of €30/ton, prices had fallen to €10/ton by late 2008.¹⁰

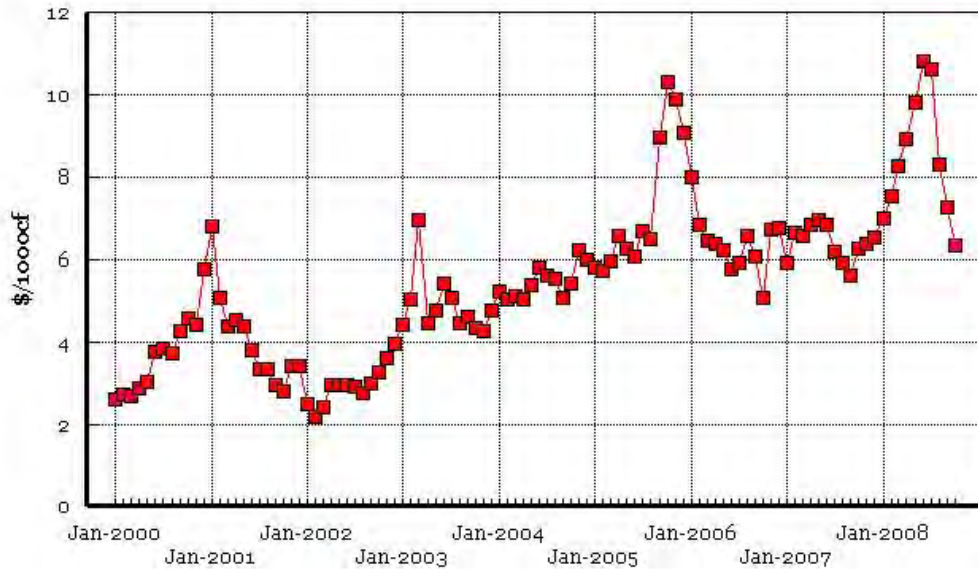
Figure 1.1: European Climate Exchange Prices



20. Given the current volatility of commodity markets, and the large uncertainties that surround the estimates of the duration and depth of the global recession, forecasting price conditions for power generation equipment in the short term—thermal and hydro—is very difficult. For the Peruvian power sector, the key question is the international gas price that governs liquefied natural gas export prices and, subsequently, the economic price of gas. As in the case of oil, prices in the latter half of 2008 dropped dramatically, from around US\$11/mmBTU to around US\$6/mmBTU (Figure 1.2), which brings it to the general price level typical of 2005–07.

¹⁰ Certified Emission Reductions (CERs) for December 2009 delivery traded on January 29, 2009, at €10.05/ton.

Figure 1.2: U.S. Gas Prices



2. TECHNICAL VIABILITY OF HYDROPOWER

21. This chapter assesses hydropower as a strategic option for meeting future power demand in Peru and improving the country's energy matrix. It is not meant to be an assessment of specific projects but, rather, of a technological option. (Chapters 3 and 4 analyze meeting future power demands from the economic and financial perspectives.) To this end, a sample of 10 projects was selected for analysis. The main criterion for selection was that projects had to have been granted a definitive concession. This criterion provided two advantages: (a) it ensured a set of tangible, realistic options, given their advanced level of preparation; and (b) the information on projects with definitive concessions is in the public domain. All the information used was made available by the Ministry of Energy and Mines General Directorate for Electricity (*Dirección General de Electricidad*, MEM/DGE). Since projects were prepared at different times, an effort was made to standardize technical and cost data to enable an accurate comparative assessment.

2.1 Technical Viability and Preparedness of Hydropower Projects in Peru

2.1.1 Hydropower Potential Development and Challenges

22. The development of Peru's hydropower resources started over a hundred years ago, at the beginning of 20th century. Initial developments took advantage of the rugged topography, which features particularly in the rivers draining the Pacific side of the Andean chain. Hydropower plants were intended to supply local electricity demands and, increasingly, the requirements of the mining industry. During the second half of the 20th century, regional power networks emerged and hydropower development began to encompass large-scale schemes. Throughout this period, hydropower contributed to a very large share of the country's power supply, usually above 80 percent.

23. Peru's hydropower development has been strongly linked to the Italian and Swiss experiences, both in its design and construction. Typically, existing plants are of the run-of-river type, including an important component of underground works, high heads, and a relatively small barrage, thus minimizing its environmental impact. Most plants have a high plant factor (that is, a high utilization of its installed capacity), which is often consolidated through the construction of small, seasonal reservoirs located in the upper basin, taking advantage of existing lagoons, favorable morphological conditions, and almost sediment-free conditions. All plants are located in narrow and steep valleys that are sparsely populated and provide few agricultural opportunities. On the western (Pacific) slope, power plants share water storage facilities with other uses, typically downstream irrigation and water supply.

24. The only comprehensive evaluation of the hydroelectric resources in Peru was an inventory undertaken in 1979 by the MEM with the support of the German Technical

Cooperation (*Deutsche Gesellschaft für Technische Zusammenarbeit, GTZ*).¹¹ The aim of this program was to identify projects that could contribute to the expansion of the country's power generation systems. The inventory focused on relatively large hydropower schemes. The final catalogue contains 543 hydropower projects nationwide representing a technical potential of 58,404 megawatts (MW) (Table 2.1). Less than 5 percent of this potential has been developed (Table 2.2).

Table 2.1: Hydropower's Theoretical and Technical Potential

Hydrological Region	Theoretical (MW)	Technical (MW)
Western/Pacific Basins	29,256	13,063
Eastern/Amazon Basins	176,287	45,341
Titicaca Basin	564	
Total	206,107	58,404

25. In areas over 1,000 meters above sea level, rivers in the Amazon and western basins show high potential for power plants with high heads, using penstocks, small intakes, and small reservoirs—a type of plant which is common in Peruvian hydropower. These projects usually have a low environmental and social impact, unless water transfers among river basins are involved.

Table 2.2: Hydropower Installed Capacity by Regions

Hydrological Region	Existing Capacity (MW)	Existing Capacity as Percentage of Technical Potential
Western/Pacific Basins	1,263	9.7
Eastern/Amazon Basins	1,563	3.4
Titicaca Basin		
Total	2,826	4.8

26. After a period where power expansion was dominated by gas-fueled power plants, there is a renewed interest in hydropower. Private and public hydropower projects that have been granted definitive or temporary concessions¹² add up to 5,796 MW; that is, around 10 percent of the resource potential (Table 2.3). The interest of developers follows historical trends, focusing more on projects in the western coastal basins that are located closer to the main load centers, and present challenging but familiar technical

¹¹ Ministerio de Energía y Minas, "Evaluación del Potencial Hidroeléctrico Nacional," 1979.

¹² As of November 2008.

features (high heads, underground structures, and limited water flows). If the projects under preparation in the western basins are built, the degree of development in this region would reach almost 25 percent of the technical potential.

Table 2.3: Current Definitive and Temporary Concessions

Hydrological Region	Definitive Concessions	Temporary Concessions	Total (MW)	Percentage
Western/Pacific Basins	1,011	895	1,906	14.6
Eastern/Amazon Basin	484	3,406	3,890	8.5
Titicaca Basin	—	—	—	—
Total	1,495	4,301	5,796	10.0

27. This ratio is smaller in the Amazon basins (12.3 percent), where projects tend to be far from consumer centers and face access difficulties. Except for two projects, this figure does not capture the recent interest in developing a set of large projects in the eastern basins, with a view to export power to neighboring Brazil. In May 2008, Peru and Brazil signed a Power Integration Agreement¹³ that constitutes a first step toward a large-scale program aimed at developing a set of export power plants located in the eastern basins. Following the agreement, 15 hydropower projects have been identified. Six of the projects appear particularly attractive for export due to their scale and distance from the Brazilian border. These projects comprise a total capacity of 6,300 MW, more than twice the current hydropower capacity of Peru, and some of them are already being studied by Brazilian public-private consortiums. Project sites were identified by the 1979 inventory and these projects are, indeed, an important part of the large hydropower potential of the country.

28. While their development can be seen as a long-term objective, it is important to stress the challenges that this ambitious program entails. Unlike the projects built or planned in the western basins, these projects are located at lower altitudes (below 1,000 meters above sea level) and, hence, encompass low heads and larger dams that may flood extensive areas. This poses serious environmental and social issues associated to the scale of the projects, the fragility of the associated ecosystems, and the vulnerability of the indigenous people and others in the local communities that would be affected. Limited hydrological information is also an important constraint. A sustainable, large-scale development of the eastern basins' potential would require a careful approach, including an improvement in the availability of basic information (particularly

¹³ “Convenio de Integración Energética entre el Ministerio de Energía y Minas de la República del Perú y el Ministerio de Minas y Energía de la República Federativa de Brasil,” signed on May 17, 2008. The agreement establishes a bilateral working group to conduct studies on export hydropower projects, including associated transmission, examining the implementation of cross-border connections, assessing the legal and regulatory frameworks of each country, and elaborating a timetable for its activities.

hydrometric), and a much-needed sound framework to address complex social and environmental issues.

29. An important dimension to consider in the preparation of hydropower projects is the impact of climate change on their effective operation and, hence, on their design and estimates of energy production and effective capacity. The impact of climate change is surrounded by a great deal of uncertainty, which stems from the difficulty in forecasting the nature, intensity, and pace of the climate change process and, in particular, its likely regional impact on rainfall patterns, mountain wetlands, and the retreat of glaciers. In assessing the impact of climate change on hydropower and other water use activities, it is important to establish the time horizon of this impact. While there is considerable uncertainty about the pace of the climate change process, the period of interest to hydropower investment decisions is clearly defined: the next 30 to 40 years, that is, the economic life of new hydropower plants. Therefore, any impact that is likely to happen after that period—regardless of its nature and gravity—is not relevant in formulating a strategy for power expansion, for specific investment decisions on new hydropower plants, or for the operation of existing plants.

30. Of utmost importance is the possible impact on rainfall patterns, since hydropower generation is directly related to the volume and seasonal distribution of rainfall. Depending on the regions and the models consulted, this impact could be either positive or negative. The Intergovernmental Panel on Climate Change (IPCC) reports¹⁴ are not conclusive in this respect. However, some specialists think there could be more rain in the north (particularly the North West) of the country while the south could be dryer, that is, a pattern similar to the El Niño phenomenon. An ESMAP-supported parallel study, being carried out by the World Bank in collaboration with the Ministry of Energy and Mines, “*Assessing the Impacts of Climate Change on Mountain Hydrology: Development of a Methodology through a Case Study in Peru*”, is investigating the impact of climate change on mountain hydrology in Peru, including the impact on rainfall. Given the current prevailing uncertainty, this report focuses mostly on a distinct and more tangible effect: the retreat of glaciers in some river basins.

31. Special attention is being given to the impact of climate change on tropical glaciers. This process is particularly important in Peru, where approximately 70 percent of the world’s tropical glaciers are located. Measurements in most glaciers in the country reveal that they have receded dramatically during the last two decades, thus reducing the natural storage capacity they provide and that some existing (and future) hydropower plants use to increase their energy production during the dry season. This report explores the nature of this impact, taking into account the information available on each project.

32. However, this effort is only preliminary and a good deal more research on the topic is needed aimed at: (a) a better understanding of the role of glaciers in the hydrological cycle, (b) the monitoring of glaciers and dry season flows of existing plants and projected hydropower plants, and (c) the assessment of options to mitigate the impact of glacier recession. Continued work in forecasting the impact of climate change on

¹⁴ IPCC, “Fourth Assessment Report,” 2007.

rainfall patterns in the region is also needed. The Hydrology Study mentioned in paragraph 30, as well as other efforts, are expected to provide new insight into these questions.

2.1.2 Technical Assessment and Review of Costs

Projects Assessed

33. There are 15 hydropower projects with definitive concessions. Five of these projects were excluded from the sample because they were either too small (capacity around 10 MW) or were already at a very advanced level of construction. The sample was therefore reduced to 10 projects that account for an installed capacity of 1,365 MW (Table 2.4).¹⁵ Capacities range from 49 MW to 255 MW, for an average of 136.5 MW, that is, a set of medium-size projects somewhat smaller than the public projects built prior to the electricity reform of the early 1990s.

34. The sample offers two main advantages for its assessment: an advanced level of preparation and easy access to project data. An effort was made to standardize data to make projects comparable in a given set of conditions (date, technical conditions). The assessment included a review of: (a) project schemes, (b) contingency requirements, (c) hydrology, (d) energy production and firm capacity, and (e) investment and operation and maintenance costs.

Table 2.4: General Characteristics of the Projects Assessed

Plant	Installed Capacity (MW)	Energy Production (GWh/year)	Head (meters)
El Platanal	220	1,079	627
Cheves I	168	837	600
Huanza	85	376	641.5
Marañón	96	425	98
La Virgen	64	388	357
Pucará	163	976	401.6
San Gabán I	150	914	567.5
Tarucani	49	362	331.7
Quitaracsa	115	639	867.5
Santa Rita	255	1,543	255
Total	1,365	7,539	

Source: Studies of each project, MEM/DGE files.

¹⁵ The study also included an assessment of three public projects that have temporary concessions. However, these were excluded from the sample due to their preliminary level of preparation.

The Assessment

35. The review did not imply any modifications to the proposed project schemes and was limited to the assessment of projects as proposed by their sponsors. Specifically, the assessment included the following:

- Review of each of the project schemes aimed at identifying specific technical and construction risks with a view to assess contingency requirements.
- Review of the projects' hydrology, taking into account updated information from the National Meteorology and Hydrology Service (*Servicio Nacional de Meteorología e Hidrología*, SENAMHI), and when pertinent, the System Economic Operation Committee (*Comité de Operación Económica del Sistema Interconectado*, COES), and/or the data provided by the studies. The hydrology review included adjustments for water regulation and water transfers when applicable.
- Estimation of energy production based on updated hydrological data, when applicable, using a single model and uniform criteria. Energy data include gross production minus losses at generators. Energy estimates were made for dry (May–December) and wet (January–April) seasons and for peak and off-peak hours.
- Estimation of transmission losses from the power plant to its delivery to the National Grid (*Sistema de Interconectado Nacional*, SEIN); that is, the losses of the transmission system associated to the project. These losses were estimated at 1 to 3 percent of energy production, depending on the length of the associated transmission system.
- Estimation of firm capacity and remunerable capacity based on dry season flows and the daily regulation capacity of each plant.
- Review of the impact of climate change on energy production, in particular, the impact of the ongoing melting of glaciers. Recognizing that this is a very complex issue that requires further research and analysis, a preliminary assessment was made in order to arrive at an order of magnitude result and set the parameters for an economic sensitivity analysis.
- Review of investment costs. Investment requirements in projects were updated as of early 2008, considering market values for equipment and civil works. To this end, the analysis included the review of most recent bids and construction costs (when projects were already at that stage), updating values to the said date, and the application of updated unit prices and parametric curves (for projects at a less-advanced level of study). Contingency costs were added as a function of the projects' level of study and complexity of design. These costs ranged from 5 percent to 15 percent.
- Investment costs include the associated transmission systems of each project, that is, the cost of the transmission facilities needed to connect to the SEIN. Costs of SEIN reinforcements are not included.

- Maintenance and operation expenses are calculated at US\$0.0025 per kilowatt-hour (kWh) produced,¹⁶ and annual insurance and administrative payments, estimated as installed US\$5/kWh. In addition, payments to the system (COES), to the Ministry of Agriculture, and to the MEM are also taken into account as representing 1.5 percent of annual sales.
- With the exception of those projects with a more advanced level of preparation (or construction), a standard construction schedule was used to estimate disbursement flows.

The assessment of hydrology and energy production yielded the following results;

- A set of adjusted energy production figures that differed from the values proposed in studies by +3 percent to -28 percent.
- The average deviation/adjustment was -6.8 percent (weighted average: -9.2 percent), that is, an average below the estimates of project sponsors.

The assessment of project capital costs yielded the following results:

- An increase in cost estimates ranging from 18 to 86 percent;¹⁷
- An average increase of 44.8 percent (weighted average: 39.1 percent);
- The adjusted capital costs correspond to unit costs of installation ranging from US\$1,164 per kilowatt (kW) to US\$1,939/kW, for an average of US\$1,450/kW.
- The increasing trend is explained by several factors, the main being the update of U.S. dollar values to a more recent date and the sharp increase of civil works costs and equipment prices experienced during the high growth months prior to the study. Another factor appears to be an overly optimistic approach to design or cost estimation for some projects.

36. It was found that all projects follow the Peruvian hydropower experience; that is, they are run-of-river projects including a relatively small dam or barrage, followed by canals or tunnels to gain head, and a powerhouse a few kilometers away. There are no powerhouses at the foot of the dam.

37. While no general judgments can be made on the whole sample, the following was observed:

- Some projects are very well studied. They have thorough field research programs and sound engineering and technical schemes. In such cases, no construction difficulties are foreseen.

¹⁶ Assuming a minimum value of US\$1 million per year.

¹⁷ These figures exclude a project that, due to a drastic change in its components, experienced a capital cost reduction of -65 percent.

- Other projects appear to be too optimistic in their design or have yet to solve specific construction problems. However, in most cases these issues can be solved if adequate engineering and field research resources are used.
- While the lack of an adequate hydrometric network in the country is a problem shared by all projects (see section 2.4 on hydrometeorological information), it was found that, generally speaking, projects are being designed in a satisfactory manner in regions where information is available, complemented by the investigations of each study. However, some projects show inaccurate hydrological estimates, while others are closely linked to the construction of reservoirs with agricultural irrigation.
- Many projects have used hydrologic data collected by their own stations. Several of the rivers present a risk of sedimentation in certain parts of their basin, which has not been fully taken into account by the projects. Furthermore, none of the assessed projects seemed to take into account the impact of rapid glacier retreat.
- The energy production of some projects tends to be high due to their reliance on relatively large seasonal reservoirs.
- Many of the projects holding a definitive concession have been owned by developers whose main concern has been preparing and selling them, rather than building them. During 2007, three definitive concessions were sold to groups associated to large consumers: Huanza, Marañón, and Quitaracsa.

Project Design

38. The availability of the basic field information required for project design is generally good:

- Electronic versions of topographic maps at 1:100,000 scale are immediately available from the National Geographic Institute (*Instituto Geográfico Nacional*, IGN) and electronic maps at smaller scale (that is, 1:25,000, prepared for the Ministry of Agriculture) can be obtained from the IGN on request.
- Similarly, 1:100,000 scale geological maps and several smaller-scale regional and local maps are available from the Geologic Mining and Metallurgic Institute (*Instituto Geológico Minero y Metalúrgico*, INGEMMET).
- Hydrometeorological data are available from the National Meteorology and Hydrology Service (*Servicio Nacional de Meteorología e Hidrología*, SENAMHI), but it is evident the capacity of this organization has been deteriorating over the past decade.

39. Parallel to collecting and analyzing basic field information as described above, local topographic, geological, and hydrometric investigations at the project site must be carried out. There is sufficient local capacity in all these areas, with a number of firms offering up-to-date services in competitive bidding.

40. Suitable expertise is available at most levels (with a number of national and international consulting engineering companies), although it could be argued that, as a result of the limited number of larger-scale water resources schemes designed and

constructed in recent years, there are only a limited number of people with the comprehensive and long-term experience required for successful overall project management.

41. The MEM maintains a list of 125 consulting companies authorized to execute environmental impact analyses, of which 74 are authorized to work in the electricity sector. This list includes mostly national consulting engineering companies, together with the local offices of many international consulting firms. There are also a number of locally based companies offering services relating to the Clean Development Mechanism (CDM) and the acquisition of carbon credits, and international companies such as Eco Securities, Net Source, AHL Carbon, and Econergy.

Project Engineering

42. As for project design, there is also sufficient national expertise and experience among the consulting engineering companies to carry out all the services required in the preparation of contract documents for construction and the supervision of contractors and suppliers during construction. This expertise and experience covers the more traditional client-consultant-contractor form of project arrangement, and the engineering procurement, and construction (EPC) type of contract.

43. However, the use of standard contract documents, such as those produced by the International Federation of Consulting Engineers (FIDIC), is not a common practice. It would appear that in most cases specifications and contract documents are prepared from scratch or at least on the basis of other previous similar projects. Although their use would benefit the sector, it may be noted that previous attempts to use the Spanish language versions of FIDIC contract documents in Peru have highlighted some differences of interpretation of certain words in the context of Peruvian law.

2.2 Climate Change Considerations

44. There is great uncertainty about the likely impact of climate change on the Peruvian weather patterns and its hydrological cycle (see Annex 1 for more on this issue). While there are tangible measurements of this impact on receding glaciers, the scientific community has yet to adequately understand what would be the main impact: that is, the impact on rainfall patterns. IPCC reports are not conclusive in this respect. As mentioned, there is the view among some specialists that there could be more rain in the north (particularly the North West) of Peru while the south would be dryer, that is, an impact similar to that of a major El Niño that occurs once every 7 to 10 years. Changes in rainfall patterns would have an impact on both energy production and the nature of extreme events (floods) and, thus, in the design of hydraulic structures of hydropower plants.

45. A parallel World Bank initiative, with ESMAP support and in collaboration with the Ministry of Energy and Mines, aims to demonstrate a methodology to assess the

impacts caused by climate impacts (rapid mountain warming, with the consequent changes in glaciers and mountain wetlands, and change in rainfall patterns) on Peru's hydrology. The study is titled "Assessing the Impacts of Climate Change on Mountain Hydrology—Development of a Methodology through a Case Study in Peru". This parallel study is expected to provide additional information for hydropower planning in Peru in the longterm through the following components:

- a. Climate: Use of outputs from the Earth Simulator¹⁸ and the Community Climate System Model, CCSM¹⁹, for a selected scenario to assess net impacts in precipitation and temperature over the watersheds in the Andes of Peru. The objective is to provide likely scenarios of future climate for mid and end of century in Peru, capable of producing environmental parameters to be used as inputs for hydrology modeling.
- b. Hydrology: Estimate of current and projected changes in runoffs caused by increases in temperature, glacier retreat, changes in precipitation and drying of mountain wetlands for three emblematic basins in Peru: Rio Santa, Rimac and Mantaro river basins, to 2030, 2050 and 2090. The modeling technique to be used is WEAP (Water Evaluation and Planning Tool) developed by the Stockholm Environmental Institute combined with a simulation module of the dynamic behavior of glaciers jointly developed by IRD and SEI.

46. A third activity being implemented by the World Bank that is expected to provide more information on climate change impacts on hydrology in Peru is the "Regional Andes: Implementation of Adaptation Options to Rapid Glacier Retreat in the Tropical Andes Project."

47. Given the uncertainties surrounding the impact of climate change on rainfall patterns, the remainder of this section focuses on the process of retreating glaciers. Measurements in most glaciers in the country reveal that glaciers have receded dramatically during the last two decades, thus reducing the natural storage capacity they provide and that some hydropower plants use to increase their energy production during the dry season. Subject to the yet limited knowledge on the role of glaciers as natural storage, and the incipient research in these matters, the team explored the nature of the problem in order to have a better understanding of its impact on current and future hydropower generation in Peru. Preliminary conclusions are as follows:

¹⁸ The Earth Simulator is a super computer. The code for the model run by the Earth Simulator was developed jointly by the Center for Climate System Research (CCSR) of the University of Tokyo and the Japanese National Institute for Environmental Sciences (NIES). The particular version of the CCSR/NIES AGCM has been used for several international modeling efforts, including future projections for the Intergovernmental Panel for Climate Change (IPCC, SRES) and the Atmospheric Model Intercomparison Project (AMIP).

¹⁹ The CCSM-2 released in 2002 simulates climate by dividing the world's water and land surface into rectangular grid points that extent upward into the atmosphere in 26 vertical layers. Its resolution varies from 2.8 degrees for oceans and sea ice, to 1 degree which corresponds to approximately 100km resolution. www.ucar.edu/communications/CCSM/index.html

- The gradual loss of glaciers will have a considerable impact on those plants or projects where glaciers have a dominant role in the hydrological cycle. The problem is irrelevant when there are no glaciers in the watershed and less relevant when they play a minor role, say, less than 5 percent of the watershed area.
- Only 2 of the 10 projects assessed in the sample have a glacier area that exceeds 5 percent of the watershed. Also, only 307 MW (Cañon del Pato – 264 MW and Cahua – 43 MW) of the existing 2,826 MW of hydro capacity installed in Peru, that is, around 11 percent, feed from watersheds where glaciers provide a significant contribution. Other plants, such as Huinco (258 MW) and Callahuanca (85 MW), used to feed from glaciers that have already been lost (or almost lost). Also, in a few cases, the lost storage capacity of glaciers has been replaced by small reservoirs located in the upper basin (for example, Santa Eulalia basin).
- The impact would be limited to the dry season, since all hydropower plants—existing and planned—have or will have an excess of water during the rainy season. Also, this impact would be mostly on the production of energy, and not on the capacity guaranteed by the hydro plant, since most plants have, or are designed with, daily regulating facilities that would usually allow them to continue operating at the peaks during the dry season, even under conditions of reduced water flows, thus reducing the economic impact. In fact, since the revenues of a hydropower plant stem from: (a) the energy it sells, and (b) the effective capacity it offers to the system, a typical plant would be affected only in its dry season energy sales. From this point of view, it could be argued that other uses, such as urban water supply or irrigation, would be more vulnerable to the impact of the loss of glaciers.
- The main area affected by the melting of glaciers would be the Santa River basin, which feeds from the Cordillera Blanca, the largest mountain range in the country and a touristic region known for its scenic beauty and outdoor recreation activities. There is evidence that some tributaries of this river basin are already showing the impact of the glacier melting process, reducing its runoff during the dry season by as much as 20 to 25 percent.²⁰
- However, a review of the hydrology of 40 years for the 10 projects assessed in this study does not show a clear trend in terms of changes in river flows. Two projects reveal a statistically significant reduction in dry season flows (Quitaracsa and Santa Rita, both in the Santa River basin) while one project reveals an increase in these flows (Huanza, in the Santa Eulalia River basin).
- Project developers are planning mitigating measures to counterbalance this impact when relevant. The main solution being considered is the gradual construction of small, high-altitude reservoirs to compensate for the lost storage capacity. These small dams will also benefit other users downstream—for example, water supply and irrigation. Some developers propose that, since this is a multisector issue, the

²⁰ At the Quitaracsa River, a case where apparently low-altitude glaciers have already been lost, the potential energy production during the dry season (May–December) would have been reduced by around 21 percent during the last six years. This value is used as a reference for the sensitivity analysis presented in the economic chapter of this report.

state should intervene in its planning and, when warranted, in sharing investment costs.

- In most glacier basins, it is common to find favorable morphological conditions for the construction of small dams, since the recession of glaciers has left relatively narrow river sections where moraines²¹ are already acting as natural dams (in many cases there are lagoons).
- Preliminary cost estimates suggest that the additional investment in small dams to compensate the foregone storage provided by glaciers would increase the average energy production cost of a hydropower plant by around 3 to 4 percent.²²

48. In summary, the recession of glaciers is an event that warrants further research, particularly in understanding the contribution of glaciers as natural reservoirs and the nature of the ongoing melting process. Its impact on hydropower is limited to the existing and future sites where glaciers play a significant role in the basins' hydrology. When relevant, preliminary estimates suggest that this impact could be an energy loss of about 20 percent during the dry season. Two main adaptation measures have been identified: (a) the construction of small dams in the upper basins aimed at restoring the natural storage lost; and (b) compensating energy losses through energy purchases in the spot market, most likely energy of thermal origin. While the first measure would benefit all water users located downstream, the latter measure would be a solution exclusive to the power sector.

49. Overall, current though limited information on the impact of the different aspects of climate change (impact in rainfall patterns, glaciers retreat, etc) suggest that future hydropower development in Peru should consider the following: (a) the need to monitor continuously the progress made in this area; (b) the need of a continuous increase in storage capacity to compensate for the loss of glaciers, more frequent Nino's and a possible dryer hydrology in the south of the country; and (c) a strategic approach to hydropower development taking into account the likely regional differences of the climate change impact.

2.3 Social and Environmental Issues

50. Peruvian legislation mandates the preparation of an Environmental Impact Study (*Estudio de Impacto Ambiental*, EIS) for all power plants with an installed capacity above 20 MW. The EIS should be approved by the MEM/General Directorate for Energy

²¹ A moraine is an accumulation of earth and stones carried and deposited by a glacier.

²² For a project that would be losing around 20 percent of its energy during the dry season. It is estimated that the capital costs of high-altitude dams in favorable sites could range from US\$1 million to US\$5 million, for reservoirs in the range of 5 to 20 million cubic meters. In the case of the Quitaracsá tributary, restoring the eventual loss of 2 cubic meters per second during the dry season (equivalent to 16 to 17 gigawatt-hours [GWh]) would require an additional storage of around 35 million cubic meters, which would cost around US\$8 million. This would yield a cost of US4.9¢/kWh for the energy recovered. This figure should be compared to the cost of the alternative solution: buying energy from the spot market. As a reference, the production cost of a gas-fueled combined cycle plant would be US5.3¢/kWh (for a power plant operating at a plant factor of 75 percent and an oil price of US\$75 per barrel).

Environmental Matters (*Dirección General de Asuntos Ambientales Energéticos*, DGAAE), and has to identify and evaluate all possible direct and indirect environmental impacts, including biological, physical, cultural, and socioeconomic. Also, it should include an Environmental Management Plan (*Plan de Manejo Ambiental*, PMA), which should aim at minimizing, avoiding, and/or compensating those negative effects, including measures designed to protect local communities. Social impacts associated to power plants are addressed through the EIS process since there are no separate procedures to deal with social issues. The EIS practice started in the mid-1990s and, since then, the country has been gradually building a capacity to deal with this requirement.

51. The team reviewed the environment files of the MEM of all projects with definite concessions. The most common impacts found were as follows:

- Changes in river flows due to water diversions at the project area and/or the operation of a dam;
- Pollution during the construction phase (soil, water and air quality, and noise);
- Impact on aquatic fauna due to changes in flow patterns;
- Displacement of wild species;
- Resettlement of communities and native population;
- Impact on green areas;
- Impact on employment in the project area.

52. While it is generally believed that the typical Peruvian high head, run-of-river hydropower plants are low-impact projects, this is not always the case. There are a set of technical and institutional issues of concern that merit more attention in order to ensure sustainable hydropower development in the country. The review of the EIS found weaknesses on both substance and process issues. These include:

- The team's experience was that the access to information is difficult. Project files are not standardized, tend to be disorganized, and are often incomplete. This hinders the monitoring capacity of the public agencies and the consultation/public dissemination process.
- The very diverse quality of EISs indicates that the operative terms of reference do not set standard minimum requirements for the studies.
- The assessment of social impacts, especially with respect to local communities, is usually very weak. It tends to be limited to a vague and general description. Often, affected populations are not properly identified or quantified, and current and future livelihood systems are not well assessed.
- Although there are guidelines to guarantee the participation of affected communities,²³ it is alleged that this is rarely done in a satisfactory manner.
- Common technical shortcomings of the EISs are: (a) environmental baselines loosely linked to the specific impact of the project, and no delimitation of areas of influence; (b) lack of adequate maps; (c) no interdisciplinary and integrated

²³ Reglamento de Participación Ciudadana para la Realización de Actividades Energéticas, R.M 535-2004-MEM-DM.

- analysis; (d) weak analysis on biological impacts; (e) absence of rescue programs for cultural values; (f) flawed approaches to the estimation of ecological flows, resulting in very low values; and (g) underestimation of resources needed for adequate mitigation plans.
- The capacity of MEM to supervise and assess the studies and monitor follow-up activities is hampered by staff and budgetary resource constraints.

53. It can be argued that, given the relatively benign nature of most of the projects being prepared, the existing shortcomings do not pose a serious constraint to the development of hydropower in Peru. However, there have been events of social unrest associated with some of these projects in recent months, thus suggesting that the EIS process is not rendering the desired results. Recommendations to improve this process are presented in Chapter 5 (para. 204).

54. The Government's interest in a larger-scale development of hydropower—such as the development of a set of large projects in the eastern/Amazon River basins with a view to exporting electricity to Brazil—makes it imperative to strengthen the quality of environmental studies, and its consultation and monitoring and approval processes, to ensure an adequate and sustainable balance among the country's economic, social, and environmental protection objectives. The experience of the Nam Theun 2 Hydroelectric Project, a 1,200 MW plant being built in the Lao People's Democratic Republic (PDR), could be a useful reference for sound management of a highly complex hydropower export project, including a set of innovative measures to manage a variety of project risks (see Box 2.1).

55. In particular, the preparation and development of large hydropower projects in the eastern slope, for export or the domestic market, should take into account the following:

- The scale and complexity of its social and environmental impacts and the current weaknesses of the country in addressing them.
- The projects of interest are being drawn from the old hydroelectric inventory prepared in 1979—that is, a study that was carried out following the practice of the late 1970s and, accordingly, is very weak in its assessment of social and environmental issues. It would be useful for MEM to undertake a screening exercise with the view of eliminating, at an early stage, those projects that, due to the complexity and scale of their social and environmental impacts, are not acceptable according to today's standards.
- An explicit commitment of the countries involved in developing the projects according to sound and proven international standards for environmental and social safeguards, including those related to indigenous peoples and local communities. Such agreement should be incorporated into a formal power trade intergovernmental agreement to be signed by the countries concerned, and into the concession agreements between the GOP and each project developer. The standards should address the following issues: environmental assessments, natural habitats, forests protection, cultural heritage, indigenous peoples, involuntary

resettlement, safety of dams, and issues associated to the use of international waters.

- An adequate monitoring and evaluation framework for the preparation, construction, and operation of each of the projects. This framework should include internal and external/independent bodies. The participation of panels of experts comprising specialists of international reputation should be essential in addressing complex social and environmental issues, as well as dam safety and other engineering matters, in a thorough and objective manner. Ideally, the role (and powers) of these oversight groups should be established in the concession agreements and the intergovernmental agreement.
- A continuous and open stakeholder consultation, tailored to the social and institutional needs of each project, should be carried on throughout the life of the projects. Such a consultation process would be essential for the sound evaluation of social and environmental impacts, the design of environmental management, mitigation and resettlement plans, and in designing and implementing grievance mechanisms.
- Provision of an adequate budget to cover all environmental and social mitigation costs that are reasonably foreseeable, including an agreement (incorporated into the concession agreement of each project) to fund, from the project proceeds, environmental management programs associated to the river basin, including watershed protection programs.
- Concession agreements should also provide for financial mechanisms to address unanticipated project impacts, establishing the obligations of the project developer to secure such mechanisms (for example, bonds, letters of credit).
- A sound institutional framework on the government and project developer sides, to address all project management issues.
- A plan to strengthen the hydrometric network of the country, designed and implemented in coordination with the different projects, considering that the network is weaker in the eastern river basins.

2.4 Hydrometeorological Information

56. A sound design and economic assessment of a hydropower project relies heavily on the quantity and quality of basic information, particularly on hydrological data. Otherwise, the amount of energy that a project offers cannot be estimated with an adequate degree of certainty, nor can the risks (technical and economic) be estimated, and would be unacceptable. Also, sound project design and construction arrangements require adequate information on extreme events, that is, floods and rainfall. To that end, it is desirable to have historical records of river flows, at the project site, of at least five years (ideally 10) –and maintain stations and continuous records as long as possible– complemented by hydrometric data of adjacent basins and meteorological information on the region involved.

57. An important finding of the World Bank report on small hydropower in Peru²⁴ was that there is a need to strengthen the country's hydrometeorological network and SENAMHI's service in providing such information. During the last 25 years, the network has suffered a drastic reduction in its size and quality, declining from around 2,000 hydrometeorological stations in the early 1980s, to the 780 stations under current operation by SENAMHI (of which only 176 measure river flows). The main reasons for this reduction are the pressures exerted by terrorism, natural disasters (floods, and so forth), and budget constraints.

58. Another principal aspect of the hydrometeorological data problem in Peru today is the increasing fragmentation of data collection activities, in particular since deregulation of the electricity sector. Many more hydrometeorological stations are being installed and operated by private power companies, mining companies, and developers, in addition to those operated by other government agencies.²⁵ According to the law, permission to install and operate such stations should be obtained from the Government and, also, the information obtained should be made available to the Government. However, in practice, this is rarely done. A central repository of all hydrometeorological data would be of considerable assistance to the designer of a hydropower project.

59. Because of budget limitations on manpower and on hardware and software for acquiring and processing field data, obtaining and using data from SENAMHI usually reveals a number of shortcomings including: excessive time required to obtain data, unavailability of recent observations, and absence of information on how data were obtained (in the case of flow data, for instance, the number and frequency of measurements carried out in order to derive rating curves and the range of water levels and discharge covered), which would otherwise enable a judgment to be made on the reliability and precision of the data.

60. While the lack of an adequate hydrometric network is a problem that affects the whole country, projects are being designed in a satisfactory manner in regions where information is available, complemented by the data obtained through stations installed by project developers at their own cost. The situation is more critical in the eastern basin, where there are plans for large-scale developments and the information is extremely limited. It is reported that Electroperu installed a set of stations in this area during the early 1980s, but these were deactivated after a few years of operation. Given the size of the planned investments, about US\$10 billion or more, the risks associated to a weak availability of basic information are huge.

61. Hydropower developers (and the national power system operator COES) form only one group of users of hydrometeorological data. Other groups that use such data

²⁴ "Peru – Institutional and Financial Framework for Development of Small Hydropower," World Bank, forthcoming (b).

²⁵ In addition, other national and local state agencies such as the Natural Institute for Natural Resources (*Instituto Nacional de Recursos Naturales*, INRENA), the National Institute for Development (*Instituto Nacional de Desarrollo*, INADE), and the Ministry of Agriculture's regional offices and other entities within the latter continue to operate stations and compile data that are not stored in any central facility.

include organizations involved in (a) irrigation and other forms of agriculture, (b) potable and industrial water supply for municipalities and rural areas, (c) wastewater disposal and environmental pollution, (d) mining operations, and (e) environmental protection and nature conservation.

62. Within the context of the continuing economic growth of the nation, it may be considered, therefore, that the time is now appropriate for a radical overhaul of the situation with regard to the measurement, acquisition, and dissemination of hydrometeorological information.

63. Such an overhaul would involve:

- An assessment of the challenges and needs, taking into account the requirements of large-scale development of hydropower in the country and all other water users.
- Significant revision of the responsibilities of SENAMHI as a central depository of data, and possibly other government agencies. In this connection, the World Bank-supported Hydrology Project in India²⁶ could serve as an example of how a Hydrological Information System for use by all potential users concerned with water resources planning and management, both public and private, can be established and sustainably operated.
- Changes to the laws (or to implementation of current laws) regarding ownership of hydrometeorological observations by private organizations, with a view to ensure that data are made available to the public once they are no longer considered confidential.

64. Technical recommendations to strengthen the hydrometeorological network are presented in Annex 2.

2.5 Conclusions of the Technical Assessment

65. The technical assessment of the sample of projects suggests that there are a considerable number of hydropower projects with definitive concessions that are technically sound and could start construction shortly. The preparation of these projects has been possible through the availability of good basic information and capable national expertise. Most projects being prepared are of the run-of-river type, following the traditional Peruvian technology, that is, medium-size plants with high heads, underground structures, and small barrages that often tend to have a limited environmental impact. From a technical point of view, these projects, which could add more than 1,000 MW, could be commissioned by or around 2012–14. These projects, plus others of similar characteristics that are at an earlier stage of preparation, constitute one of the main options available to the country for developing a low carbon economy. There is also a set of hydropower projects with temporary concessions (adding an additional 4,300 MW), which, if proven to be technically and economically sound, could

²⁶ “Hydrology Project Phase II,” Project Appraisal Document (PAD No. 28140-IN) on a proposed loan to the Government of India, World Bank, 19 July 2004.

make an important contribution to meeting the country's power demand from 2015 onward.

66. The eventual development of larger projects in the eastern Amazon basin poses an unprecedented environmental and social challenge associated to their scale, the fragility of ecosystems, and the vulnerability of the people that would be affected. Limited hydrological information is a constraint, as is a weak institutional setting. Sustainable large-scale development of the eastern basins' potential will require a careful approach that should include an improvement in the availability of basic information, and a stronger framework to address complex social and environmental issues and guarantee an open and legitimate consultation process. Failure to do so could have catastrophic effects and impede the development of this valuable resource. Peru could benefit from the experience of other countries (for example, the Nam Theun 2 project in Lao PDR) in managing the risks stemming from large hydropower in a thorough and transparent manner.

67. There is great uncertainty about the likely impact of climate change on Peruvian weather patterns and its hydrological cycle. While there are tangible measurements of this impact on receding glaciers, the scientific community has yet to adequately understand what appears to be the main impact—the impact on rainfall patterns. Also, the period of interest to investment decisions in hydropower (which is limited to 30 to 40 years, that is, the economic life of a new project) could differ from the longer-term horizon of the climate-change process. The recession of glaciers is an event that warrants further research to better understand the contribution of glaciers as natural reservoirs and the nature of the ongoing melting process. A preliminary assessment of its impact on hydropower production suggests that this could be limited, given the reduced number of projects that feed considerably from glaciers. Two main adaptation measures have been identified: (a) the construction of small dams in the upper basins aimed at restoring the natural storage lost; and (b) compensating energy losses through energy purchases in the spot market, most likely energy of thermal origin.

68. The Government's interests in a larger-scale development of hydropower makes it imperative to strengthen the quality of Environmental Impact Studies and the consultation and licensing processes, in order to ensure an adequate balance among the country's economic, social, and environmental protection objectives.

69. Given the potential of hydropower generation in the country, the interests of public and private shareholders in developing this potential to cope with the power demand of a fast-growing economy, and the lack of an adequate hydrometric network, it is essential to proceed with a radical overhaul of this network. This effort should include measures associated with the measurement, acquisition, and dissemination of hydrometeorological information.

**Box 2.1: The Nam Theun 2 Hydroelectric Project in Lao PDR:
Lessons from a New Business Approach**

Background. Lao People’s Democratic Republic (PDR) is a small, landlocked country situated in the center of the dynamic Mekong region. To overcome poverty, Lao PDR needs to grow, and the Government of Lao (GOL) has embarked on a poverty reduction strategy. The US\$1.45 billion Nam Theun 2 Project (NT2) complements this effort. It reinforces the GOL’s reform program and helps maintain a development path by raising revenues through environmentally and socially sustainable hydroelectric exports to Thailand that will be applied to finance poverty reduction interventions.

The Bank adopted a new business approach to NT2. The goal was not only getting this large, complex project ready for the country, but getting the country ready for the project. Therefore, its preparation included a broad risk identification and mitigation strategy. The project’s technical features were strengthened, all 10 World Bank safeguard policies were addressed, and consultations and communications were upgraded to meet the demands of a challenging environment. NT2 preparation focused on a Decision Framework, which was founded on the following three pillars:

1. The GOL implementing a development strategy and program characterized by concrete performance on poverty reduction and environmental protection;
2. The project developer and GOL ensuring that the project’s technical and economic aspects and the implementation of safeguard policies complied with internationally acceptable standards; and
3. The GOL obtaining broad support from international donors and civil society.

As the new business approach was launched, oversight groups were stepped up. External, independent expert oversight groups, including the International Advisory Group, which reported to the Bank’s President; the Environmental and Social Panel of Experts; and the Dam Safety Review Panel advising the GOL, played active roles.

World Bank Group support to NT2 consists of the following three components:

1. A hydropower facility with installed capacity of 1,070 megawatts (MW), providing power for export to Thailand, and an additional 75 MW for domestic use;
2. Management of the project’s environmental and social impacts on the Nakai Plateau, in watershed and downstream areas of the Nam Theun and Xe Bang Fai Rivers; and
3. Monitoring and evaluation arrangements designed to meet, in a timely manner, sound engineering practices, fiduciary responsibilities, and the oversight requirements of the financial institutions.

NT2 project preparation led to several desirable outcomes, including:

- Strengthening management of the environmental and social impacts (all 10 Bank safeguard policies were triggered by NT2), an aspect that has plagued many hydro projects, through enhanced design features relating to risk mitigation, financing, participation, and monitoring and evaluation;
- Fashioning constructive engagement among government, regional partners, local populations, and other key stakeholders, including the private sector and civil society, by building ownership, quality, participation, and consensus, and achieving a high degree of transparency and disclosure; and
- Formulating an acceptable way in which natural resources rents could be extracted and applied transparently to poverty reduction, thereby avoiding the “natural resource curse.”

The new business approach has triggered fundamental changes in Lao PDR. Local populations now have a voice in designing projects and Lao officials are now well positioned to negotiate other deals, including several new regional hydropower projects. The NT2 experience has made the country more competitive, more attractive for investors, and more transparent.

3. ECONOMIC RATIONALE OF HYDROPOWER DEVELOPMENT: ECONOMIC ANALYSIS

70. As part of the evaluation of the potential future role of hydropower in Peru, it is essential to demonstrate that hydropower is one of the least-costly options for power generation, on an economic basis. This chapter will do that by carrying out a cost-benefit analysis of the same set of projects that were analyzed from the technical viewpoint in Chapter 2. The cost-benefit analysis will be done from the perspective of the country as a whole, without considering financing options and taxes. (Chapter 4 presents an analysis of the role of hydropower from a financial point of view, including financing options.)

71. In analyzing the economic viability of hydropower, it is essential to take into account the distortions introduced by the current very low price of natural gas for domestic use, including power generation. The price for natural gas, one of the lowest in the world, was introduced by the Government of Peru to promote the use of newly available natural gas after the development of the Camisea Gas Field in Peru. Its low price has made natural gas the preferred fuel for power generation over the last 10 years. However, in carrying out an economic analysis of hydropower generation, it will be necessary to recognize the economic value of gas.

3.1 Methodology

72. The economic analysis of hydro projects is based on the estimates of capital costs developed in the technical evaluation of projects, estimates of operating costs, and the proposition that the benefits are defined by the avoided costs of gas-fired generation. The presumption is that in the absence of the hydro project, the equivalent energy and capacity would be provided by a mix of open cycle and combined cycle gas-fired projects.

73. Currently, the mix of open and combined cycle projects in Peru is distorted because of the very low gas price, which results in a much greater proportion of open cycle projects than would be the case at more realistic gas prices. The low gas price also results in a wasteful use of natural gas because of the low efficiency of open cycle combustion turbines (OCCT) and the foregone additional capacity that could be achieved by closing the thermal cycle through combined cycle gas turbines (CCGT).

74. In a well-designed thermal system, OCCTs would run for no more than two to four hours a day, with the balance provided by CCGTs. The combination of OCCT and CCGT capacities, equivalent to the firm capacity of the hydro project, can be derived, and is used to calculate the equivalent avoided capacity benefit (the weighted average capacity cost), and the equivalent avoided energy benefit (weighted average variable cost of generation), of a hydropower project. Assumptions for an avoided cost computation for a typical hydropower plant are presented in Annex 3.

3.2 Natural Gas Prices in Peru

75. Natural gas prices for power generation in Peru are among the lowest in the world (Table 3.1), largely as a consequence of the pricing policy that has set a cap on the Camisea wellhead price for power generation.

Table 3.1: Natural Gas Prices (Pipeline), 2008

	Gas Price, \$/mmBTU
Peru, see Table 3.2 for details	2.15
Vietnam, Phu My complex	3.20
Georgia (imports from GAZPROM)	3.50
Vietnam, Ca Mau CCGT, ^a 2008	6.00
Azerbaijan (imports from Russia)	6.77

a. Price formula in US\$/mmBTU = US\$1.17 (for transportation) + US\$0.45. (Singapore spot price for fuel oil as US\$/mmBTU.)

76. The 2008 prices set by the Supervisory Commission for Investment in the Energy and Mining Sector (*Organismo Supervisor de la Inversión en Energía y Minería*, OSINERGMIN) for thermal generators using Camisea gas are shown in Table 3.2. The average used in this report as the present (financial) gas price is US\$2.15 per million British Thermal Units (mmBTUs).

**Table 3.2: 2008 Regulated Gas Prices
for Thermal Power Generation in the Lima Area (US\$)**

	Ventanilla	Santa Rosa	Chilca	Kalpa
Price at Camisea	1.3065	1.3753	1.3753	1.3961
Transmission	0.7398	0.7398	0.7392	0.7402
Distribution (Chilca-Lima)	0.1218	0.1218		
Total	2.1681	2.2369	2.1145	2.1363

77. These (financial) prices are exceedingly low. The long term *economic* price of natural gas in Lima relevant to calculate the economic viability of the candidate hydro projects is likely to be significantly higher.

3.3 Economic Value of Natural Gas Based on Netback Values

78. An effort was made to estimate the long term economic cost of natural gas in Peru through a netback value approach,²⁷ that is, an estimation of the value of natural gas in its alternative uses: the maximum price that different types of consumers would be willing to pay for gas. This implies the use of two distinct approaches:

- An estimate based on the cost of a relevant substitute (in industrial use, residential, commercial activities); netback estimated as the maximum price

²⁷ “Peru Natural Gas Study,” Anexo 4: Valoración del Gas, 2008, draft report, World Bank.

consumers would be ready to pay for gas before switching to another energy source.

- When there is no substitute, based on the value of the output (petrochemicals, liquefied natural gas [LNG]). Here, the netback is computed as the value of the output less the costs associated to the production of the specific output (for LNG, an estimate of future Henry Hub²⁸ price minus costs of transport, liquefaction, and gasification).

79. The netback analysis concluded that LNG and petrochemical exports have the lowest netback values among the alternative uses. These values are around US\$3.1/mmBTU at the wellhead (Camisea), for a base case, long-term scenario characterized by crude oil prices of US\$75 per barrel.²⁹ To obtain the value of gas for power generation, the transportation economic costs (US\$1.3/mmBTU)³⁰ to the Lima gas-fired power-generating complexes must be added to the LNG netback values at the Camisea Gas Field.

80. The resulting economic prices of natural gas for power generation in the Lima area are presented in Table 3.3 as a function of oil prices scenarios, which in turn are linked to North American prices for LNG. While in recent months the link between prices of oil and natural gas appears to have broken, these products have inherent links in its production and consumption (as competing fuels) and, hence, irrespective of short term volatilities in the prices of either fuel, they keep a strong long term relationship. The economic assessment of hydropower plants –whose economic life is of 25 years or longer- is based on these long term trends.

Table 3.3: Economic Value of Natural Gas

Oil Price	Economic Gas Price (LNG export netback)
US\$/bbl	US\$/mmBTU
37	2.14 (present gas price)
75	4.4
100	5.9
125	7.3

81. Figure 3.1 presents a demand curve for natural gas for a 25-year period, including all gas uses except the demand for power; that is, the curve reflects the willingness to pay for gas in case it is not used in power generation. Prices correspond to the netback values of gas for different uses, starting (at the upper level) with vehicular natural gas (VNG)

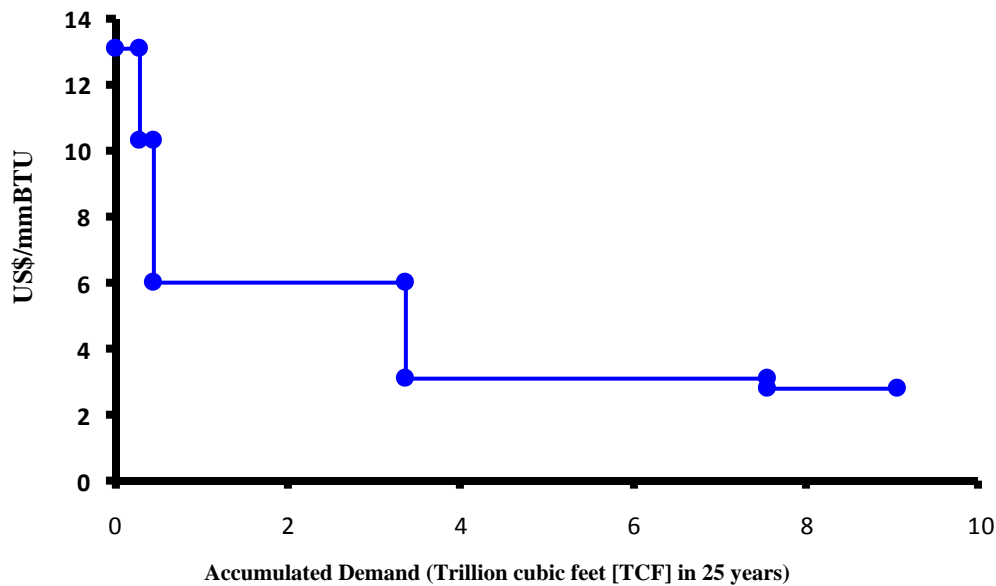
²⁸ The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States.

²⁹ Value equivalent to the World Bank’s latest long-term forecast for oil prices. While the extremely high volatility of oil prices of the last 12 months may add confusion to the analytical challenge, the estimation of gas netbacks, and the subsequent economic analysis of hydropower, are long-term exercises that focus on the mid-2010s and onward. From this point of view, an oil price of US\$75/bbl is considered a sound assumption for that period.

³⁰ This figure includes capital costs plus variable costs. In contrast, the lower figure of US\$0.74/mmBTU, shown in Table 3.2, and used in Chapter 4, refers to the regulated and subsidized prices, that is, a financial cost.

and moving subsequently to residential, commercial and small industry, large industry, and LNG and petrochemical (urea). It is worth noting that while the netback value of natural gas compared to LNG is directly linked to the prices of LNG in North America, when compared to its use in the large industry and petrochemicals (the other two uses of gas that yield low netback values), the gas netback is a direct function of two other variables: the prices of fuel oil and urea respectively.

Figure 3.1: Demand Curve for Natural Gas
 Netback at Generation Plant (US\$3.1 + US\$1.3 transport costs) =
 US\$4.4/mmBTU



3.4 The Economics of Electricity Generation in Gas-fired Plants

82. As discussed in Chapter 2, hydro construction costs have been adjusted to early-2008 price levels. To provide a valid comparison, it is important that OCCT and CCGT costs be assessed on a similar basis.

83. A comprehensive survey of power plant investment costs was recently prepared for the World Bank.³¹ Table 3.4 shows costs for a 140-megawatt (MW) combined cycle plant based on a heavy frame gas turbine (GT) at January 2008 price levels. Romania has the lowest costs at US\$1,140/kW.

³¹ URS, "Study of Equipment Prices in the Energy Sector," World Bank, Washington, D.C., 2008.

**Table 3.4: 140-MW Combined Cycle Plant
(US\$ million at January 2008 prices)**

	United States	India	Romania
OEM Price ^a	99.7	99.7	99.7
Total Plant Cost (as US\$/kW)	192.1	159.5	155.4
OEM	730	730	730
Balance of Plant	680	440	410
Total	1,410	1,170	1,140
OEM as % of Total	51%	62%	64%

a. Freight on board (FOB), excluding installation labor.

Source: URS (2008), Table 6.4.

84. The corresponding costs for an open cycle plant are shown in Table 3.5.

**Table 3.5: 150-MW Open-cycle Plant^a
(US\$ million at January 2008 prices)**

	United States	India	Romania
OEM Price ^b	34.0	34.0	34.0
Total Plant Cost (as US\$/kW)	76.3	64.1	68.7
OEM	240	240	240
Balance of Plant	190	200	240
Total	530	440	480
OEM as % of Total	45%	54%	50%

a. Heavy frame GT.

b. FOB, excluding installation labor.

Source: URS (2008), Table 6.3.

85. These costs are significantly higher than the capacity cost used by OSINERGMIN as the basis for the calculation of the capacity charge in the generation tariff. OSINERGMIN's practice is to take the average U.S.-dollar-denominated cost of simple cycle turbines over the past five years, with estimates for the May 2007 capacity charge calculation, as shown in Table 3.6. Clearly, the OSINERGMIN approach does not give adequate weight to the balance of plant costs, nor does it reasonably reflect the capital cost of building a new greenfield-site project, particularly in a market that has shown high volatility in recent years.

Table 3.6: OSINERGMIN Capacity Charge Calculation

	Peru, OSINERGMIN ^a	India (from Table 2.3)
OEM price	33.2	
Total plant cost (as US\$/kW)	6.5	
OEM	189.6	240
Balance of plant	37.0	200
Total	226.0	440
OEM as % of total	16%	54%

a. Excluding interest during construction of US\$2.7million.

Source: OSINERGMIN, Fijación de los Precios en Barra (periodo Mayo 2007–Abril 2008), Cuadro L.4

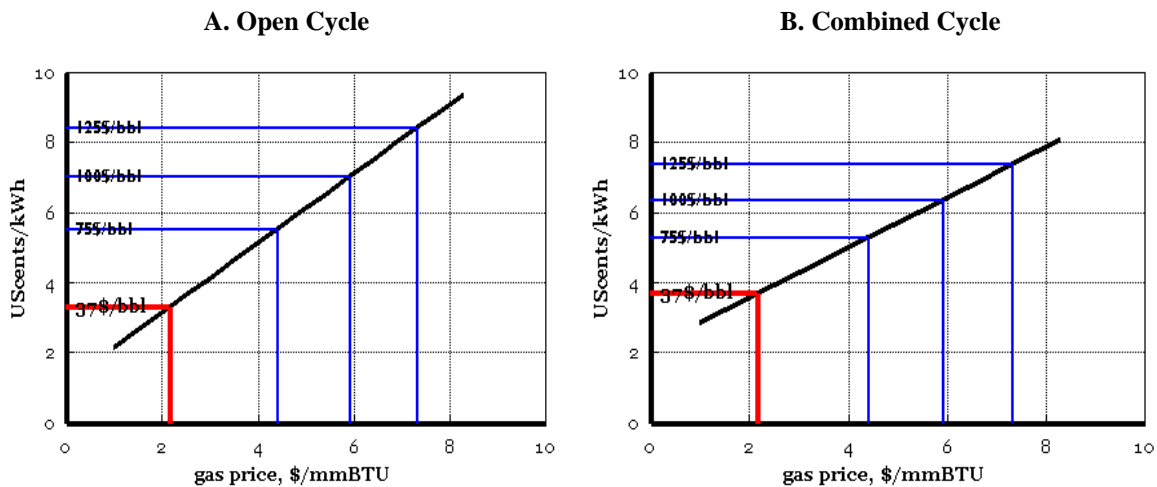
86. In the interest of assuring a conservative result, we assume for the avoided cost calculation an economic capital cost of US\$875 per kilowatt (kW) for CCGT, (based on the average of the World Bank study estimate of US\$1,150/kW and the widely cited cost of US\$600/kW for CCGT typical of generation planning studies conducted over the past few years), and US\$460/kW for open cycle plants (the average of the estimates for India and Romania in the World Bank study). The resulting generation costs are shown in Table 3.7, based on annual load factors of 65 percent,³² for a discount rate of 12 percent.

Table 3.7: Generation Costs at 65 Percent Load Factors

Oil Price US\$/bbl	Economic Gas Price (LNG export netback) US\$/mm BTU	CCGT Generation Price US¢/kWh	OCCT Generation Price US¢/kWh
37	2.14	3.7	3.3
75	4.4	5.3	5.6
100	5.9	6.4	7.1

87. At the present gas price, it is clear that there is little incentive to use combined cycle, since generation in open cycle plants is significantly lower (US3.3¢/kWh) than in combined cycle units (US3.7¢/kWh) as can be seen in Figure 3.2. The break-even gas price above which combined cycle would be justified is around 3.7 US\$/mmBTU.

Figure 3.2: Generation Costs Compared to Gas and Oil Price

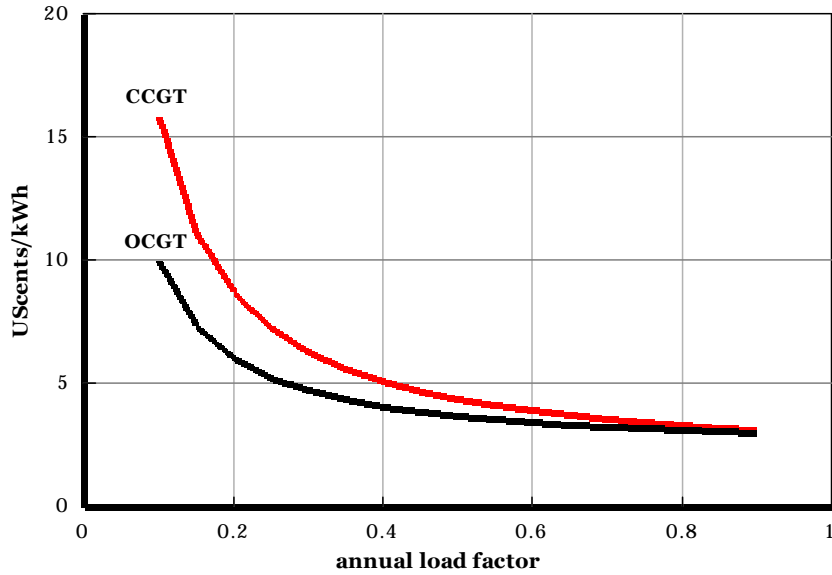


88. The consequences of the low gas price can be illustrated in a different way, as shown in Figure 3.3, which shows generation costs as a function of annual load factor.

³² In 2007, the 348-megawatt (MW) Chilca OCCT generated 1,956 gigawatt-hours (GWh), an annual load factor of 64 percent. By normal standards, this is a very high annual load factor for an open cycle project. The 492 MW Ventanilla combined cycle project generated 2,919 GWh, an annual load factor of 67.7 percent.

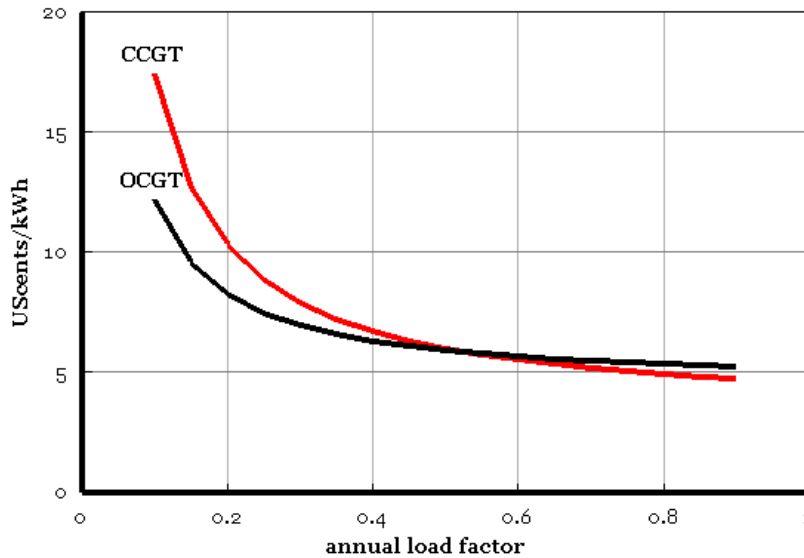
At current gas prices, open cycle generation is cheaper than combined cycle over the entire range of load factors.

Figure 3.3: OCCT Compared to CCCT Generation Costs, Present Gas Price (US\$2.14/mmBTU)



89. However, at an “economic gas price” of US\$4.4/mmBTU, combined cycle operation is cheaper at load factors of more than 50 percent (Figure 3.4).

Figure 3.4: OCCT Compared to CCCT Generation Costs, Present Gas Price (US\$4.4/mmBTU)



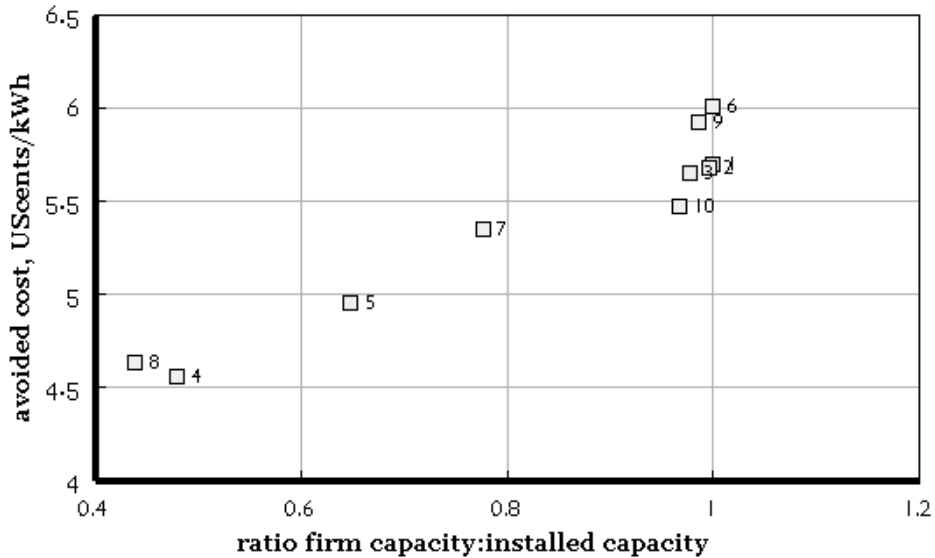
3.5 Economic Analysis of the Sample Projects

90. An economic analysis was conducted of the sample projects identified in Chapter 2. In addition to the valuation of benefits as discussed above, the following cost assumptions were made:

- **Construction outlays:** Most projects have a three-year construction time, with disbursements in year 1 of 33 percent of the total, in year 2 of 26 percent, and in year 3 of 41 percent.
- **Operating costs:** Taken as 1.5 percent of (overnight) capital cost per year, subject to a minimum amount of US\$1million/year.

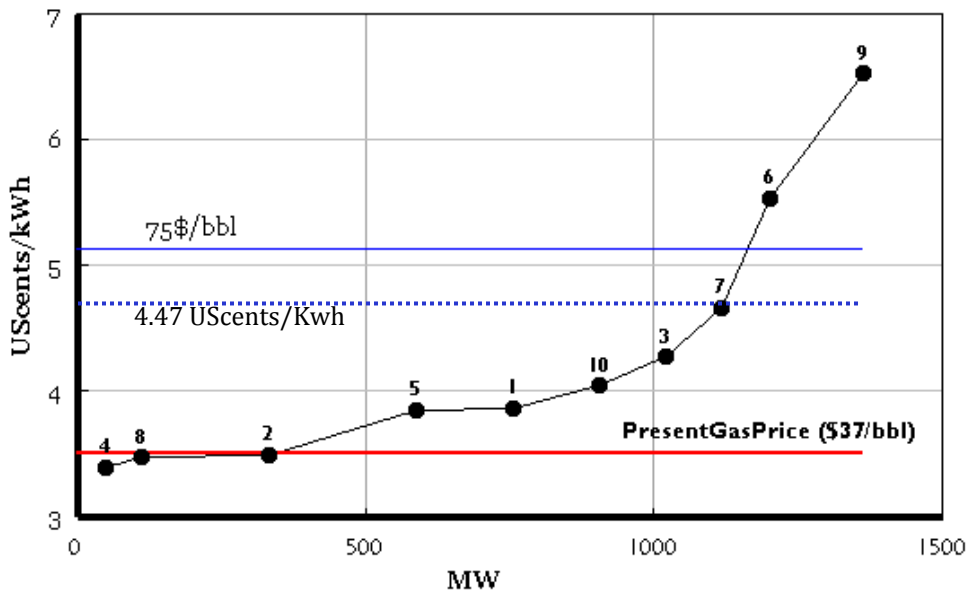
91. ***Benefits.*** Figure 3.5 shows the average level of benefits, in US¢/kWh, for the 10 sample projects. These range from a low of US4.5¢/kWh to a high of US6¢/kWh. The principal explanatory variable in this range is the firm capacity that the project offers to the system, which determines the extent of capacity benefits. Projects #4 and #8 have firm capacities of less than 50 percent of their installed capacity, and therefore have a correspondingly low benefit per kWh.

Figure 3.5: Benefits of Sample Projects Compared to Ratio of Firm to Installed Capacity



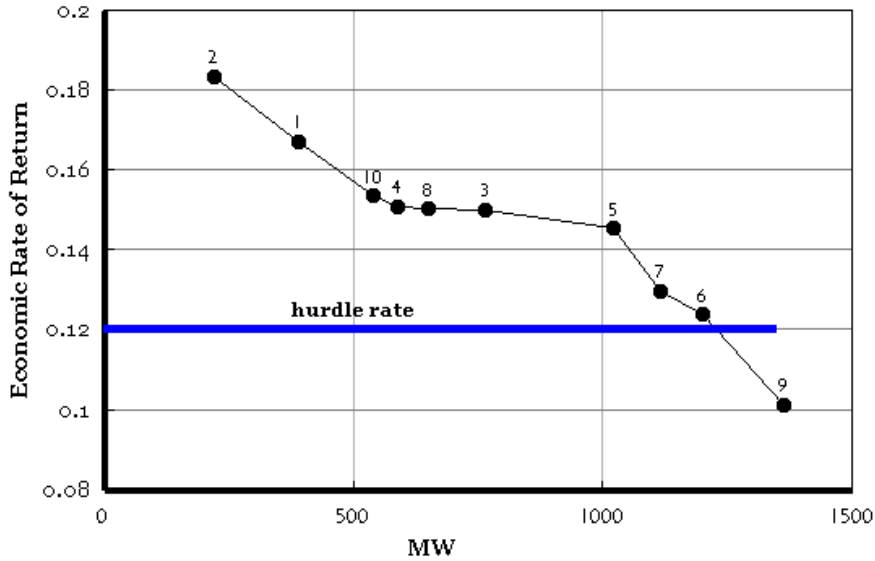
92. The results of the economic cost-benefit analysis can be displayed in the form of a supply curve, which shows the cumulative installed capacity at a given production cost. As shown in Figure 3.6, only two projects have production costs below the cost of gas-based generation (at the present gas price of US\$2.15/mmBTU, equivalent to US\$37/bbl). However, at an economic price of natural gas of US\$4.4/mmBTU (corresponding to the oil price scenario of US\$75 per barrel), 8 projects totaling 1,117 MW, have economic production costs lower than that for gas-fired generation. If the economic price of gas goes down to US\$3.7/mmBTU (for an oil price scenario of around US\$60 per barrel), 7 projects adding 1,020 MW would pass the economic hurdle.

Figure 3.6: The Hydro Project Supply Curve – Electricity Production Costs



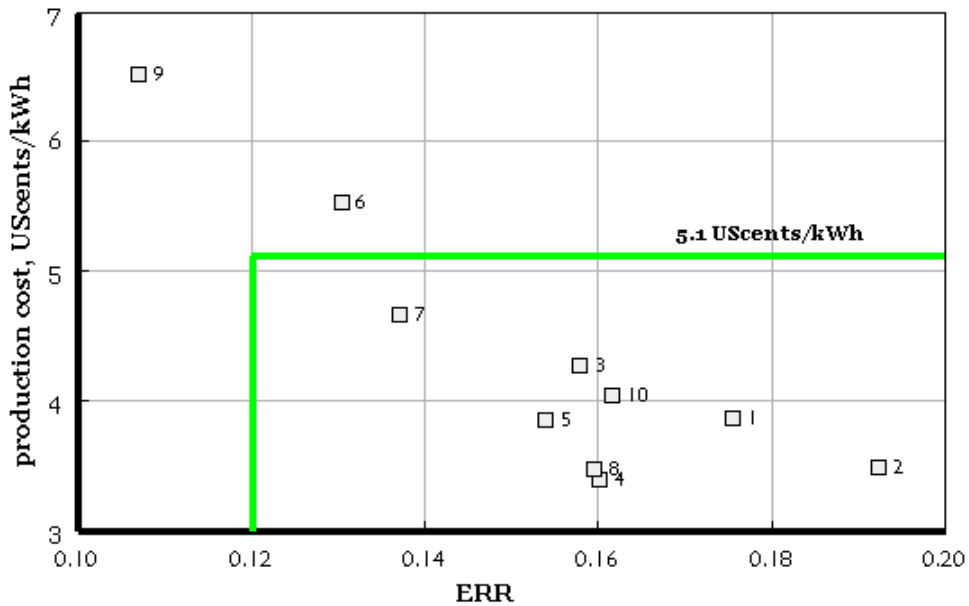
93. Whether a project with low production costs is economically viable depends also on the benefits (avoided costs), which are incorporated in the calculation of the economic rate of return (ERR). As shown in Figure 3.7, nine projects (1,201 MW) have an ERR greater than the 12 percent hurdle rate³³ at the economic price of gas.

Figure 3.7: Supply Curve (as Economic Rate of Return)



94. The box in Figure 3.8 shows projects that meet both the 12 percent hurdle rate *and* have production costs below gas generation, namely 8 projects accounting for 1,024 MW and 5,280 GWh.

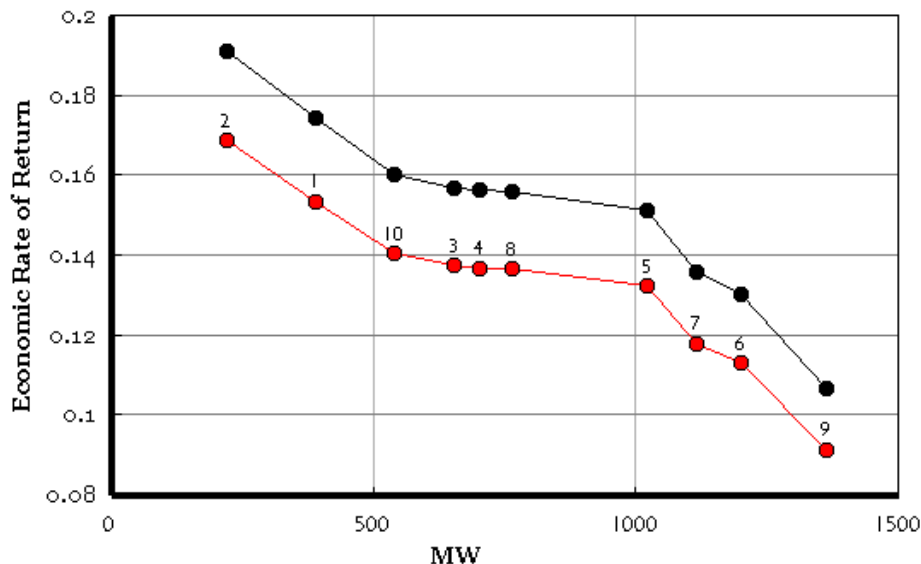
Figure 3.8: Productions Costs and Economic Rate of Return



³³ Hurdle rate used for public investments by the Ministry of Economy and Finance. (The hurdle rate is the required rate of return in a discounted cash flow analysis, above which an investment makes sense and below which it does not.)

95. The results of the economic analysis are sensitive to the assumed capital costs. A 20 percent capital cost increase reduces the economic projects from 8 (1,024 MW) to 3 (510 MW) at US\$75/bbl and US\$4.4/mmBTU gas price (Figure 3.9).

Figure 3.9: Impact of a 20 Percent Increase in Capital Costs



3.6 Local Environmental Benefits

96. In principle, the economic analysis should also take into consideration the avoided *local* environmental damage costs of the fossil-fuel generation that it displaces—and indeed in many countries—most notably China—the damage costs from coal-fired generation in particular are a major incentive for hydro and renewable energy projects (and where the benefit can be as much as US1¢/kWh).

97. However, in Peru, most of the thermal generation is located in a sparsely populated area some 60 kilometers south of Lima. Gas-based power generation has no significant particulate or sulphur emissions, and only nitrogen oxide (NOx) emissions are of major concern. But with low population density in the area, and the predominating weather regime being land and sea breezes (blowing emissions either over the ocean or into the even less-sparsely-populated mountain area to the east, rather than north into the Lima metropolitan area), there is no evidence of power sector emissions causing human health damage or acid-rain-related consequences on agriculture or buildings. Lima itself is suffering from increased air pollution problems, but these are the result of automobile emissions, which are orders of magnitude greater than the power plant emissions.

98. In the absence of any evidence of reliable damage cost estimates attributable to power generation in Peru, there are no grounds for including these in the economic analysis.

3.7 Global Environmental Benefits

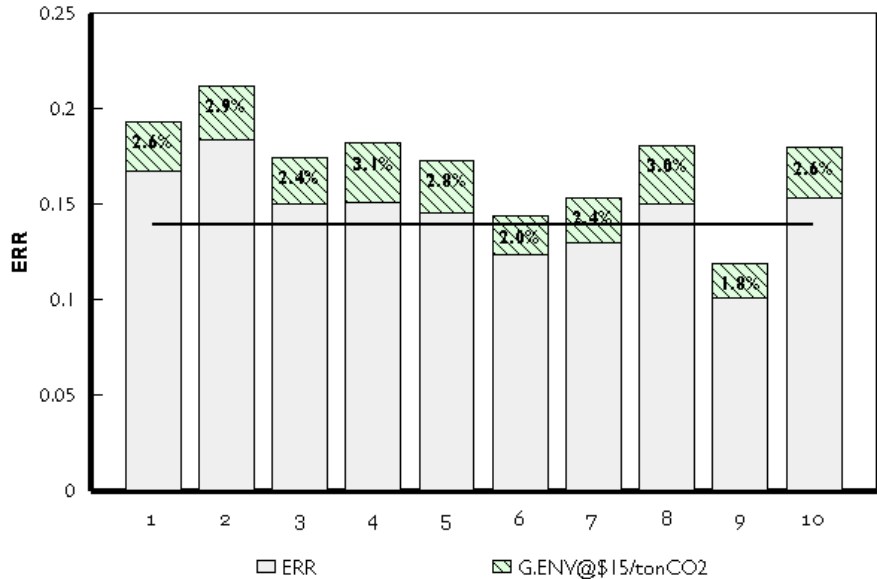
99. However, in the case of avoided greenhouse gas (GHG) emissions, the relevant benefits are easily quantified. Avoided carbon emissions are valued at US\$15 per ton carbon dioxide (CO₂, with an emission factor of 0.57 kilograms per kilowatt-hour (kg/kWh), based on the recently approved Clean Development Mechanism (CDM) registration for Caña Brava.³⁴

100. These benefits are assumed to hold over the entire lifetime of the project, that is, independent of any assumptions about the renewal of the Kyoto Protocol in 2012, and the ability of renewable energy projects to sell the carbon offsets in global carbon markets.

101. The results are shown in Figure 3.10. Avoided GHG emission benefits are purely a function of total energy, and therefore the biggest impact of including their benefits will occur in the plants with the highest annual load factors. The additional ERR ranges from 1.8 percent to 3.1 percent, and two projects (#6 and #7) become economically viable as a result of the inclusion of these benefits (that is, the 12 percent hurdle rate is exceeded by their inclusion).

³⁴ The baseline emission factor for the 5.67 MW Caña Brava small hydro projects is 0.56927 kg CO₂/kWh (*Caña Brava CDM Project Design Document*).

Figure 3.10: Impact of Avoided GHG Emission Benefits on ERR

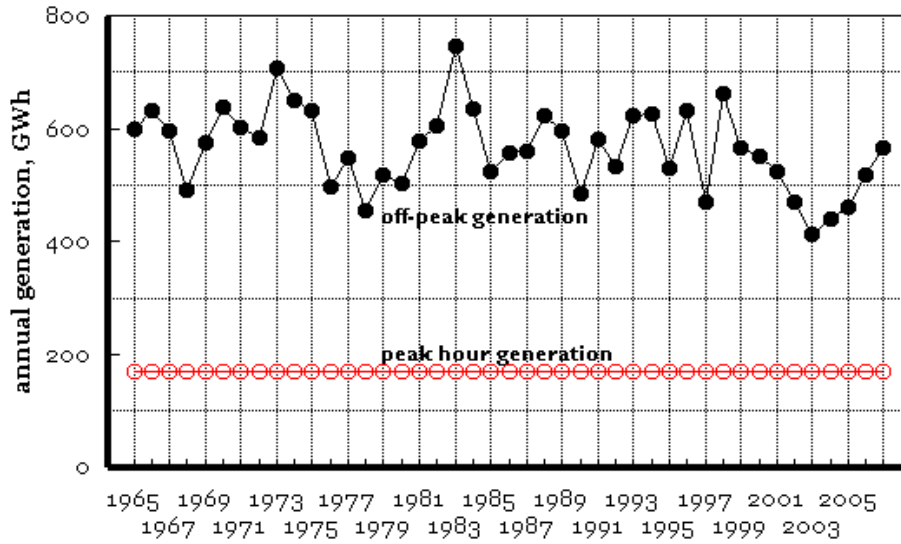


3.8 The Negative Impacts of Climate Change

102. While the climate change benefits of hydropower are readily quantified (since the global market for carbon credits serves as a proxy for the monetary benefits), the quantification of the potential negative impacts of climate change on hydro generation is more difficult, and the impacts are subject to high levels of uncertainty. While some effects are already being observed, notably the reduction of flows in power plants or projects that are or would be fed by the melting of glaciers, other potential consequences—such as the possible changes in rainfall patterns—could have a much more important impact, positive or negative. However, these impacts cannot be quantified at this stage since there is still a great deal of uncertainty about the nature and magnitude of this impact.

103. Only 2 of the 10 projects assessed feed from a considerable contribution of glaciers. In such cases, the most likely consequence is that, once the glaciers are lost, dry season inflows will be reduced. This has potentially more serious implications for run-of-river schemes without daily peaking storage, since plants with daily storage would be able to continue generating at peak hours during the season. In fact, due to this economic advantage, most projects are designed with adequate daily storage facilities. For such plants, peak-hour generation (of higher economic benefit) may be relatively unaffected, with most of the reduction occurring in the off-peak hours. This is already observed in the historical generation patterns during dry years: peak-hour generation is relatively unchanged. See Figure 3.11 for a simulation of generation in a project fed considerably by glaciers.

Figure 3.11: Annual Peak and Off-peak Generation, Typical Project



104. Table 3.8 shows the results of an illustrative calculation, in which it is assumed that dry season inflows are reduced by 20 percent. In this case, the annual plant factor declines from 61 percent to 55 percent, with a reduction in the project’s ERR from 14.7 percent to 13.7 percent.

Table 3.8: Potential Impact of Reduced Dry Season Flows on a Typical Project

	Baseline	Reduced Flows
ERR	14.7%	13.7%
Production cost, US¢/kWh	4.34	4.75
Load factor	0.61	0.55
Annual generation, GWh	775	705

3.9 Conclusions on Economic Analysis of Hydropower Projects

105. This economic analysis suggests that hydroelectric projects remain economically viable even given recent cost escalation, when natural gas prices reflect the full economic value of natural gas in alternative uses. In the sample of projects examined, all fairly advanced in their preparation, about 1,020 MW would be economically viable if gas were to be valued at its economic cost (opportunity cost) of around US\$4.4/mmBTU. Compared to gas-based projects, the economic cost of hydrogeneration is about US1¢/kWh cheaper. This would imply economic savings of around US\$50 million per year if these projects are implemented. These results are not very sensitive to the economic value of gas; if this value goes down by 15 percent (down to US\$ 3.7/mmBTU) only one of eight projects would cease to be economically attractive.

106. At the present price of gas (US\$2.14/mmBTU), hydro projects would not be competitive. However, with further expansion of gas-based projects constrained by capacity limits of the Camisea pipeline, new gas-fired plants would face the higher production costs of new gas fields plus either the costs of additional pipeline capacity or, if the gas plants were sited at the gas fields, the corresponding cost of additional transmission capacity to the main load centers.

107. From the perspective of efficiency, the most desirable policy response is to price gas at its economic value rather than at its financial cost. While this gas price increase may be politically unacceptable, it should be acknowledged that the current level of gas prices for power generation will not be sustainable in the future and, hence, it will be necessary to revise the current pricing policy. Whichever the impact of such adjustment on electricity tariffs, poor consumers with low levels of consumption would experience a much smaller impact because of the Electricity Compensation Fund (Fondo de Compensación Social Eléctrica, FOSE) equalization.

Box 3.1: Tariff Impacts of Adjusting the Gas Price to its Economic Level (for 2007)

In 2007, sales to the free and regulated markets were 24,716 gigawatt-hours (GWh). Total billing was US\$1,830 million (row 6 of the table), for an average tariff of US7.4¢/kWh (row 7).

Impact of Gas Price Increases

Gas Price	US\$/mmBTU	2.14	3	4	4.4
		Present Price			Economic Price
1. Public lighting	(GWh)	656			
2. Commercial	(GWh)	4,651			
3. Industrial	(GWh)	13,649			
4. Residential	(GWh)	5,759			
5. Total	(GWh)	24,716			
6. Total billing	US\$m	1,830			
7. Average tariff	US¢/kWh	7.40			
8. Gas generation	(GWh)	7,313	7,313	7,313	7,313
9. Heat rate	kCal/kWh	2,500	2,500	2,500	2,500
10.	BTU/kCal	3.968	3.968	3.968	3.968
11. Generation cost	US\$/kWh	0.0213	0.0298	0.0397	0.0436
12. Gas bill	US\$m	156	218	290	319
13. Total billing	US\$m	1,830	1,892	1,964	1,993
14. Increase	US\$m		61.7	134.2	163.2
15. Tariff	US¢/kWh	7.40	7.65	7.95	8.06
16. Increase in tariff	US¢/kWh		0.25	0.54	0.66
17.	(%)		3.4%	7.4%	8.9%

kcal = Kilocalorie.

Source: OSINERGMIN, *Anuario Estadístico 2007*.

Assuming all gas generation is in open cycle plants (the OSINERGMIN statistics do not provide an itemization of the generation in the Ventanilla combined cycle plant), and at an average heat rate of 2,500kcal/kWh, the 2007 gas bill (at the average price of US\$2.14/mmBTU) is US\$156 million, that is, 8.5 percent of the total billing.

The table shows the increase in the gas bill at increasing levels of the gas price. At the economic price of US\$4.4/mmBTU, the gas bill would be US\$319 million, resulting in an average tariff increase of US0.66¢/kWh, or 8.9 percent.

This is an order of magnitude calculation aimed at exploring the impact of a gas price adjustment based on a full recovery approach (i.e. the basic principle of the Peruvian pricing policy). Two simplifying assumptions (that consumer demand is price inelastic and the absence of more efficient combined cycle plants in the calculation) suggest that the increase could actually be smaller. With a price increase, consumption would go down a bit, reaching equilibrium at a lower tariff and, also, a more efficient use of gas would reduce the increase in the gas bill.

4. FINANCIAL VIABILITY OF HYDROPOWER

108. This chapter assesses the financial viability of hydropower in Peru within the current global context. To that end, it assesses a set of hydropower projects, with special attention to the impact of different financing options, ranging from a pure commercial financing to a traditional public sector project with International Financing Institutions (IFI) financing. The chapter also discusses the risks associated with hydropower financing and the impact of the global financial crisis.

4.1 Assumptions for Financing of Projects

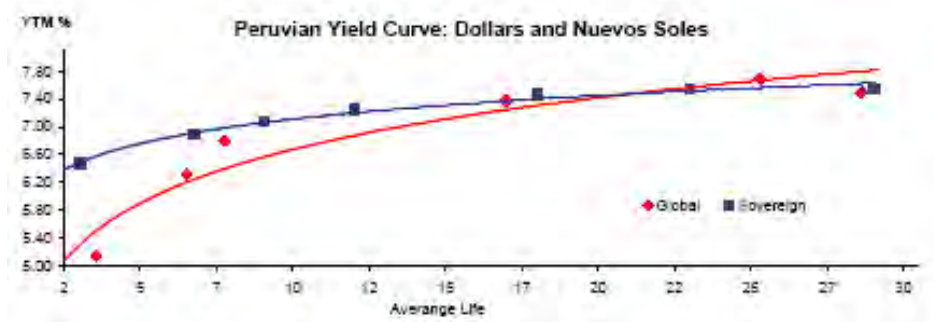
4.1.1 Assumptions for Long-term Commercial Financing of Projects

109. The basis for long-term commercial financing is likely to be the relevant yield curve (the relationship between interest rate and maturity (t) of a debt for a given debt and currency, and is generally an increasing function of (t)). Peruvian yield curves track global interest rate trends, and have fallen significantly over the past few months; while in October 2008, the 10-year Soles rate was around 9.5 percent, by early February 2009, the rate had dropped by 2 percent to around 7.5 percent (Figure 4.1).³⁵

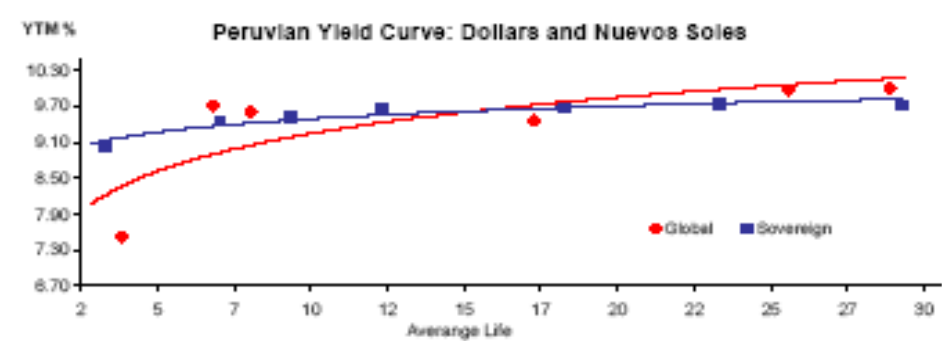
³⁵ However, this is still above typical rates in 2007: In September 2007, the 10-year Soles rate was around 6 percent.

Figure 4.1: Peruvian Yield Curve

A. January 2009



B. October 2008



Source: Peru Ministry of Economy and Finance, *Daily Report*, January 27, 2009 and October 22, 2008.

110. For the financing options that involve the IFIs, the basis for interest rates can be taken as the six-month London Interbank Offer Rate (LIBOR).³⁶

111. As shown in Table 4.1, LIBOR rates fell sharply during the fourth quarter of 2008, with the six-month U.S. dollar LIBOR falling from 4.17 percent to 1.62 percent. The pound sterling LIBOR fell by almost 4 percent during the same period.³⁷

³⁶ The volatility of the LIBOR has been much in the news of late in the context of the global financial crisis. However, it is the overnight LIBOR rates that have been the focus of this attention: these are currently more than 1 percent lower than the six-month rates.

Overnight LIBOR Rates

	Oct. 1 2008	Oct. 16 2008	Jan. 23 2009
JPY	1.16	0.87	0.220
US\$	3.79	1.93	0.236
Euro	4.26	3.75	1.125
GBP	4.96	5.17	1.530

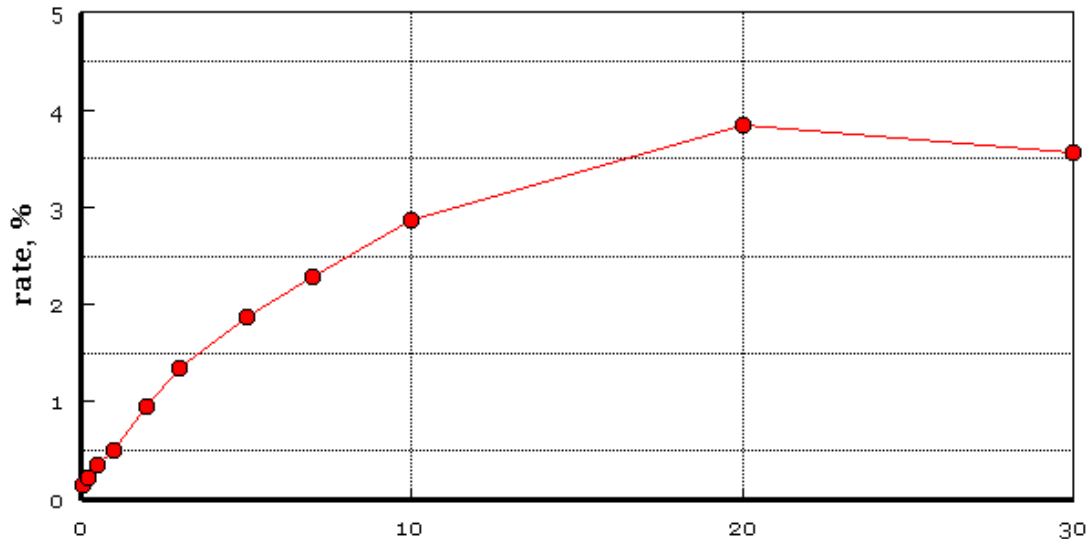
³⁷ LIBOR rates can be found at: www.bba.org.UK.

Table 4.1: Six-month LIBOR

	2008			2009
	Jan. 1	Oct. 1	Oct. 16	Jan. 23
JPY	0.97	1.08	1.17	0.87
US\$	4.56	4.03	4.17	1.62
Euro	4.70	5.39	5.15	2.29
GBP	5.85	6.39	6.31	2.37

112. However, the variable rate can also be converted into a fixed rate using an interest rate swap,³⁸ in which a set of floating rate payments is converted into a set of fixed rate payments based on a notional principal. An interest rate swap is essentially a series of forward contracts for future interests, so the pricing of the swap will be related to the yield curve. For example, on January 20, 2009, the U.S. Federal Reserve Bank quoted a 10-year interest rate swap (for three-month LIBOR) at 2.89 percent.³⁹ The corresponding U.S. Treasury yield curve is shown in Figure 4.2: the 10-year rate is 2.87 percent. Therefore, for the illustrative calculations of IFI financing of this chapter, 2.89 percent is used as the relevant interest rate.⁴⁰

Figure 4.2: U.S. Treasury Yield Curve (January 29, 2009)



³⁸ A fixed for floating interest rate swap is often referred to as a “plain vanilla” swap, simply because it is the most commonly encountered structure. These derivatives can themselves be hedged on the Chicago Board of Trade interest rate swap futures.

³⁹These can be found at: www.federalreserve.gov/releases/h15/update.

⁴⁰ Interest rate swaps (and other derivative contracts such as copper swaps on the London Metals Exchange) are routinely used by the big Peruvian mining companies to hedge their exposure to volatile market conditions.

4.1.2 Equity Returns Required on Hydropower Projects

113. This report uses a hurdle rate for post-tax financial returns of 17.5 percent on hydropower projects, which is based on discussions with potential equity investors and fund managers who cite target returns of 15 to 20 percent (see Box 4.1).⁴¹

Box 4.1: Equity Returns

Investment hurdle rates for private companies are rarely revealed, in part because hurdle rates are dependent upon the sponsor's perception of risk: the higher the risk, the higher the return that is sought. The principal risk of a hydro project in Peru, from both the investor's and the lender's perspective, is *completion* risk; as a project moves from pre-feasibility study to feasibility study to financial closure and then through the various stages of construction, this risk gradually diminishes. An investor who puts up equity at the detailed feasibility study stage (which for a large hydro project can be substantial) expects a much higher return than one who joins at the start of construction (where the extent of actual geotechnical surprise is still largely unknown).

Peruvian asset and pension funds are potential sources of equity for infrastructure projects, and they are less reluctant to state targets for returns, which were stated to us as being in the 15 to 20 percent range (with greenfield projects at the high end of this range, acquisition of operating assets at the lower end). Some fund managers expressed the view that mitigating completion risks was seen as requiring completion guarantees and the involvement of international engineering, procurement, and construction (EPC), not higher financial rates of return.

Mining companies and industrial conglomerates may have entirely different investment objectives. For some, investment in a hydro project is largely a long-term hedge against the possibility of electricity supply shortages, which can have a devastating impact on operations if they do occur.

Source: "Peru: Institutional and Financial Framework for Development of Small Hydropower," World Bank, in publication.

4.1.3 Other Assumptions for Financial Analysis of Hydropower Projects

114. The following general assumptions are also made for the financial analysis:

- **Construction disbursement:** Equity contributions in the construction phase are *pari passu* with debt.
- **Corporate tax:** The standard rate of corporate tax is 30 percent, and there are no holidays or reduced rates. There are tax concessions in the region of Loreto

⁴¹ Hydro developers interviewed were reluctant to divulge their hurdle rates as financial returns to equity, but one cited a minimum rate of 12 percent for what is understood to be "projects financial return," that is, a return including all taxes and transfer payments, and benefits measured at the actual revenue stream (rather than at economic prices), but independent of financial structure. The credibility of the assertion that decisions were made based on such returns is difficult to assess and could be viewed with skepticism. Indeed, discussions with the major commercial banks revealed widespread use of lease deals for thermal and transmission line projects (which, among other advantages, effectively allow immediate recovery of the value-added tax [VAT]), so tax considerations for the large mining and industrial companies are clearly of major importance.

(Amazonas) for *all* projects, not just power projects, but this requires a corporate office in Loreto to qualify.

- **Depreciation:** As specified in Table 4.2 for conventional financing. However, under the new rules, accelerated depreciation to as short a period as five years is allowed for hydro projects.
- **Water “royalties”:** Generally imposed at 1 percent of sales revenue; 0.6 percent is paid to the OSINERGMIN, 0.4 percent paid to the Ministry of Energy and Mines (MEM).
- **Front-end and commitment fees:** Assumed to be zero.
- **Escrow requirements:** Neither major maintenance nor debt service escrows are considered.

Table 4.2: Depreciation Rates (years)

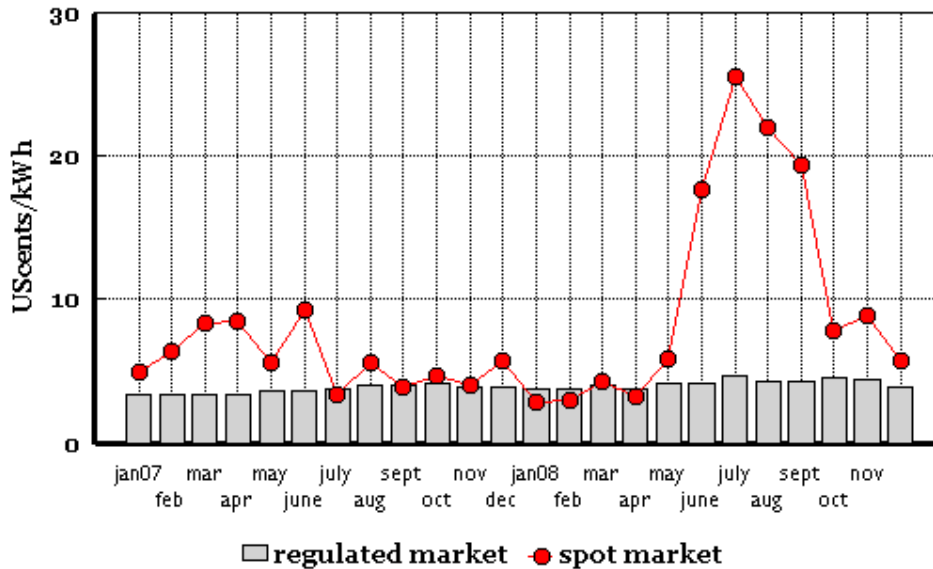
	Civil Works	Mechanical and Electrical
Lease	5	2
Conventional Financing	33	15

- **Import duty:** None (hydroelectric equipment has been exempted).
- **VAT:** Although construction periods for the hydro projects considered in this report are two to three years (and shorter than the nominal four-year period under which immediate recovery for hydro is allowed), since the four-year period is considered to run from the date of the concession rather than the date actual construction begins, the VAT is effectively recoverable immediately, and the VAT rate can therefore be taken as zero.

4.2 Financial Internal Rate of Return (FIRR) for the Typical Project under Recent Market Conditions

115. In mid-to-late 2008, there was a significant increase in spot market prices. Since the system assures that hydro will always be dispatched, this has led to substantial profits for existing hydro projects, and expectations among potential hydro project developers that future prices may make new hydro projects financially viable (Figure 4.3). Whether such high prices will persist through 2009 is unclear.

Figure 4.3: Regulated Market Energy Prices Compared to Marginal Energy Costs^a: Peak Hours



a. Excluding capacity charge.

Source: “Operación del Sector Eléctrico, Reporte Estadístico,” OSINERGMIN, Septiembre 2008 y Diciembre 2007.

116. The revenues of a typical project (as defined in Box 4.2) are based on the following assumptions:

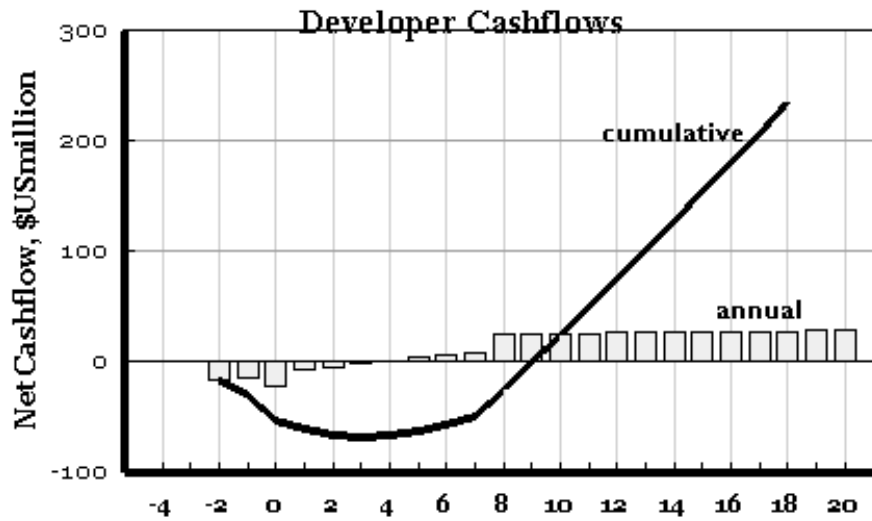
- 60 percent sales in a regulated market, 40 percent on the spot market with prices based on 2007 monthly averages. These correspond to the shares of firm and non-firm energy in the typical project.⁴²
- No revenues from carbon credits.
- OSINERGMIN capacity payments.⁴³
- Average financial price of US4¢/kWh.

117. Nevertheless, as shown in Figure 4.4, the cash flows in the first few years are negative, and even with the incentives, payback periods are long. The achieved FIRR is significantly below the assumed hurdle rate of 17.5 percent.

⁴² The annual firm energy of a hydropower project is defined as the summation of the lowest monthly energy production values for a hydrological energy production period of 30 years. The firm capacity is computed for the lowest month, taking into account the daily regulation capability of the specific plant.

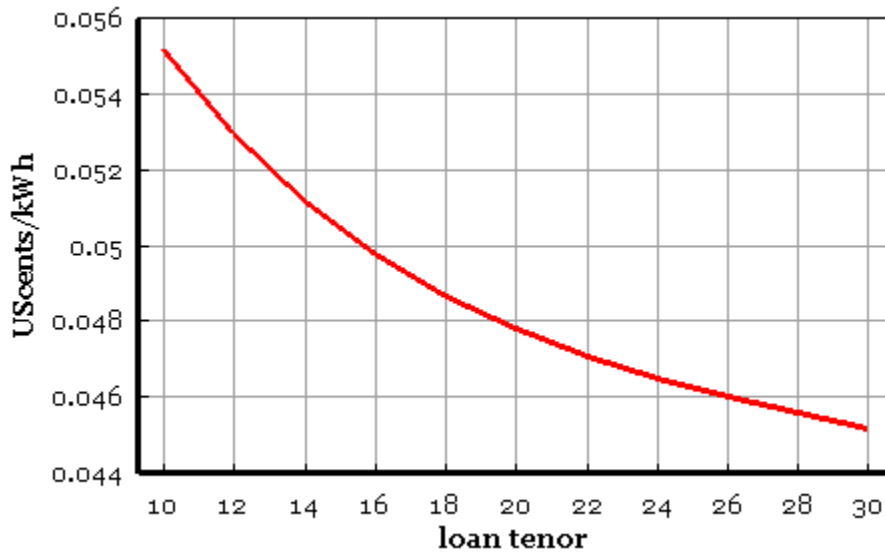
⁴³ See Table 3.6 for the calculation of this charge.

Figure 4.4: Developer Annual Cash Flows, Commercial Financing



118. In order to reduce costs (or increase FIRR), much longer loan tenors than 10 years are required. Figure 4.5 shows the decrease in required energy price (keeping constant the 17.5 percent hurdle rate): increasing the loan tenor from 10 to 20 years reduces the energy price considerably from US5.5¢ per kilowatt-hour (kWh) to US4.8¢/kWh.

Figure 4.5: Impact of Longer Loan Tenors on Total Financial Energy Price (Typical project, commercial finance, January 2009 interest rate conditions)



4.3 Analysis of the Financial Viability of Hydropower Projects under Different Financing Scenarios

119. To examine the impact of alternative financing methods on the sample of projects analyzed in Chapters 2 and 3 and on the typical project, five scenarios are considered:

1. Normal commercial finance (based on the balance sheet of the corporate sponsors, that is, the only option available in recent years)
2. Project finance (that is, without recourse to the balance sheet of the sponsors)⁴⁴
3. Development Bank finance (along the lines of the Brazilian model)
4. IFI finance (blended with commercial finance)
5. Traditional public sector finance (IFI only).

120. The calculations are presented for the typical project, and take the form of the total financial price required per kilowatt-hour produced, in order to achieve the target equity return of 17.5 percent for a private sector project (14 percent for a public sector project). Calculations also include the necessary price of firm energy to achieve the hurdle rate. It is assumed that capacity payments will be made separately, as per the OSINERGMIN formula (US\$55/kW/year), and based on estimates of the remunerable capacity for each project, and that non-firm energy would be sold at the spot market price. In other words, the total revenue requirements necessary to achieve the target FIRR of 17.5 percent are made up of:

- Revenue from firm energy (as may be bid in the proposed auctions), accounting for 60 percent of the output of the typical project)
- Capacity payments
- Sales of non-firm energy (40 percent of the output) on the spot market.

4.3.1. Commercial (balance sheet) Finance

121. Typical terms for a normal balance sheet financing are as follows:

- Interest rate: Yield curve + 2 percent spread (for prime corporate customers)
- Loan term: 10 years, including 3 years' grace (construction period)
- Debt: Equity 75:25.
- FIRR expectations: 17.5 percent.

122. Interest rates have been volatile, therefore, the results in Table 4.4 are presented for three different financing conditions: September 2007 (before the financial crisis, when

⁴⁴ El Platanal has been described as being a “project financing with recourse to corporate sponsors.” Such euphemistic descriptions cannot disguise the reality that it is really commercial financing. True project financing (as that term is normally understood) allows no recourse to balance sheets of, or guarantees from, corporate sponsors. Some large hydro Independent Power Producers based on project finance have various kinds of guarantees from IFIs (such as the Nam Theun 2 project in Laos from the World Bank and other IFIs), but lenders have no recourse from project sponsors (except to the extent of their project equity).

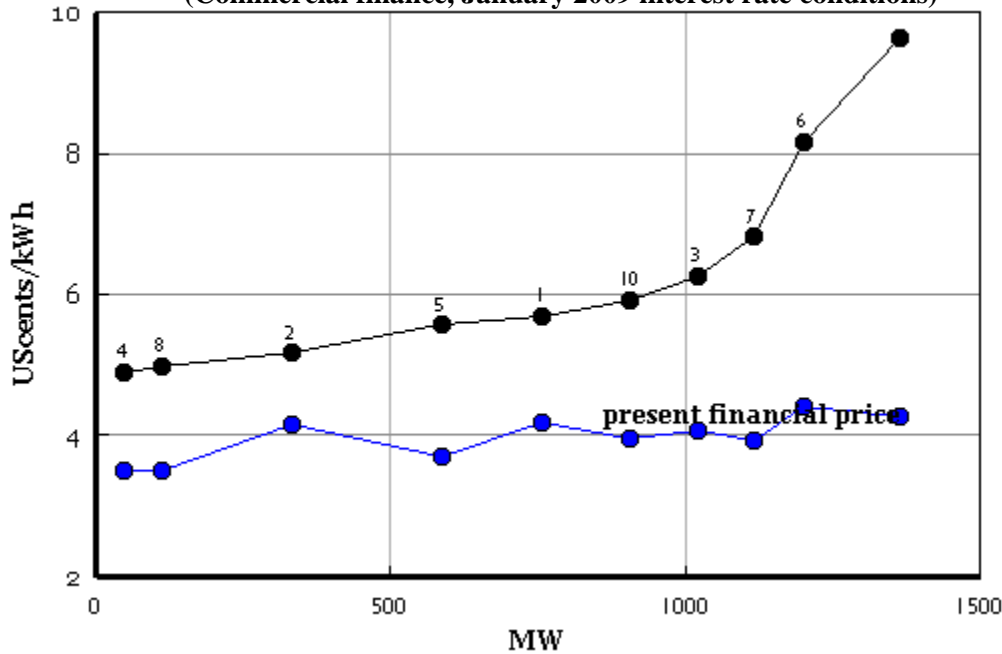
the Peruvians were still in a relatively good liquidity position); October 2008 (at the height of the collapse of the global financial system); and, as of the time of writing, end-January 2009 (when interest rates were again declining). The end-January estimated total financial price to achieve 17.5 percent FIRR is US\$5.52¢/kWh, and the price required for firm energy is US\$3.52¢/kWh, when the spot market price is assumed to follow the trends of 2007–08.

Table 4.4: Balance Sheet Financing

Conditions as of		Sept. 2007	Oct. 2008	End-Jan. 2009
Interest rates				
Six-month LIBOR	(%)	2.00%	3.75%	2.89%
Peruvian yield curve	(%)	6.00%	8.50%	7.50%
Revenue requirements				
Capacity charge	US\$m	5.29	5.29	5.29
Spot market sales (non-firm)	US\$m	9.78	9.78	9.78
Firm energy bid	US\$m	25.11	27.60	26.59
Total revenue requirements	US\$m	40.18	42.67	41.66
Firm energy bid price	US¢/kWh	3.32	3.66	3.52
Total financial price	US¢/kWh	5.32	5.65	5.52
Terms				
Equity	(%)	25%		
Term	(years)	10	(including grace)	
Grace	(years)	3		
Interest rate: yield curve plus		2.0%		
FIRR target	(%)	17.5%		

123. The variations across the sample projects can be shown in the form of a supply curve that shows the megawatts of capacity available at a total financial price per kilowatt-hour (that is, the total average financial price necessary to meet the revenue requirements to meet 17.5 percent FIRR; Figure 4.6).

**Figure 4.6: Supply Curve, Total Financial Cost to Meet 17.5 Percent FIRR
(Commercial finance, January 2009 interest rate conditions)**



124. None of the projects would achieve the necessary return on equity at the currently achievable estimated revenue, based on each projects' characteristic, of around US4¢/kWh, that is, the average revenue of each project under current conditions. As shown, this figure varies from about US3.5¢/kWh (for projects with low capacity payments) to US4.4¢/kWh.⁴⁵

4.3.2 Project Finance

125. Typical terms for project financing are as follows:

- Interest rate: Yield curve + 2% (prime corporate spread) + 3% project risk
- Debt: Equity 65:35
- Term: 10 years, including 3 years' grace (during the construction period)
- FIRR target 17.5 percent.

126. The higher equity requirements and higher interest rate simply reflect the higher risk to lenders in the absence of recourse to corporate sponsors. These would be very conservative assumptions, for, in reality, an actual project financing would contain several additional requirements that will increase the overall financing costs, including requirements for debt service and major maintenance escrows; the participation of international Engineering, Procurement, and Construction (EPC), which would increase construction costs; and various up-front fees and insurance requirements.

⁴⁵ This achievable price is the average revenue of each plant under current conditions and will depend on many project-specific factors, such as the OSINERGMIN determination of the payable capacity (*potencia remunerable*), and the mix of regulated market, spot market, and free market sales. Firm and non-firm energies are sold in markets, while capacity is regulated, that is, sold and paid, according to regulations.

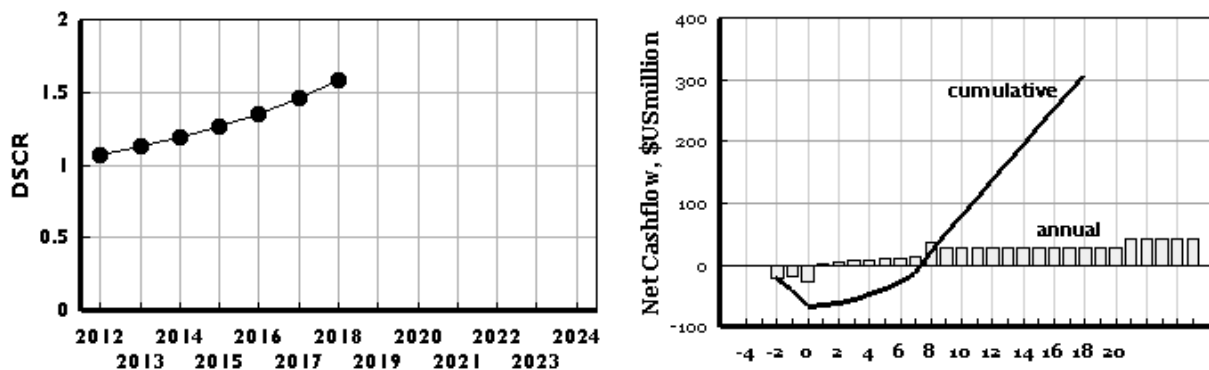
127. The results are shown in Table 4.5, again for the three interest rate scenarios. The January 2009 total financial price is US6.19¢/kWh, with a firm energy bid price of US4.17¢/kWh (compared to US3.52¢/kWh for balance sheet financing). This is a simple consequence of the higher financing costs associated with the higher risk to lenders when they have no recourse to corporate sponsors.

Table 4.5: Project Finance

Conditions as of		Sept. 2007	Oct. 2008	End-Jan. 2009
Interest rates				
Six-month LIBOR	([%])	2.00%	3.75%	2.89%
Peruvian yield curve	(%)	6.00%	8.50%	7.50%
Revenue requirements				
Capacity charge	US\$m	5.29	5.29	5.29
Spot market sales (non-firm)	US\$m	9.78	9.78	9.78
Firm energy bid	US\$m	30.33	32.59	31.68
Total revenue requirements	US\$m	45.40	47.66	46.75
Firm energy bid price	US¢/kWh	4.02	4.32	4.20
Total financial price	US¢/kWh	6.01	6.31	6.19
Terms				
Equity	(%)	35%		
Term	(years)	10	(Including grace)	
Grace	(years)	3		
Interest rate: yield curve plus		5.0%		
FIRR target	(%)	17.5%		

128. The Debt Service Coverage Ratios (DSCR) would likely be inadequate: a minimum DSCR of 1.25 to 1.35 would likely be required for a project financing, not achieved by our typical project, whose first year DSCR is 1.07 (Figure 4.7).

**Figure 4.7: DSCR and Cash Flows for a Typical Project:
Project Financing (January 2009)**



4.3.3 Development Bank Financing

129. In Brazil, hydro projects can be financed by the Brazilian National Development Bank (*Banco Nacional de Desenvolvimento Economico e Social*, BNDES) with much lower interest rates and longer loan tenors than currently available in a commercial or project financing. Typical terms would be:

- Interest rates: 6.25% plus a spread of 0.9% = 7.15%. This has remained unchanged since September 2007.
- Term: 16 years (BNDES offers a longer tenor of 20 years for projects greater than 1,000 MW).
- Debt: Equity 70:30.
- Grace up to six months after commercial operation (say, four years including three-year construction period).

130. The resulting firm energy price is US2.91¢/kW, with a total financial price of US4.91¢/kWh (Table 4.6).

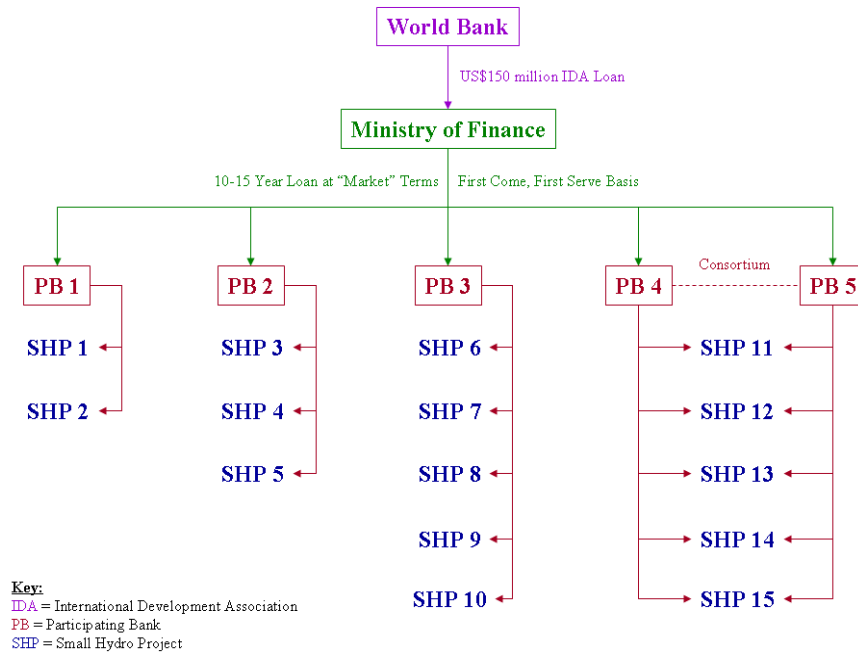
Table 4.6: Brazilian Model Development Bank Financing

Conditions as of		Sept. 2007	Oct. 2008	End-Jan. 2009
Interest rates				
BNDES	(%)	6.25%	6.25%	6.25%
Revenue requirements				
Capacity charge	US\$m	5.30	5.30	5.30
Spot market sales	US\$m	9.78	9.78	9.78
Firm energy bid	US\$m	22.0	22.0	22.0
Total revenue requirements	US\$m	37.1	37.1	37.1
Firm energy bid price	US¢/kWh	2.91	2.91	2.91
Total financial price	US¢/kWh	4.91	4.91	4.91
Terms				
Share		Equity 30%	BNDES 70%	
Term (including grace)	(years)		20	
Grace	(years)		4	
Interest rate	(%)		BNDES	
Plus	(%)		0.90%	
FIRR target	(%)		7.15%	

4.3.4 Blended Finance: IFIs and Commercial Banks

131. Several IFIs can offer loan tenors of up to 30 years, financed at LIBOR rates. For example, the World Bank has several projects (Sri Lanka, Turkey, and Vietnam) where it works with local commercial Banks to offer blended terms. In Turkey, the World Bank has provided US\$250 million and three local commercial banks another US\$250 million to create a fund for hydro project financing. Figure 4.8 illustrates typical arrangements (in this case, of the Vietnam project).

Figure 4.8: Refinancing Arrangements in Vietnam under the World Bank Renewable Energy Development Project



132. With such IFI participation, the debt portion would be split between commercial terms and IFI terms as follows:

- Equity 30%; IFI 35%; commercial loan: 35%.

Commercial terms:

- Interest rate: Yield curve + 2% (prime)
- Loan term: 10 years, including 3 years' grace.

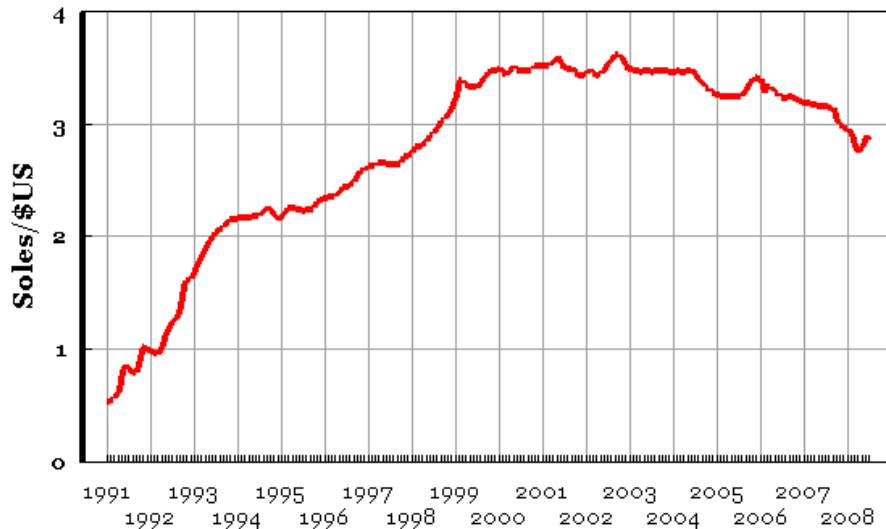
IFI terms:

- Interest rate U.S. dollar six-month LIBOR + interest rate swap + foreign exchange (FOREX) risk premium (3%)
- Loan term: 30 years, including 3 years' grace.

133. The magnitude of the interest rate premium (assumed here at 3 percent) to account for the foreign exchange risk is unclear.⁴⁶ If the project company assumes the exchange rate risk, the Ministry of Finance (MoF) might only take a 1 percent spread, but a sinking fund might well be established to cover exchange rate risk on debt service payments (thus having the same effect on financial returns to equity holders as a higher interest rate). If the MoF assumes the exchange rate risk, then the on-lending rate is a matter of negotiation (and the MoF's assessment of the FOREX risk),⁴⁷ since the higher the rate, the bigger is MoFs cushion to cover higher-than-expected depreciation of local currencies.

134. Figure 4.9 shows the exchange rate of the Nuevo Sol to the U.S. dollar since the currency reform of 1990. There are three distinct exchange rate regimes: in the early 1990s, annual depreciation rates of 60 percent, followed by a sharp reduction to around 8 percent annually in 1994–2000, and, since 2000, a gradual *appreciation* against the U.S. dollar.

Figure 4.9: Exchange Rate Variations



135. The firm energy bid price falls to US2.12¢/kWh (at late January 2009 interest rates), with a total energy cost of US4.11¢/kWh (Table 4.7).

⁴⁶ There will also likely be the cost of an interest rate swap (in which the variable LIBOR is converted to a fixed rate).

⁴⁷ In some countries, Ministries of Finance have set policies for on-lending rates for IFI loans. For example in Vietnam, the Ministry of Finance sets the on-lending rate at 50 percent of the long-term government bond yield for local currency on-lending, or the Organisation for Economic Co-operation and Development consensus commercial interest rate (CIRR) (which for US\$ of tenors of less than 8.5 years was 3.82 percent in December 2008) as a ceiling for FOREX on-lending.

Table 4.7: Blended IFI and Commercial Banks

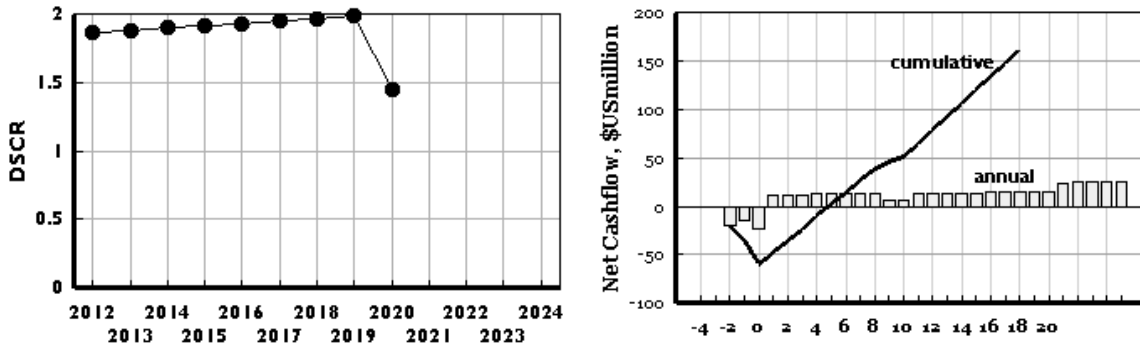
Conditions as of		Sept. 2007	Oct. 2008	End-Jan. 2009
Interest rates				
Six-month LIBOR	(%)	2.00%	3.75%	2.89%
Peruvian yield curve	(%)	6.00%	8.50%	7.50%
Revenue requirements				
Capacity charge	US\$m	5.30	5.30	5.30
Spot market sales	US\$m	9.78	9.78	9.78
Firm energy bid	US\$m	15.37	16.68	16.05
Total revenue requirements	US\$m	30.45	31.75	31.12
Firm energy bid price	US¢/kWh	2.03	2.20	2.12
Total financial price	US¢/kWh	4.02	4.19	4.11

Terms:

		IFI	Commercial Bank	Equity
Share		35%	35%	30%
Term (including grace)	(years)	30	10	
Grace	(years)	5	3	
Interest rate	(%)	LIBOR	YIELDC	
Plus	(%)	2.00%	2.00%	
FIRR target	(%)	17.5%		

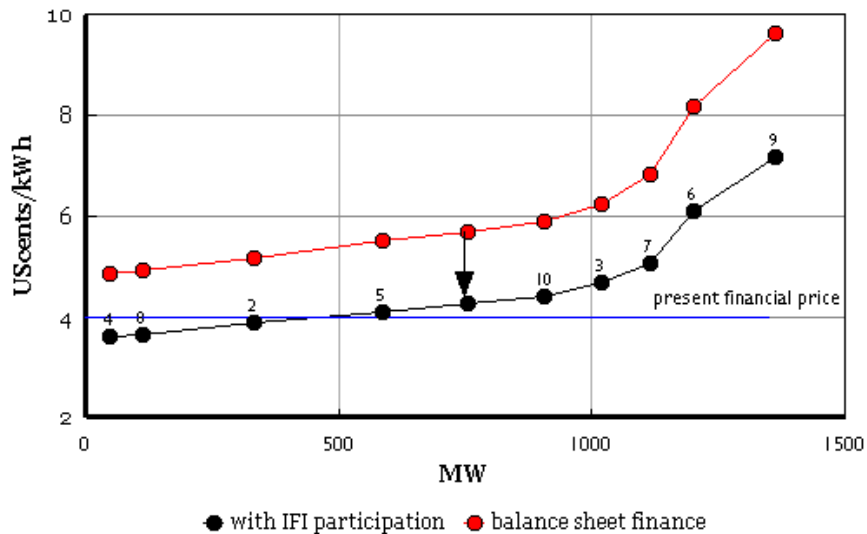
136. As shown in Figure 4.10, the minimum DSCR is a solid 1.4, which should provide the necessary comfort to the commercial banks.

Figure 4.10: DSCR, Typical Project: Blended IFI and Commercial Banks



137. The corresponding supply curve (based on our sample of hydro projects) is shown in Figure 4.11. Relative to commercial financing (see Figure 4.5), the supply curve shifts downward (that is, at any given energy price, more capacity is economic) by about US1.2¢/kWh to US2.0¢/kWh.⁴⁸

**Figure 4.11: Supply Curve Based on Sample Projects:
Balance Sheet Finance and Blended IFI + Commercial Banks**



138. Three of the projects would be enabled by IFI participation in the financing at the current average financial price (or around US4¢/kWh)—compared to no projects under normal commercial financing.⁴⁹

4.3.5 Public Sector Project with IFI Financing

139. A “classical” public sector project with IFI long term financing (Table 4.8) would have the following terms:

- Loan term: 30 years including 5 years’ grace
- Interest rate U.S. dollar LIBOR (4.2%) + FOREX risk premium (3%)
- Equity: 30 percent
- Return on public sector equity: 14 percent.

⁴⁸ In the case of the typical project, the difference is US5.52¢ - US4.11¢ = US1.41¢/kWh.

⁴⁹ However, as noted, what can be obtained at current prices is project specific, because the capacity charge component of the revenue requirement depends on the OSINERGMIN assessed payable capacity (*potencia remunerable*), and because most projects will have their own mix of regulated market energy prices, free market sales, and spot market sales.

Table 4.8: Public Sector Project with IFI Finance

Conditions as of		Sept. 2007	Oct. 2008	End-Jan. 2009
Interest rates				
Six-month LIBOR	(%)	2.00%	3.75%	2.89%
Peruvian yield curve	(%)	6.00%	8.50%	7.50%
Revenue requirements				
Firm energy bid	US\$m	5.29	5.29	5.29
Spot market sales (non-firm)	US\$m	9.78	9.78	9.78
Capacity charge	US\$m	10.37	12.53	11.46
Total revenue requirements	US\$m	25.44	27.60	26.53
Firm energy bid price	US¢/kWh	1.37	1.66	1.52
Total financial price	US¢/kWh	3.37	3.66	3.51
Terms				
Equity	(%)	30%		
Term	(years)	30	(including grace)	
Grace	(years)	5		
Interest rate: yield curve plus		2.0%		
FIRR target	(%)	14.0%		

140. The resulting firm energy price is a low US1.52¢/kWh—again the simple consequence of a very long loan tenor. If the FIRR were the same as for private sector projects (17.5 percent), the firm energy price would increase to US1.87¢/kWh, and from US3.51¢/kWh to US3.87¢/kWh for the *total* financial price.

4.3.6 Comparison of Scenarios

141. Table 4.9 summarizes the various financing scenarios for the three interest rate conditions. The ranking of prices remains unchanged no matter what the LIBOR and the Peruvian yield curve are: Project finance is the most expensive, and public sector financing the cheapest. Also, the scenarios including some sort of public financing (IFI long term or domestic development financing, which are not available at this stage) yield a very competitive bid price compared to current market conditions (see Table 6.3 for the results of recent energy auctions).

**Table 4.9: Comparison of Financing Scenarios:
Firm Energy Bid Price Required for Financial Viability**

Firm Energy Bid Price Based on Conditions as of:	Commercial	Project Finance	Development Bank Finance (Brazil)	IFI + Commercial Bank	Public Sector Project IFI Financed
September 2007	3.32	4.02	2.91	2.03	1.37
October 2008	3.66	4.32	2.91	2.20	1.66
January 2009	3.52	4.20	2.91	2.12	1.52
FIRR	17.5%	17.5%	17.5%	17.5%	14% (public sector)
Tenor	10	10	16	20 (average)	30
Interest rate	11.5	14.5	7.8%	9.35% (average)	7.2%

142. The corresponding total energy price (including capacity payments and spot market sales) are shown in Table 4.10, where it is noted that the interest rate conditions do not have an impact on the relative costs, the cheapest being the public sector option and the most expensive the project financing alternative.

Table 4.10: Total Financial Price to Meet Revenue Requirements

Total Financial Cost Based on Conditions as of:	Commercial	Project Finance	Development Bank Finance (Brazil)	Commercial + IFI	Public Sector
September 2007	5.32	6.01	4.91	4.02	3.37
October 2008	5.65	6.31	4.91	4.19	3.66
January 2009	5.52	6.19	4.91	4.11	3.51

143. The reputation of public sector projects in matters of construction cost overruns is not good. Critics will note that the cost advantage of the public sector project suggested above may well be eroded by cost increases. However, as shown in Table 4.11, a 30 percent cost overrun brings the required energy price to US4.42¢/kWh, less than the Development Bank model at US4.91¢/kWh, though slightly higher than the IFI blended model at US4.11¢/kWh. And even a 50 percent cost overrun in a public sector project would bring the required energy price to US5.03¢/kWh, still less than the commercial or project finance alternatives.

**Table 4.11: Impact of Project Capital Cost Increases
(January 2009 financing conditions)**

	Total Financial Energy Price US¢/kWh
Commercial Loan	5.52
Project Finance	6.19
IFI + Commercial	4.11
Development Bank (Brazil Model)	4.91
Public Sector	3.51
Public Sector, 30% Cost Overrun	4.42
Public Sector, 50% Cost Overrun	5.03

4.3.7 Sensitivity of Scenarios to Assumptions

144. The above analysis is subject to two main uncertainties, namely the construction cost, and the target FIRR. Table 4.12 shows the required energy price under combinations of FIRR and construction cost escalations for conventional balance sheet financing: a 20 percent increase in construction costs at the 17.5 percent FIRR raises the required energy price from US5.52¢/kWh to US6.48 ¢/kWh.

**Table 4.12: Sensitivity to Capital Costs and Target FIRR
for Typical Project, Balance Sheet Finance, Total Financial Price,
January 2009 Interest Rates, US¢/kWh**

Target FIRR (%)	Capital Costs		
	Baseline	+10%	+20%
10.0	4.06	4.42	4.77
12.5	4.53	4.93	5.33
15.0	5.01	5.45	5.89
17.5	5.52	6.00	6.48
20.0	6.03	6.56	7.10
22.5	6.53	7.12	7.70
25.0	7.03	7.67	8.30

145. The corresponding sensitivity analysis for blended private + IFI finance is shown in Table 4.13.

**Table 4.13: Sensitivity to Capital Costs and Target FIRR
for Blended IFI + Commercial Finance Terms, Total Financial Price,
January 2009 Interest Rates, US¢/kWh**

Target FIRR (%)	Capital Costs		
	Baseline	+10%	+20%
10.0	3.06	3.32	3.58
12.5	3.37	3.64	3.92
15.0	3.73	4.04	4.34
17.5	4.11	4.45	4.79
20.0	4.50	4.88	5.26
22.5	4.91	5.33	5.75
25.0	5.33	5.79	6.26

4.4 Impact of Carbon Finance on Financial Viability of Projects

146. Carbon finance is a potentially significant source of additional revenue. As shown in Table 4.14, for the case of balance sheet finance, revenue can increase by 17.1 percent at US\$15 per ton carbon dioxide (CO₂).

Table 4.14: Impact of Carbon Revenue on Electricity Price

Carbon Price	US\$/ton	5	10	15
Emission factor	kg/kWh	0.58	0.58	0.58
	US\$/kg	0.005	0.01	0.015
Price per kWh	US\$/kWh	0.0029	0.0058	0.0087
	US¢/kWh	0.29	0.58	0.87
Market price	US¢/kWh	5.52	5.52	5.52
Total price	US¢/kWh	5.81	6.10	6.39
Increase in price	—	5.0%	9.5%	13.6%

Note: Emission factor based on the 5.67 MW Caña Brava approved Clean Development Mechanism project. But this benefits from a simplified methodology applicable to projects only up to 15 MW and not available to large projects.

147. However, whether this potential revenue can actually be realized, and, more important, whether future carbon revenue would be seen as credible by lenders, is subject to a number of uncertainties:

- Carbon revenue may not be known at time of auction, and therefore is likely to be heavily discounted by lenders and bidders.
- Clean Development Mechanism (CDM) registration for large hydro projects will become increasingly difficult as additionality requirements are tightened. Projects must *demonstrate* that FIRR without Certified Emission Reduction (CER) sales are below customary hurdle rates, and that FIRR with CER sales are above the hurdle rate.
- Post-2012 CDM sales are still subject to high uncertainty, and post-2012 contract commitments, if obtainable at all, are subject to high discounts.

Currently there are three main carbon markets:

- Kyoto credits, in particular CERs. The average CDM price in 2007 was US\$16/ton CO₂ (Table 4.15).
- European Union (EU) allowances (emission permits under the EU Emission Trading System, trading on the European Climate Exchange [ECX]). The average 2007 price was US\$25/tonCO₂ (Table 4.16).
- Voluntary credits (VERs): the main voluntary market is the Chicago Climate Exchange (CCX) where carbon trades at US\$6. Retail carbon (to offset holiday travel, for example) can be over 20 euros.

Table 4.15: The Clean Development Mechanism Market

	2006		2007	
	Volume (MtCO ₂ e)	Value (MUSS)	Volume (MtCO ₂ e)	Value (MUSS)
Compliance	597	6,466	832	13,376
<i>of which</i>				
Primary CDM	537	5,804	551	7,426
Secondary CDM	25	445	240	5,451
JI	16	141	41	499
other	19	76	na	na
Voluntary market	14	70	42	265
TOTAL	611	6,536	874	13,641

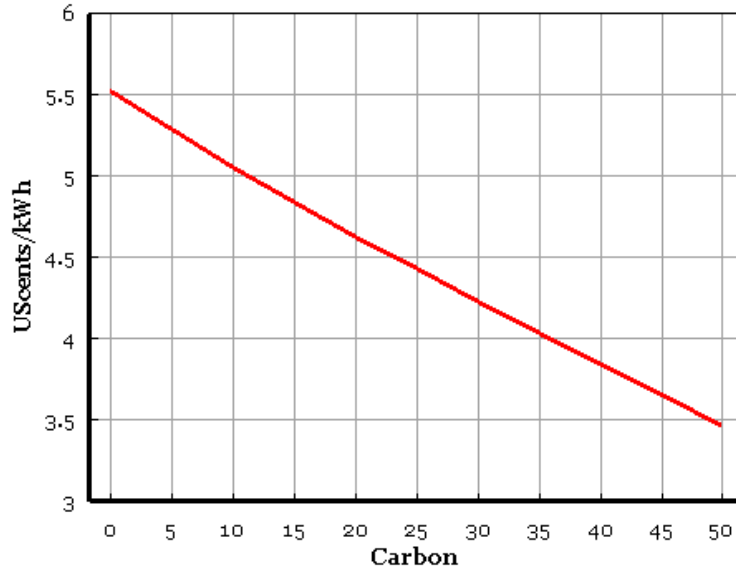
Table 4.16: The EU Market

	2006		2007			
	Volume (MtCO ₂ e)	Value (MUSS)	Volume (MtCO ₂ e)	y-to-y growth rate	Value (MUSS)	y-to-y growth rate
EU ETS	1,104	24,436	2,061	87%	50,097	105%
New South Wales	20	225	25	26%	224	-1%
Chicago Climate Exchange	10	38	23	124%	72	90%
UK ETS	na	Na				
TOTAL	1,134	24,699	2,109	86%	50,394	104%

Source: For Tables 4.15 and 4.16: "State and Trends of the Carbon Market," World Bank, 2008.

148. The impact of carbon revenue on the required energy price is shown in Figure 4.12: at US\$15/tonCO₂, bid price decreases from US5.5¢/kWh to US4.8¢/kWh, and to US4.25¢/kWh at US\$30/tonCO₂. However, whether such carbon revenues would be reflected in any advance bidding for firm energy in an auction seems most unlikely, given the uncertainties of the CDM process and the increasing difficulties in demonstrating additionality.

Figure 4.12: Impact of Carbon Finance on Required Total Financial Price, Balance Sheet Finance, January 2009 Interest Rates, FIRR 17.5 Percent



4.5 Financing Hydropower Projects: Risks and Mitigating the Risks

149. Even before the recent global financial crisis, hydro projects had always been the most difficult type of power sector projects to finance. Capital intensive, long construction times, unique site-specific risks poorly understood by bankers and lawyers, and subject to the unremitting attention of nongovernmental organizations (NGOs) and the press regarding potential environmental and social impacts, are all features that make potential lenders very nervous. That many of these issues do not actually apply to medium-size hydro projects of the type that have been examined in this report is small comfort: even small hydro projects of 5 MW to 20 MW face the skepticism of Peruvian lenders.

150. Successful financing of hydro projects requires a demonstration that the following major risks can be successfully mitigated:

- Price risk (less-than-expected revenue where some or all of the off-take is at market prices)
- Completion risk (including risks of delay due to litigation during construction, cost overruns, and to geotechnical problems or water rights disputes)
- Hydrology risk (less-than-expected electricity generation due to lack of water)
- Operational risk (inability to operate because of mechanical failures or operational problems at the plant)
- Off-take risk (failure of the buyer to take power due to reasons of dispatch, transmission congestion, or transmission line failure).

151. These risks were discussed with the major Peruvian banks, and their perceptions about the importance of each risk are summarized below.

4.5.1 Price Risk

152. Worldwide, a Power Purchase Agreement (PPA) for at least the duration of debt service repayments, with a creditworthy buyer, and with predictable tariffs, is a basic requirement. A signed PPA is an absolute prerequisite for financial closure of project financing. However, the Peruvian banks do not see price risk as a major problem for Peruvian hydro projects. The pricing mechanism is well understood, and the risk is easily mitigated by requirements for a certain portion of output to be covered by a PPA with large users or distribution companies. The creditworthiness of the participants in the Peruvian market is not an issue. The PPA coverage requirement varies across the banks (and across generation technologies). One bank noted different requirements for thermal and hydro projects: thermal projects require 75 to 100 percent PPA coverage, while hydro project coverage might be 50 percent or even zero—a reflection of the very high probability of hydro projects being dispatched, and receiving the system marginal price on the spot market.

4.5.2 Completion Risk

153. This is the dominant concern of lenders, and the most difficult to mitigate in the case of hydro projects. The banks see the involvement of reputable Engineering, Procurement, and Construction (EPCs) as the appropriate mitigation for completion risk. But the difficulty is that the completion guarantees as may be provided by EPCs come at a high cost; indeed, even aside from guarantees, the participation of the EPC is costly to the developer. Banks are particularly averse to tunneling risk.

154. Even when large corporate sponsors set up special-purpose entities (as in the case of the Plantanal 220-MW project that is underway without an EPC, instead using an in-house engineering arm), banks look to the sponsors at least to completion.⁵⁰

155. The lack of certainty in water rights was cited as one of the completion issues, arguably more of a concern than geotechnical or engineering risk. Several projects have been delayed by late interventions by NGOs and local communities disputing the decisions made by the Central Government. There seemed general agreement that a new Water Rights Act is required, which needs to clarify the jurisdiction of the various entities of government.

4.5.3 Hydrology Risk

156. Neither the banks (nor the developers) seemed concerned about hydrology risk. Yet, the one bank that mentioned this risk had not in fact reviewed any greenfield hydro sites, and stated that it would engage a local consultant to conduct a review of the hydrology assumptions. Another bank noted that if an otherwise sound small hydro

⁵⁰ This project has been described as “project financing with recourse to sponsors”—but that recourse to sponsors really makes this a normal commercial financing, not a true non-recourse financing.

project ran into financial difficulties consequent to cash flow problems attributable to several consecutive dry years, then such a project could simply be refinanced.

157. In international practice, lenders may require a debt service escrow (which must be funded before dividend payments to equity holders), sufficient for 3 to 12 months of debt service obligations.

4.5.4 Operational Risk

158. This risk is rightly seen by the banks as low. For thermal projects, manufacturers of gas turbines offer very high availability guarantees, and hydro turbines and generators are perceived correctly as being of high reliability.⁵¹ In international practice, where significant major maintenance expenditures are anticipated (turbine runner replacements where there are high and abrasive sediment loads), lenders may require a major maintenance escrow fund.

4.5.5 Off-take Risk

159. Off-take risk for hydro projects is seen as small. There are two potential sources of off-take risk: the failure to be dispatched, and the failure of the buyer to take the power for reasons of transmission line failure. As noted, failure of a hydro project to be dispatched is most unlikely.

160. These perceptions of risk are of course not unique to Peru. The worldwide experience of the IFIs is that these risks can in fact be managed satisfactorily in the case of medium-size run-of-river or daily peaking hydro projects that require only very small reservoirs, and pose neither major rehabilitation and resettlement problems nor the geotechnical problems associated with very large dams. The unique problems associated with most of the well-publicized mega projects (Three Gorges in China, Sardar Sarovar in India, and some of the Brazilian projects of reservoirs with very large surface areas) are simply not relevant.

4.6 Impact of the Global Financial Crisis on Financing Hydropower Projects

161. As noted in the previous section, financing hydropower projects is always difficult, given the risks described and the long-term nature of the projects. The impact of the current global financial crisis on the prospects for financing plants in Peru is unclear, particularly given the uncertainty about the duration of the global recession and

⁵¹ Some concern was expressed about the reliability of Chinese equipment, mainly in connection with the way in which Chinese equipment was being offered in Peru. It appears that Chinese suppliers appearing in Peru are mainly integrators rather than original equipment manufacturers, taking components from various sources, which raises some doubts about the quality of manufacturer's warranties being offered. However, the concerns about Chinese equipment reliability lacked any specificity. Chinese turbine-generator equipment is being offered in Peru at prices that are typically 70 percent of the established European suppliers such as Alstom. The lower prices come at the price of significant efficiency penalties (for example, 89 percent for Chinese turbines compared to 93 percent for Alstom).

how long it will take for bank liquidity to be restored. Certainly, the indications as of the time of writing (January 2009) is that restoration of banking sector balance sheets and attaining new reserve requirements will likely extend well into 2010. The present volatility in global markets makes reliable predictions difficult.

162. In the first nine months of 2008, inflation in Peru was well above the Central Bank target of 2 percent. Interest rates rose in 2008 (see yield curves in Figure 4.1), and the Soles interbank interest rate is currently at its seven-year high, at 6.5 percent. But most expect a decrease in 2009 as inflationary pressures subside.

163. However, with the sharp drop in oil prices and food imports in the last quarter, inflation and interest rates in 2009 may well decline. Unfortunately, the price of Peru's main mining exports have also fallen (the current copper price is US\$3,170/ton,⁵² down from its peak of US\$8,940/ton in July 2008 (though that record price was in part a consequence of a mining strike).⁵³

164. Thus, Peru's gross domestic product (GDP) for 2009 is expected to fall from 9.5 percent to around 4 percent, still substantially above expected Organisation for Economic Co-operation and Development (OECD) growth rates. But as elsewhere, the Government has announced a stimulus package, and to provide more liquidity for lenders, the Central Bank recently reduced reserve requirements in local and foreign currency (it cut the minimum legal reserve requirement to 7.5 percent of deposits from 9 percent and the foreign currency requirement to 30 percent from 35 percent).

165. Even 18 months ago, when the liquidity position of the Peruvian Banks was relatively good, lending requirements were very conservative—and unlikely to become *less* conservative in the current environment of high volatility. In 2009, commercial financing at the long tenors required for hydro projects will be very difficult. The hydro projects that will be the most difficult to finance in Peru in the current climate are likely the small hydro projects promoted by relatively financially weak small companies, and some projects proposed by mining companies (to the extent that the sharp downturn in commodity prices may have impacted mining company cash flows).

166. In short, the prospects for commercial financing of hydro projects that require long tenors is poor, and the prospects for non-recourse hydropower deals even poorer. This suggests that it would be unlikely for new projects to be financed in the short term unless there is IFI participation.

⁵² London Metal Exchange, January 12, 2009, Grade-A cash buyer.

⁵³ Prices of copper, zinc, lead, silver, and natural gas, which account for 60 percent of Peru's export revenue, have all halved since early July 2008.

4.7 Conclusions on Financial Viability of Hydropower Development in Peru

167. The most striking conclusions to be drawn from this chapter's analysis are that:

1. Financial energy prices show great variation across projects. All other things being equal, the total financial price (that is, the average price necessary to meet the revenue requirements for meeting a target equity return, operating costs, and debt service) varies among the project sample from US4.8¢/kWh to US9.6¢/kWh (for commercial finance, January 2009 interest rates).
2. Financial energy prices also show great variation by financing structure. For the typical project, and under current interest rate conditions, the total financial price varies from a high of US6.19¢/kWh for a project financing to a low of US3.51¢/kWh for a public sector project (for January 2009). Even when both of these extreme cases are discarded, the range of financial price between a normal commercial finance deal (a balance-sheet financing of the kind illustrated by the ongoing El Plantanal project) and one with IFI participation is from US5.52¢/kWh to US4.11¢/kWh, respectively.
3. It can be argued that a good hydropower plant, such as the typical project, could, on occasion, be marginally competitive if compared to the results of the latest energy auctions conducted in Peru. However, this would be possible only for projects that have strong corporate backing and access to commercial (corporate sheet) financing.

168. At the time of writing, global financial markets are in disarray, and interest rates and liquidity positions are changing rapidly. A normal situation for financing of new projects is not likely to be achieved until the toxic asset problems of major banks are resolved, and the global economy resumes economic growth, something that is not likely to occur until late 2009 or 2010, or even later.

169. Nevertheless, the above discussion of financing alternatives permits a number of conclusions that apply to whatever the market conditions may be:

- For long-lived, capital-intensive investment, longer loan tenors are vital to bring down financial energy prices. Thus, the IFIs could have an important role to play in bringing down the costs of financing hydro projects (by around 25 percent); even when blended with shorter-term commercial loans, the general result of longer tenors is a significant decrease in the average financial price. As one might expect, this advantage of IFI participation holds regardless of the prevailing interest rates—whatever the rate, a project with IFI involvement can offer a lower financial price than those limited to commercial or project finance.
- Project financing for larger hydro projects will be very difficult. Even under relatively normal market conditions, the Peruvian commercial banks are averse to carrying completion risk.

- Carbon revenues for larger hydro projects can make a significant difference, but are currently subject to high uncertainty for post-2012 CDM carbon sales, and carry high discounts if available at all. Additionality requirements are being tightened.

170. It is clear that under current generation market conditions, only exceptional projects can be financed on the basis of conventional FIRR benchmarks. As shown in the case of El Plantanal, some hydro projects have been implemented by industrial consortiums as a hedge against future supply disruptions, rather than as profitable ventures to supply the local market as a whole.

171. By late 2008, the generally pessimistic perception about the viability of hydro projects lessened somewhat in the wake of unusually high spot market conditions (see Figure 4.3), with prices substantially above the regulated market price for much longer periods than has been the case in recent years. Since hydro projects are assured of dispatch under the current arrangements, these price increases have been encouraging to developers. Unfortunately, this occurred just as the financial crisis struck, and the past six months have seen few signs that projects are actually reaching financial closure, though interest has undoubtedly increased.

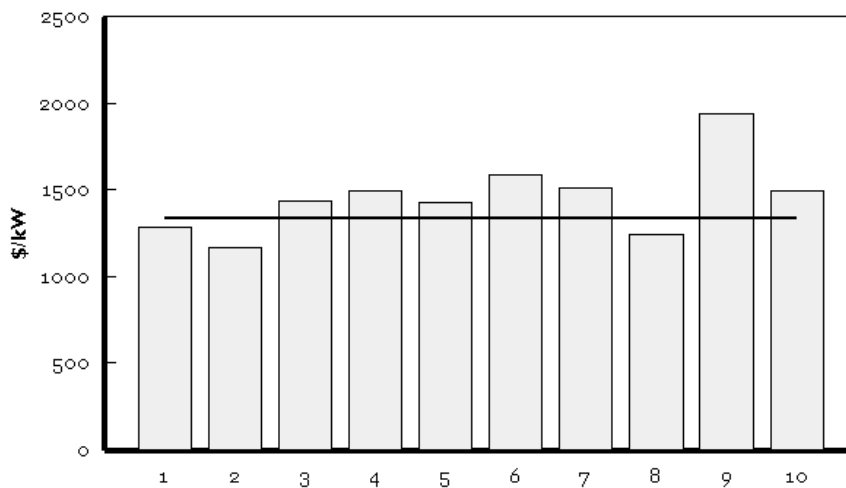
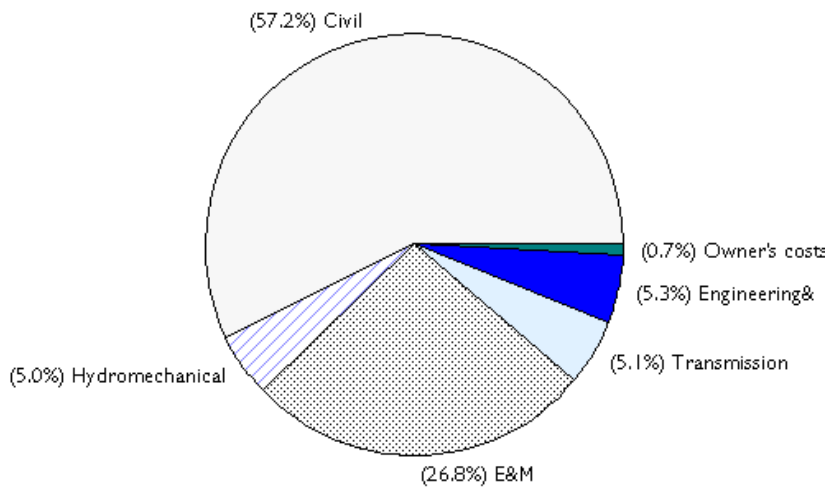
Box 4.2: A Typical Project

For a number of sample calculations presented in this report, notably for the assessment of alternative financing options, it is useful to define a “typical project” that serves as a proxy for the entire sample.

This typical project is defined as having the average characteristics of the seven best projects, namely:

- Capacity: 146 MW
- Plant factor: 0.6
- Capital cost: US\$1,346/kW
- Economic Rate of Return at US\$4.4/mmBTU = 14.7 percent
- Economic production cost = US4.34¢/kWh.

Breakdown of Costs



5. ENABLING FRAMEWORK: LICENSING OF HYDROPOWER INVESTMENTS AND WATER RIGHTS MANAGEMENT

172. Peru's legal and regulatory framework is based on the Electric Concessions Law (Ley de Concesiones Eléctricas, LEC) and its regulations, which established a system of authorizations and temporary and definitive concessions, modified several times over the years. This chapter reviews the process of concessions as it is applied to hydropower plants, the procedures for obtaining water rights and rights of way, and the current procedures for the preparation of environmental and social impact studies.

5.1 Concessions for Hydropower Plants

173. A concession is needed for the use of public property (water and potentially land) or the need to expropriate privately owned land for an extended period of time. When providing electricity to the grid, hydropower plants fulfill a public service that also requires a concession. Current legislation establishes two types of concessions for hydropower projects: temporary and definitive concessions.

174. Details on the procedures and requirements for temporary and definitive concessions are presented in Annex 4.

5.1.1 Temporary Concessions

175. A temporary concession allows for the use of public property and the right to impose temporary rights of way. In return, the concessionaire is obliged to fulfill feasibility studies for generation and transmission. A temporary concession does not give exclusivity over the relevant area and can be granted to more than one petitioner (the same applies to the license for water use to conduct studies).

176. A temporary concession⁵⁴ can be granted for up to two years and can be renewed only once for two more consecutive years. The extension of temporary concessions are justified only on the grounds of force majeure, that is, that because of reasons beyond the control of the project developer, an extension is needed for the completion of studies.

5.1.2 Definitive Concessions

177. Following Executive Decree 1002,⁵⁵ all electric energy generation plants using hydro resources with an installed capacity of 500 kilowatts (kW) and above need to have

⁵⁴ Temporary concessions are regulated by article 23 of the LEC, Regulations articles 30–33, and the Unified Text for Administrative Procedures CEO2 Annex 1.

⁵⁵ Decreto Legislativo No. 1002, *Decreto Legislativo de Promoción de la Inversión para la Generación de Electricidad con el Uso de Energías Renovables, El Peruano*, May 2, 2008.

been granted a definitive concession.⁵⁶ These concessions are given for an indefinite period and allow for rights of way to be imposed by the State. Definitive concessions allow for the use of public property and the right to obtain the imposition of rights of way (that can be permanent and by expropriation if necessary) for the construction and running of electricity-generating stations and related constructions such as transmission lines.

178. A definitive concession can either expire (when some of the contract's clauses are not fulfilled, required maintenance obligations are not carried out, or the station has not been operating for 876 hours per calendar year), or can be relinquished by the concessionaire.

179. The current system for definitive concessions has a few shortcomings that merit review:

- Definitive concessions can be granted at a stage when a project has yet to comply with many conditions necessary for its actual implementation, especially financing. Since a definitive concession grants exclusive rights for a project site, this condition often blocks the development of a project since rights are given/granted to groups that are not ready to proceed with construction and/or are financially weak. Also, since the granting of a concession implies the end of any competition for the project, it would be more convenient to award it after a competitive process, say an auction, for the project is held. The latter point is particularly relevant for large projects where it is of national interest that they are developed in the most efficient manner.
- Definitive concessions are indefinite in time, that is, they have no termination date. This policy merits revision since it is not consistent with the common practice (for example, build, own, operate, transfer [BOOT] arrangements) in power generation.

5.1.3 Other Requirements at the Local Level

180. In addition to temporary and definitive concessions, a plant also needs a generation and transmission concession (to be able to operate within the power system) and other local permits, such as:

- Planning and building permission, to allow construction on land
- Permits needed at different stages for the plant's different sections (tunnels, turbines, and so forth)
- Permits involving the facilities and personnel such as working permits, and so forth.

⁵⁶ Definitive concessions are set up in the LEC articles 3, 6, 22, 25, and 28; in its Regulations articles 37–43, 53, and 54; in the Unified Text for Administrative Procedures (TUPA) CEO1 Annex 1; and in Executive Decree 1002 (for Definitive Concessions to Generate Electricity Using Renewable Energies).

5.2 Water Rights

181. Procedures for obtaining water rights are presented in Annex 4. Table 5.1 shows the complex link between project concessions and water rights at different stages of a project. These processes are undergoing changes, however, due to the creation of the National Water Authority, which will assume many of the responsibilities of the National Institute for Natural Resources (*Instituto Nacional de Recursos Naturales*, INRENA).

Table 5.1: Concessions and Water Licensing Processes

Project Stage	Concession Process	Water Licensing Process
Studies	Temporary Concession: Granted by Ministry of Energy and Mines (MEM) for a maximum of four years. Does not provide exclusive rights, but the authorization to study the project.	Authorization to carry out studies: It is not exclusive, but it is necessary to acquire a temporary concession. INRENA approves such studies.
Prior to Construction	Definitive Concession: Granted by MEM. Provides exclusive rights for the construction and operation of the hydropower plant. Prior to granting the Definitive Concession, an Environmental Impact Study (EIS) and a River Basin Management Plan need to be approved as a prerequisite. Once the Definitive Concession has been granted, the project can apply for the Certificate of Nonexistence of Archaeological Remains (CIRA), necessary to start construction.	At this stage, INRENA must have reviewed and given its opinion on the EIS presented by the project, and should have also approved the final studies for the project. Water-use license before construction starts: INRENA has to grant a water-use license for power generation before construction starts. Water volumes and use patterns need to be specified. Must obtain the Users Association's opinion beforehand, through consulting the affected Water Technical Administration.
Construction Phase	Other permits at the local level such as planning and building permission, security, and safety-at-work regulations for personnel.	

182. A new Peruvian Water Law was passed by Congress on March 13, 2009,⁵⁷ since the old Water Law⁵⁸ was considered obsolete. However, for the past few years, new laws⁵⁹ have tried to simplify and clarify procedures, and centralize water regulation, focusing on the need to fight against the existing discretion and conflicts of interest in this area and to ensure that civil servants are technically trained and familiar with these

⁵⁷ Law 393478, *Ley de Recursos Hídricos*.

⁵⁸ Decreto Ley 17752, *Ley General de Aguas*, *El Peruano*, July 24, 1969.

⁵⁹ Decreto Supremo 005-2006-AG, *Establecen disposiciones para el cumplimiento del requisito establecido en el literal b) del artículo 25 de la Ley de Concesiones Eléctricas, sobre licencia de uso de agua para fines de generación de energía hidroeléctrica*, *El Peruano*, Febrero 10, 2006; Decreto Supremo 078-2006-AG, *Dictan disposiciones en materia de aguas sobre dependencia de las Administraciones técnicas de los Distritos de Riego y para uniformizar procedimientos administrativos a nivel nacional*, *El Peruano* 28 Diciembre 2006; Decreto Legislativo 1081, *Decreto Legislativo que crea el sistema nacional de recursos hídricos*, *El Peruano* 28 Junio 2008.

complex issues. Important pieces of legislation have been enacted without proper consensus building thanks to the “special legislative powers” granted to the Ministry of Agriculture to mitigate any potential negative impacts on farmers caused by the free trade agreement with the United States.

183. While the new Water Law (Box 5.1) brings important changes (yet to be regulated):

- Water use licenses will now be issued by the National Water Authority (article 47 of Law 393478).
- Multisector commissions play an important role in the National Water Authority’s (*Autoridad Nacional del Agua*, ANA’s) structure. They encompass representatives of sectors such as housing, energy, and agriculture.
- The tariff is used to allow each sector to operate. However, in addition to this tariff, the law creates what it calls Economic Retribution for Water Use, which has to be paid by all users, and allows for the maintenance of the river basins management system.

Box 5.1: The New Water Law

- The new water law declares water a public good, and maintains some aspects of the old water law, such as nontransferable water rights, the possibility of revoking water rights if the tariff is not paid, and the old order of priorities in its use.
- It is up-to-date with current changes in water legislation, such as the new National Water Authority (ANA), which will now be dependent on the Ministry for the Environment. Tariffs are better defined, and users have wider participation in the ANA through river basin councils and water users associations.
- The project creates a constitutive registration process, which has proved to be, in other countries such as Chile, difficult to reconcile with native and traditional rights.
- The proposed water royalty (*Canon Hidrico*) was eliminated by Congress in its March 1, 2009, session and never restored.
- Two main challenges are budget constraints to enforce such sophisticated water management schemes and capacity limitations (although the institutional framework at the local level has been simplified considerably).

184. Executive Decree 1081, dated June 2008, creates the National System of Water Resources, an integrated and multisector organ that includes the new National Water Authority within the Ministry for the Environment under which water licenses are given (in fact, the ANA is but the old Water Resources Directorate, dependent on INRENA). It also creates the Basin Councils (*Consejos de Cuenca*), interdisciplinary organs depending on the ANA.

185. However, key issues have yet to be addressed, such as the lack of adequate representation of all the interested sectors, including indigenous peoples and others in

local communities, and proper mechanisms to address frequent conflicts regarding water (especially its quality and volume).⁶⁰ Also, irrespective of whether there is a canon or water royalty established by law, stakeholders agree that this is not being implemented in hydropower. The absence of an effective benefit sharing mechanism is particularly important for the following reasons:

- Such mechanism would help align the interests of affected groups and project developers, creating a vehicle of common interest. In its absence, affected communities have limited or no incentive to support a project since they perceive that they would not be sharing its benefits.
- It would help develop local communities and strengthen the relationship among the State, the community, and the project.

5.3 Current Procedures for Environmental and Social Impact Assessments

186. Current legislation establishes two types of Environmental Studies for hydropower plants, according to the installed capacity: an Environmental Impact Study (*Estudio de Impacto Ambiental*, EIS) for plants above 20 megawatts (MW) and an Environmental Impact Declaration (*Declaración de Impacto Ambiental*, DIA) for those plants with a capacity between 500 kilowatts (kW) and 20 MW.⁶¹ In addition, environmental studies presented by a hydroelectric plant must include a River Basin Management Plan (*Enfoque de Manejo de Cuenca*).

187. While environmental assessments for power projects have been prepared since the mid-1990s, there is still a set of problems to overcome together with the inherent conflict of interest in the Ministry of Energy and Mines' (MEM's) role as both promoter and regulator of projects:

- The main obstacle to the correct implementation of the environmental studies is the lack of useful guidelines for their execution, weak supervision by government agencies, and no independent assessment of social and environmental impacts. Budget constraints in the MEM and lack of expertise to monitor studies are the main reasons.
- Chapter 2 makes reference to the less-than-satisfactory quality of the studies being done. The quality of the studies and the process itself could benefit from strengthening these guidelines using valuable international experience, such as the World Bank safeguards, and others. There is no independent and consistent review of all studies by an audit body at the MEM.
- Although Ministerial Order 535-2004-MEM/DM establishes the requirements guaranteeing the involvement of those affected in the environmental studies,

⁶⁰ An innovative and interesting system to solve water controversies is the participative monitoring of water. A prototype of such a system was used in Cajamarca (*Oficina del Asesor en Cumplimiento [CAO] Monitoreo Participativo del Agua. Guía para Prevenir y Manejar el Conflicto*, CAO 2008.)

⁶¹ Both regulated in R.D. 008-97-EM (Maximum Emission Limits Permitted for Electricity Activities) and D.S. 029-94-EM (Rules for Environmental Protection in Electricity Activities).

through public hearings, it is rarely executed satisfactorily. Its ambiguity makes it difficult to enforce, and the responsibility to guarantee its implementation rests with the General Directorate for Energy Environmental Matters (Dirección General de Asuntos Ambientales Energeticos, DGAAE). This shortcoming is particularly important when dealing with projects in the Amazon basins that are likely to affect indigenous people.

- There is no regular or proper channel of communication throughout the life of the project among the State, private developers, and affected communities.
- The informality surrounding ownership titles, the weakness of communal institutions, and the lack of alternatives to economic compensation, traditional in expropriation cases, can considerably delay a project's construction period.

5.3.1 Environmental Impact Study

188. As detailed in Annex 4, when a power plant has an installed capacity of more than 20 MW, an Environmental Impact Study (EIS) is needed. The study has to identify and evaluate all possible direct and indirect environmental impacts, including biological, physical, cultural, and socioeconomic effects. Guidelines are available at the MEM if required, as mentioned above.

189. It has to include an Environmental Management Plan (*Plan de Manejo Ambiental*, PMA), which will try to minimize, avoid, or compensate for those negative effects and any potential benefit, especially measures designed to protect local communities.

5.3.2 River Basin Management Plan (*Planes de Manejo de Cuenca*)

190. Part of the EIS for a hydroelectricity generation project, the management plan establishes guidelines and measures for the management and administration of hydrology and water resources.

5.4 Rights of Way

191. A right of way or an easement is a privilege to pass over the land of another, whereby the holder of the easement acquires only a reasonable and usual enjoyment of the property, and the owner of the land retains the benefits and privileges of ownership consistent with the easement.

192. For definitive concessions, the rights of way are imposed by the State and the landowner cannot refuse their imposition, which is done either by giving compensation or by renting the land on which the right of way will be imposed.

193. Rights of way can be temporary or permanent, and the concessionaire needs to apply to the General Directorate for Electricity (*Dirección General de Electricidad*, DGE) for their imposition (since it is the State that will enforce the right of way) with a descriptive and explanatory statement. They need to be specified when applying for a temporary and definitive concession.

5.4.1 Current Issues and Concerns

- There are irregularities regarding land registration and the ability to impose the right of way. One of the problems is the existing dual system that distinguishes between ownership (propiedad) and possession (posesión). If it is the latter, or the land belongs to a community, it becomes more difficult to impose the right of way.⁶²
- Problems in the registration of rights of way and properties affected often delay the process.⁶³
- Overexpectations are sometimes not properly managed.
- Rivalries between communities are often ignored, thus increasing the risk of conflicts among different affected groups.
- Workshops and public hearings are often not well organized, taking place in venues with inadequate amenities, such as proper translation services, and not taking into account the individual characteristics of each community. It is necessary to promote legitimacy by granting adequate participation, access to information, and deliberation.
- A legal framework to enable an effective assessment of a project's social impact and a social agreement is missing, including with indigenous people and others in affected local communities. The hydroelectric sector could benefit from a permanent information channel, like some other energy sectors already have in place. This social assessment plan would have a defined scope, setting up the required documentation and studies, the approval process, time frame and deadlines, and agreements reached on implementation and monitoring. It would be independently carried on but integrated in the EIS.

194. Because of its sensitivity and the importance in such cases of having a good relationship from the beginning, the imposition of rights of way and expropriations, and available mechanisms to allow dialogue and information sharing, need to receive proper attention during the project's life, and a thorough and systematic social analysis must be included in any environmental studies.

5.5 Certification of Nonexistence of Archeological Remains

195. It is no longer necessary to have had an approved Certification of Nonexistence of Archaeological Remains (*Certificado de Inexistencia de Restos Arqueológicos*, CIRA) to obtain a definitive concession,⁶⁴ although project sponsors and developers prefer to send their applications during the studies phase, which need to be submitted to the National Culture Institute (*Instituto Nacional de Cultura*, INC). It is required prior to construction.

⁶² The setting up of quarries needed for construction, for example, has frequently been very difficult.

⁶³ For example, rights of way can only be registered electronically and filed with the definitive concession when the lands have not been registered yet. Otherwise, they will appear in the Land Registry but not in the concession's electronic file, which can slow the compensation process.

⁶⁴ Decreto Legislativo N° 1003, *Decreto Legislativo que Agiliza Tramites para la Ejecución de Obras Publicas*, *El Peruano*, May 2, 2008.

196. Regulations are very weak in this area, and there are no measures to guarantee the follow-up of the protective measures, requisites are not specified, and there are frequent delays.

5.6 Legal Framework for Foreign Investments in Power Generation

197. The Government of Peru recently enacted a new arbitration law⁶⁵ aimed at promoting both national and international arbitration and facilitating the execution of foreign court rulings.

198. There is no special regime for foreign investments in this sector (contrary to the situation in other areas, where foreign investments get special treatment: the contract acquires the status of a law, thus achieving better guarantees, following article 62 of the Peruvian Constitution, 1357 of the Civil Code, and Law N° 26438). However, power generation contracts tend to be long-term investments and would benefit greatly from the legal and fiscal stability and transparency clauses and general legal guarantees such as the ones referred to above.

199. Although not part of the Energy Charter Treaty that specifically sets up foreign investment arbitrations in the sector, together with general guidelines and scope for such contracts, Peru does have a series of Bilateral Investment Treaties (BIT)⁶⁶ and recently concluded a series of agreements with Brazil regarding the generation of energy using hydropower in Peru.

200. In addition, Peru is a member of the International Centre for Settlement of Investment Disputes (ICSID), and currently has one pending investment arbitration regarding tariffs and transmission (ARB 06/13 Aguaytia LLC vs. Republic of Peru), registered on July 18, 2006, and had a previous one (Duke Energy International Peru Investments No 1, Ltd. vs. Republic of Peru). It is expected that international tribunals such as the ICSID will gain more relevance in water matters, where some decisions have already become landmark cases.

5.7 Conclusions and Recommendations

201. The complex and multisector nature of hydropower translates into the participation of a large number of players in the process, several of which have insufficient technical capacities. It is perceived that the lack of transparency of the process, and frequent changes brought about by reforms in the law make it unpredictable and excessively long. In particular, the legal framework regulating water rights and rights of way has major voids and fails to satisfactorily address issues and conflicts, including with indigenous peoples and others in local communities, that often arise in the use of water and become a barrier to the development of hydropower projects.

⁶⁵ Decreto Legislativo N° 1071 *Decreto Legislativo que Norma el Arbitraje, El Peruano*, June 27, 2008.

⁶⁶ Thirty are currently registered with the ICSID.

202. While the system of temporary and definitive concessions for hydropower projects has been useful in supporting the enabling environment for project preparation, there is room for improvement in making it more efficient. Two important areas that merit review are: (a) the need to award definitive concessions at a more advanced level of preparation, preferably, after a competitive process is held and projects have secured a Power Purchase Agreement through either an auction for energy sales or competing for a specific project. In both cases, projects should have obtained an environmental license prior to the auction. Such approach would help avoid early exclusivity rights that could hamper competition and, consequently, a more efficient process; and (b) the need to revise the indefinite, open-ended nature of definitive concessions with a view to introduce a termination or extension under conditions to be agreed upon. These two points are of great importance when dealing with large hydropower projects, such as those being prepared with plans to export electricity to Brazil, since incorporating competition into a project that has been prepared by a single group has the potential of yielding considerable economic benefits to the country.⁶⁷

203. While the current administration has embarked on a new restructuring of the sector, it is in the interest of the hydropower business to restore the clarity of the processes for water rights. Two issues of special importance for hydropower are:

- The establishment of an effective benefit sharing mechanism would help align the interests of affected communities and project developers and, therefore, help develop local communities and strengthen relationships among the State, the community, and the project.
- A legal framework that recognizes that the use of hydropower is, in most cases, nonconsumptive.

204. While environmental assessments for power projects have been prepared since the mid-1990s, there is still a set of problems to overcome together with the inherent conflict of interest in the MEM's role as both promoter and regulator of projects. Key problems include the quality of environmental studies, weak consultation processes including with indigenous people and others in affected communities, and the absence of a proper framework to address social issues. Specific recommendations to improve EISs and/or the overall process of environmental and social assessment are:

- Establish an independent and objective auditing system, whose members would have enough technical expertise to allow for a correct evaluation of the submitted study by the MEM.
- An adequate budget appropriation for the monitoring of the process.
- Establish clear and proper minimum requirements for the studies, in order to ensure uniformity in quality and content. To this end, the MEM should take the initiative in establishing standardized terms of reference.

⁶⁷ Brazil's recent experience in auctioning the Rio Madeira projects (two large hydropower projects adding 6,500 MW), that had been prepared by a single consortium, yielded a cost reduction of around 30 percent. A discussion of this experience is presented in Chapter 6.

- Seek the proper coordination of studies taking place in the same area or affecting the same river basin.
- Work toward formulating a social agreement, through a more open and legitimate consultation process, seeking the participation of local NGOs and mechanisms to align the interests of all stakeholders.
- Provide training on best practices for environmental and social safeguards to all stakeholders.

6. ENABLING FRAMEWORK: REGULATORY SYSTEM AND AUCTIONS

205. This chapter presents an overview of the Peruvian electricity sector, focusing on its regulatory framework and, in particular, its pricing system. It also discusses power generation and natural gas policies, the power supply auction system, investment requirements, and the roles of the private and public sectors in meeting the country's future electricity needs.

6.1 Overview of the Electricity Sector in Peru

6.1.1 Market Structure

206. The power sector in Peru was reformed and restructured between 1991 and 1993, followed by a privatization and concession process. A new legal and regulatory framework was established by the Electric Concessions Law (LEC) of 1992/93.⁶⁸ Ownership of major sector assets was transferred from public to private hands, together with the management and operation of the main electricity facilities. The new legal framework created a sector regulator, the Supervisory Commission for Investment in the Energy and Mining Sector (*Organismo Supervisor de la Inversión en Energía y Minería*, OSINERGMIN) and stipulated the methodology for rate setting, granting of concessions, customer service guidelines, and accountability of operators. The role of the State was limited to sector policy and general regulations, the granting of concessions, and basic sector planning.

207. The sector legislation recognizes two categories of electricity public service users, according to their amount of power demand. One category is the so called “large users,” that is, those with demands equal to or greater than 1,000 kilowatts (1 megawatt), and the other category is made up of the “small” regulated users. Large users (also called “free” users) contract their electricity supply directly with generators or distribution companies, through bilateral, freely negotiated contracts, under competitive, unregulated conditions. Distribution companies are obligated to supply electricity to small users in their concession areas at a regulated price established by the regulator. Operation of generation (the “dispatch” of supply) is executed by the System Economic Operation Committee (*Comité de Operación Económica del Sistema Interconectado*, COES).⁶⁹ Figure 6.1 schematically displays the Peruvian electricity market structure.

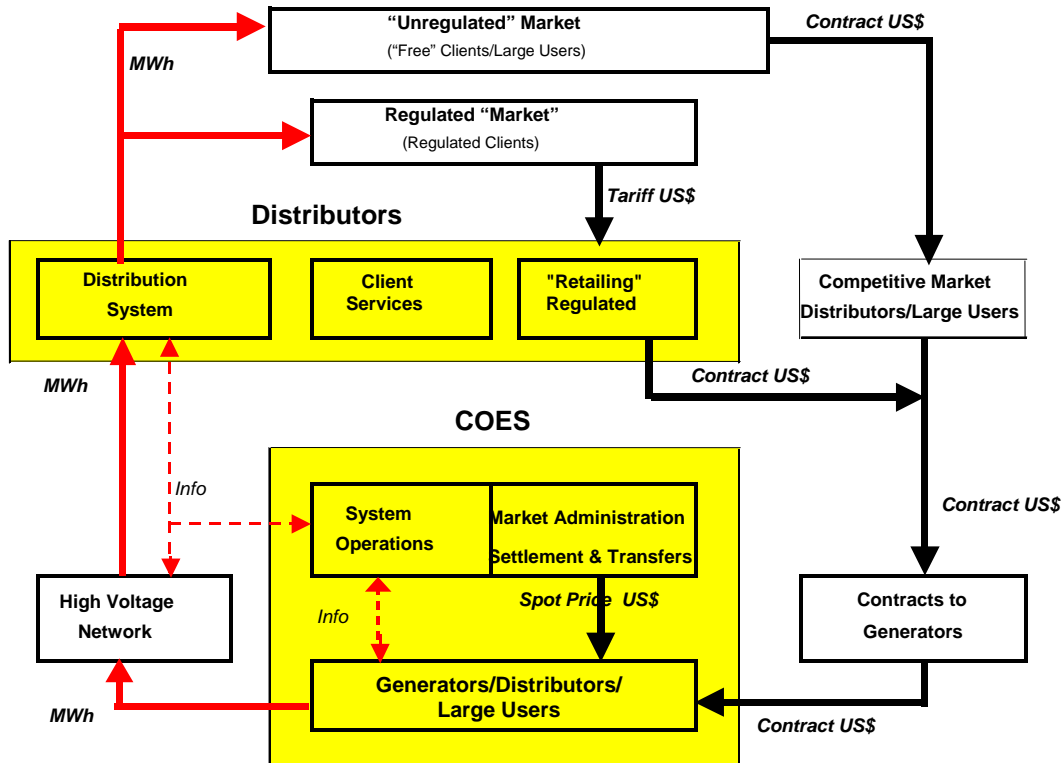
208. Until 1997, retail users consumed about 65 percent of the total electricity generated; large users consumed the remaining 35 percent. In the last 10 years, this

⁶⁸ The Electric Concessions Law (LEC) and its regulations; Law N°25844, and Supreme Decree (DS) N°009-93-EM.

⁶⁹ Real-time dispatch of generation supply is executed by COES following a cost-based merit-order procedure. The wholesale market is in reality a “differences market” of quantities contracted (bilaterally or through auctions). COES also manages the wholesale market, establishing payment obligations between generators, large users, and distribution companies in accordance with individual balance-of-energy dispatch.

proportion has changed, and in 2008, large users consumed 46 percent of the total. This latter percentage is relatively high compared to other countries in the region, where large users consume no more than 30 percent of the total. This greatly influences the electricity market because electricity suppliers can negotiate contracts for a large portion of the demand without the restrictions of a regulated price.

Figure 6.1: Peruvian Electricity Market Structure



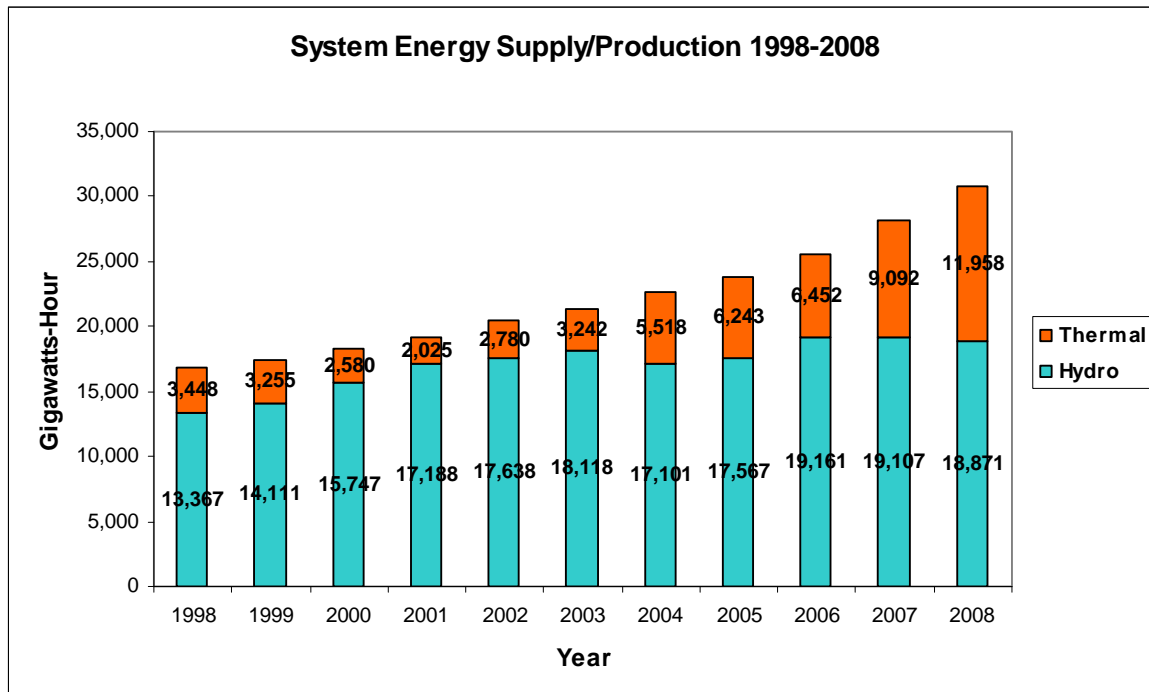
209. During the initial years of the sector reform, investments in generation, transmission, and distribution increased according to demand requirements, reaching a peak of about US\$760 million in 1999, followed by a drastic drop until 2003, when it was only about US\$230 million. Sector authorities and the Government were concerned about this drop in investment and the resulting lower generation reserve margin of the system. This was compounded by an extended dry period during 2003–04. Consequently, in June 2005, the Executive proposed to Congress a complementary electricity law to address the problems. In July 2006, Congress passed Law N° 28832, to “Ensure the Efficient Development of Electric Power Generation.” This new law introduced important changes to the LEC, mainly regarding generation and transmission regulation, the administration and functioning of the electricity market, and the determination of electricity prices.⁷⁰ The LEC and Law N° 28832 comprise the legal framework of the electricity sector in Peru.

⁷⁰ The most important changes introduced in Law N° 28832 were: (a) in generation, the establishment of an obligatory competitive auction mechanism to contract the supply to distribution companies; (b) in transmission, the formalization of transmission planning and a bidding process for building and operating

6.1.2 Electricity Supply

210. The electricity requirements of the country are fulfilled by two general sources: self-generation/consumption by some users (mainly “large” mining and industrial consumers) and by “public service” system generation. In 2008, self-generation was only 5.5 percent of the total, indicating the increasing reliance of the large mining industry on the electricity supply from the national system.⁷¹ In 2008, electricity production for public service was 30,829.2 gigawatt-hours (GWh), of which 61.2 percent came from hydro resources, the lowest percentage in the last five years (see Figure 6.2).

Figure 6.2: Evolution of System Energy Production, 1998–2008



211. This important reduction of the share of hydropower production in the overall electricity generation is the result of an investment shift from hydro to thermal, encouraged by investment-friendly characteristics of thermal plants and the low price of

the required system transmission expansion resulting from the planning; (c) changing the composition and governance of COES with the introduction of distribution companies and large users as new members; and (d) on prices, in generation, the pass-through of auction prices as part of the regulated generation tariff, and the stability of the transmission remuneration for existing facilities and transfer of the results of the bidding process for new facilities.

⁷¹ The major reduction in self-generation has been in hydropower, falling from a yearly production of just over 1,300 GWh during 1992–97, to only about an average of 430 GWh during 1998–2008 (in 2008, hydro self-generation was 462.2 GWh). Meanwhile, thermal self-generation maintained its yearly average production of about 2,000 GWh during the entirety of 1992–2008 (in 2008, thermal self-generation was 1,335.6 GWh).

gas.⁷² By comparison, thermal generation jumped from 3,242 GWh in 2003 to a record high of 11,958 GWh in 2008, a 270 percent increase in five years. Natural gas is the main thermal generation fuel, representing 31 percent of total generation. The remaining thermal generation is produced by oil-fired (diesel and residual) and coal-fired plants, representing 5 percent and 3 percent, respectively.

212. This noticeable increase in thermal production started in 2004, the beginning of operation of the Camisea natural gas pipeline. Gas-fired power capacity increased from 340 megawatts (MW) in 2004 to 1,313 MW in 2007, by a factor of almost four.

213. Year 2008 was critical for electricity supply. Private sector investments in generation were lower than expected and implementation of some projects was delayed. An indication of the gravity of the problem was that, for the first time since sector reform, the electricity system suffered power cuts of significant magnitude during two consecutive days in August 2008, due to congestion in the transmission system, capacity limitation in the Camisea gas pipeline, low hydroelectric generation, and lack of adequate reserve.

214. Some generation capacity numbers are misleading if not used correctly to measure the capacity reserve of a system, particularly if it has a great portion of hydro generation. In general, most hydropower-dominated systems are energy-limited (see Box 6.1). The hydropower plants developed in Peru have been mostly of the run-of-river type with no, or very limited, storage. Therefore, the difference between the hydropower capacity of the system during the wet season and dry season (and between a wet and a dry year) is considerable, affecting not only energy production but power capacity to cover peak demand.

Box 6.1: Reserve Margin

Generation installed capacity is not a good measure of the ability of a power system to supply peak power demand with adequate reliability (with enough reserve to support regular contingencies, like the probability of failure of some power plants). For example, the total system installed capacity in 2008 was 6,020 MW, much higher than the peak demand of 4,200 MW. This does not mean that the system has a high reserve level of more than 40 percent. First, hydropower capacity is limited by water availability; therefore, we should look at firm capacity of the system, the capacity during the dry season for hydro plants, and the available capacity for thermal plants (real output of the plants instead of the nameplate capacity). In 2008, the firm capacity of the system was about 5,100 MW. Second, the peak power demand is at the delivery end and firm capacity is at the supply end of the electrical system, therefore losses have to be considered. In 2008, the estimated total losses of the system were 13.1 percent (2.2 percent transmission, 3 percent sub-transmission, and 7.9 percent distribution); therefore, peak power demand seen from the supply end was about 4,833 MW.

In conclusion, the system generation reserve during the dry season in 2008 was only 5.25 percent, a low reserve level for a hydro-dominated system.

⁷² The only midsize hydropower plant constructed and commissioned in the last five years has been Yuncan, with an installed capacity of 135 MW. The project was financed and built by the public sector using a long-term soft credit from Japan, and was later transferred to the private sector.

215. If the planned new electricity generation comes on line as expected in 2009, some 590 MW of new gas-fired thermal units, and about 230 MW of hydropower, will provide the necessary additional power capacity to cover the expected demand and increase the reserve margin to a more comfortable level of over 20 percent. If the recent past is an indication, new investments in the sector, mainly by the private sector, have been very cautious and often well below the requirement, or produced with considerable delay. Overall, hydropower is perceived as a much higher risk investment than thermal generation.

216. The Government has taken action to prevent possible power shortages, passing an emergency decree⁷³ that allows publicly owned sector companies to acquire the necessary generation capacity if required. The cost of this generation will be incorporated into the electricity tariff, but its marginal cost will not be considered to determine the system marginal cost (it will not affect the price of transactions in the spot market). Electricity tariff increments will be different depending on the type of user, in proportions of 1, 2, and 4 for retail regulated users, small unregulated users, and large users, respectively.

217. Although the decree has a temporary application period of three years, and it is recognized as a necessary response to a potential critical situation in the sector, it is also true that, for the first time, a direct public intervention is affecting some basic principles of the 1992–93 reform. What is clear is that the Peruvian energy sector will face a difficult challenge in the coming years to cope with the increased demand resulting from its important economic growth and the necessity of a fresh look at sector structure and the market model.

6.1.3 Electricity Demand

218. Electricity consumption has been growing at an average rate of 8.14 percent during the last five years. The increases of consumption in the last two years, 2006–07 and 2007–08, have been 10.9 percent and 9.9 percent, respectively, indicating an increasing trend in line with the economic growth of the country. Most probably, the economic recession will impact this trend, reducing the electricity demand annual growth, in the short to medium term, to a more moderate level of 6 to 7 percent, or lower.

219. In 2008, industry electricity consumption represented 57 percent of the total, followed by residential consumption with 24 percent, commercial consumption with 17 percent, and other consumption 2 percent (of which public lighting is the largest). Total consumption in 2008 was 27,169.4 GWh. Peak-power demand in 2008 was 4,200 MW, 5.87 percent higher than in 2007, but significantly lower than the record increase of 10.8 percent from 2006 to 2007. Effective generation capacity was 5,562 MW, of which 2,946 MW (53 percent) came from hydropower. With a moderate peak demand growth of 6 percent, no less than 1,800 MW of new effective capacity will be needed to cover the future power demand in the next five years.

⁷³ Emergency Decree N°037-2008 of August 21, 2008, to “Ensure in a Timely Manner the Electricity Supply to the National Interconnected System.”

6.2 Price Regimes for Generation

6.2.1 Direct Sales to Large Consumers

220. The market of large users (the “free” market) in Peru represents 46 percent of the overall demand—a large market. In 2008, the electricity consumption of this market, made up of 247 users, was 12,587 GWh with a maximum power demand of 1,570 MW (37.4 percent of the system peak demand). Mining consumed 54.3 percent, followed by the smelting industry with 12.5 percent. Mining also represented the largest number of users, with 58. The load factor of this demand has been 0.915. The largest user is Southern Peru Copper Corporation (SPCC), which is also the largest copper mine in the country. SPCC’s contracted power demand in 2008 was 200 MW and its energy consumption was 1,632 GWh. The 10 largest users, of which six were mining companies, three were smelting/metallurgical industries, and one was a cement company, represented a contracted peak demand of 966.5 MW and electricity consumption of about 6,310 GWh in 2008 (one-half of total consumption of large users).

221. The average energy price in the free market was US\$44.5/MWh and the average energy-equivalent power (capacity) price was US\$10.6/MWh. Figure 6.3 shows the monthly variations of prices in the free market during 2008, and the busbar-regulated generation tariff (which includes the power capacity payment) for comparison. It can be appreciated that the free market price closely follows the values of the busbar-regulated tariff, in particular during the wet season (December–April), and it is higher during the dry season.

222. From the perspective of a hydropower developer, the free market is an important segment to look at for contract sales and, possibly, for financing. Mining and smelting/metallurgical industries mobilize large long-term investment and require security of electricity supply; this is why, traditionally, these industries have had self-generation and have developed their own hydropower in the past. Partnership of large users and power plant developers is an option that should be examined in more detail to overcome the reduction of investments and to address the risks of new hydropower generation. One example of this approach is the development of El Platanal hydropower plant.

223. Of note, 85 percent of the contracts in the free market are for periods of up to five years, and only five contracts provide for periods longer than 10 years, a duration more adequate for hydropower supply (Table 6.1).

Figure 6.3: Prices in the Free Market in 2008

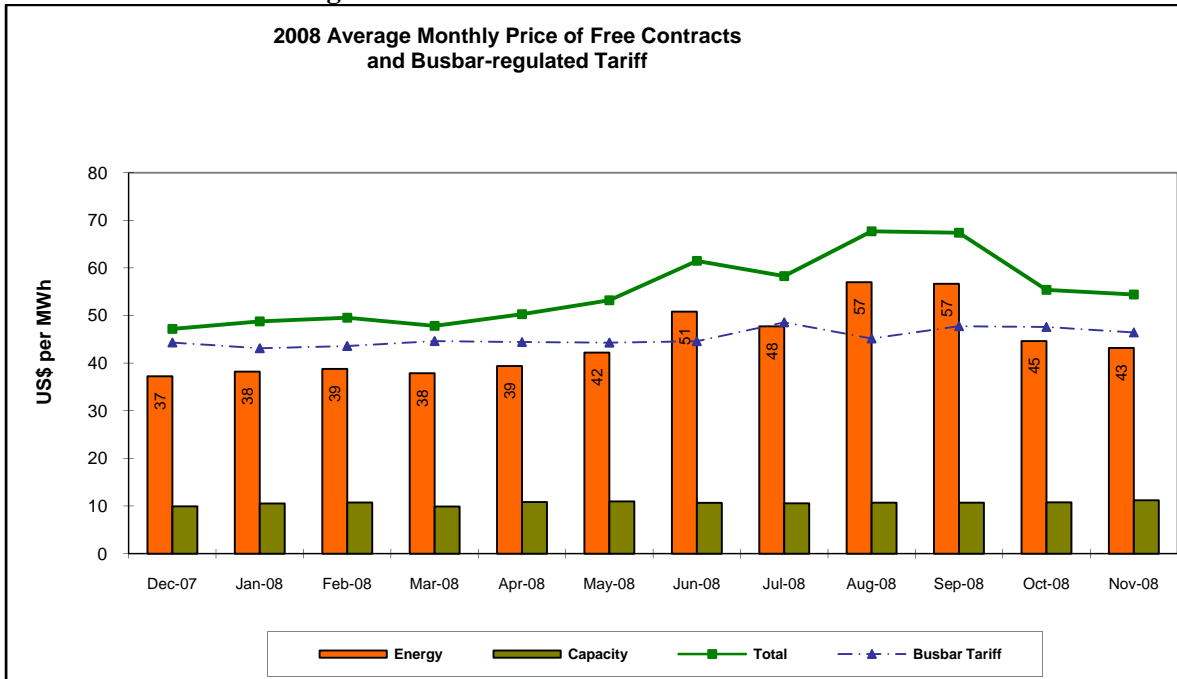


Table 6.1: Periods of Contracts in the Free Market

Period of Contract	Total Number of Contracts	Contracts with Generators	Contracts with Distributors
Up to 1 year	49	19	30
1 to 2 years	51	17	34
2 to 5 years	92	38	54
5 to 10 years	30	20	10
10 to 15 years	4	4	0
> 15 years	1	0	1
Total	227	98	129

6.2.2 Electricity Tariffs and Prices in the Regulated Market

224. The Peruvian electricity tariff scheme⁷⁴ is designed on the basis of full-cost recovery in each of the three segments—the generation, transmission, and distribution systems. The generation regulated energy tariff is determined by OSINERGMIN every year, according to the expected evolution of demand and generation supply capacity, fuel prices, competitive generation auction prices, and other economic parameters (like price indexes and inflation).⁷⁵ Real-time dispatch of generation supply is carried out by COES,

⁷⁴ Tariffs apply only to regulated electricity users—those with demands below 1 MW. Large users have no electricity tariff; they contract supply at free-negotiated prices with generators or distributors.

⁷⁵ The reference regulated “busbar” energy tariff is calculated by the regulator as the average marginal energy cost of the system, based on a three-year operation simulation (of the historical previous year and the next two prospective years). This reference price is weighted with the prices resulting from the supply

following a cost-based, merit-order procedure, independently of any bilateral contracts or the results of generation auctions. Hourly (in reality every 15 minutes) transactions between generators, distribution companies, and large users in the wholesale market are done at the “marginal/spot” price (of the last unit in the dispatch merit order). The wholesale market is in reality a “differences market” of quantities contracted (bilaterally or through auctions) and “demanded” by the dispatch. COES also manages the wholesale market, establishing payment obligations between generators, large users, and distribution companies.

225. In setting tariffs, the 24 hours of a day are divided into two blocks—one of 5 hours between 18:00 and 23:00, called the “peak period,” when demand is highest, and the remaining 19 hours, called the “off-peak period,” when electricity demand is lower. The energy tariff is calculated and prices are offered by generators for these two hourly blocks. Due to the cost-based, merit-order operational dispatch, it is obvious that the peak energy price is higher than the off-peak price.

226. The transmission and sub-transmission networks have open access and tariffs are regulated under an economic cost-based procedure and the results of competitive bidding for transmission facilities required according to a transmission planning procedure. Transmission tariffs are recalculated every year. The Distribution Tariff (*Valor Agregado de Distribución*, VAD) is regulated under a cost-based efficient model company, for each of five “typical distribution sectors” (urban high density, urban medium density, urban low density, urban-rural, and rural). The VAD for the different zones and distribution companies is recalculated every four years. The tariff for a typical regulated final user consists of the generation tariff, G_T + the transmission tariff, T_T + the distribution tariff, VAD.

227. Transmission and distribution tariffs are regulated for all types of users. Generation, on the other hand, has different “price” regimes—a generation tariff for small users, established by the regulator, and two options for large users: (a) negotiate electricity quantities and prices directly with suppliers (generators or distributors); or (b) participate in the supply auctions contemplated in the regulations, as part of an aggregated demand with distributors. Quantity and price will then be the result of the auction.

228. In the operation of the generation wholesale market, two price parameters are important: (a) the marginal (“spot”) energy price used by COES to balance “transactions” among generators, and (b) the “busbar”,⁷⁶ energy tariff calculated by the regulator every year, based on a three-year economic operation simulation, combined with the price

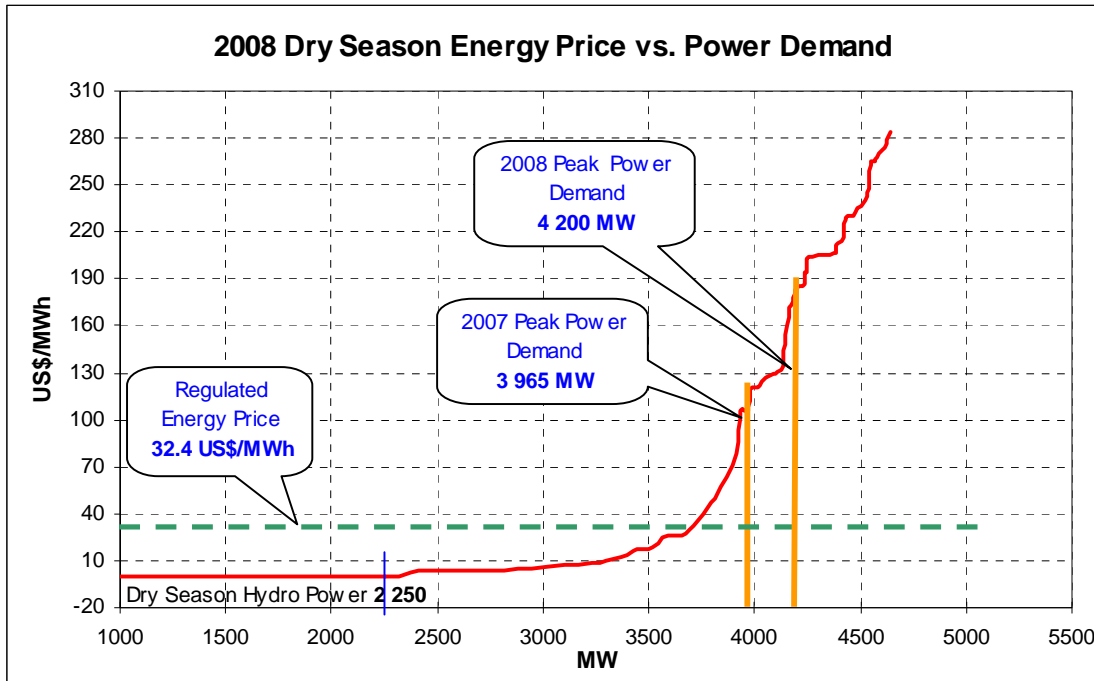
auctions to obtain the final energy busbar price applied in the tariffs. At present, 65 percent of the regulated energy price comes from auctions and 35 percent comes directly from the reference busbar price.

⁷⁶ The term “busbar” is commonly used in the power systems field to refer to the network nodes of the transmission grid (usually the main substations of the system). Generation prices are calculated for each of the main nodes (the difference in prices between nodes are the result of transmission losses). If no specific node is mentioned, usually prices are referred to Santa Rosa, the main node located in Lima.

results of supply auctions carried out by distributors. Distribution companies pay to generators the energy supplied at the regulated generation energy tariff.

229. The marginal energy price is a continuously fluctuating value determined by the operating cost of the most expensive (the last) generating unit needed to cover the peak power demand of the system at a specific moment. For example, Figure 6.4 (in red) presents a typical relation of the cumulative generation capacity (in the X-axis), stacked up in order of increasing operational cost of generating units (in the Y-axis) for the dry season in 2008.

Figure 6.4: Curve of Generation Energy Price Compared to Power Demand for Dry Season



230. As can be seen, the cost of generation is zero up to the hydropower capacity of 2,250 MW, and then starts to increase as thermal plants are needed to cover the demand. Up to 3,250 MW of demand, the marginal operation cost is below US\$10/MWh. Then, between 3,250 MW and 3,800 MW, the marginal operation cost starts to climb to about US\$50/MWh. The last section of the curve has a steeper ascent of about US\$150/MWh to reach the value of US\$200/MWh in just a 450-MW increase in demand (just above the 2008 peak demand). For reference, also shown is the 2008 average regulated energy price (tariff) in green (with a value of US\$32.4/MWh). The marginal cost curve (in red) is not static. If on a given day there is one generating unit out of service (due to maintenance or a forced outage), the portion of the curve corresponding to the power capacity of the unit has to be taken out, and the remainder of the curve is moved to the left to close the gap, thus increasing the marginal costs at higher levels of consumption.

231. Because of the highly fluctuating nature of the marginal cost, it is standard practice to use, for comparisons, daily, weekly, monthly, or annual averages instead.⁷⁷ Table 6.2 and Figure 6.5 show the evolution of the average energy marginal price and tariff in the 10-year period, 1998–2008. It can be appreciated that, during 1998–2002, the marginal price was below the regulated tariff; thereafter, the marginal price started an increasing trend, reaching a record high in 2008. Table 6.2 also includes the monthly highest and lowest average marginal prices in each year, showing a significant range. Note that values of average marginal cost and regulated tariff did not differ much between 1998 and 2002, but from 2003 onward the regulated generation energy tariff has been much lower than the marginal cost.⁷⁸

Table 6.2: Evolution of Average Electricity Prices, 1998–2008

Energy Marginal Price and Tariff at Generation Level				
Year	Marginal Price in US\$ per Megawatt-hour			Tariff
	Higher	Lower	Average	US\$/MWh
1998	35.53	10.80	24.4	25.5
1999	33.64	5.93	16.1	24.8
2000	37.44	5.81	21.9	27.1
2001	39.18	7.30	22.1	28.7
2002	51.23	10.34	27.2	28.3
2003	65.89	11.14	38.3	27.1
2004	112.39	23.94	68.5	22.3
2005	98.81	21.85	63.8	29.5
2006	149.81	24.06	68.1	29.0
2007	65.45	25.00	38.3	29.7
2008	236.00	17.00	89.4	32.4

232. As shown in Figure 6.5, 2007 had much better (lower) marginal costs than the previous three years, with values similar to 2003. Figure 6.6 shows that this decreasing trend continued during the five first months of 2008, but the problems started in June with a threefold increase, and then reaching a historical monthly record high of US\$236/MWh in July 2008.

⁷⁷ Marginal costs are registered every 15 minutes for purposes of balancing transactions; therefore, in a single day there are 96 values, and in a year 35,040 values.

⁷⁸ This situation was one of the major factors that forced some generation companies to refuse to contract supply to distribution companies for the regulated market, and pushed for the regulatory changes in 2006.

Figure 6.5: Evolution of Average Electricity Prices, 1998–2008

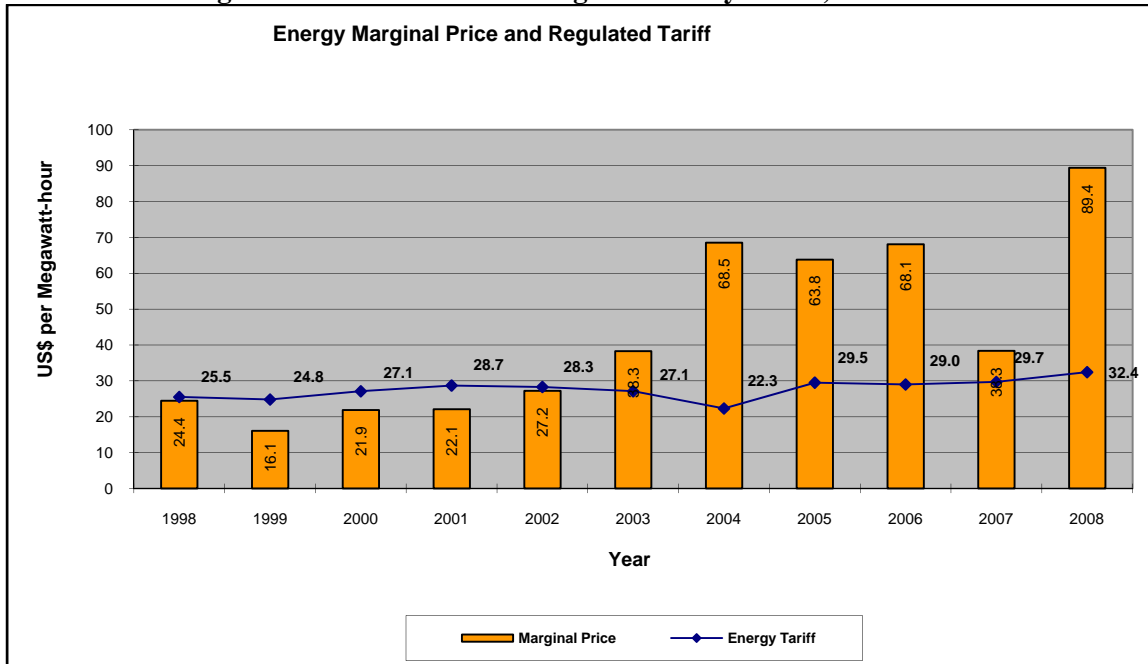
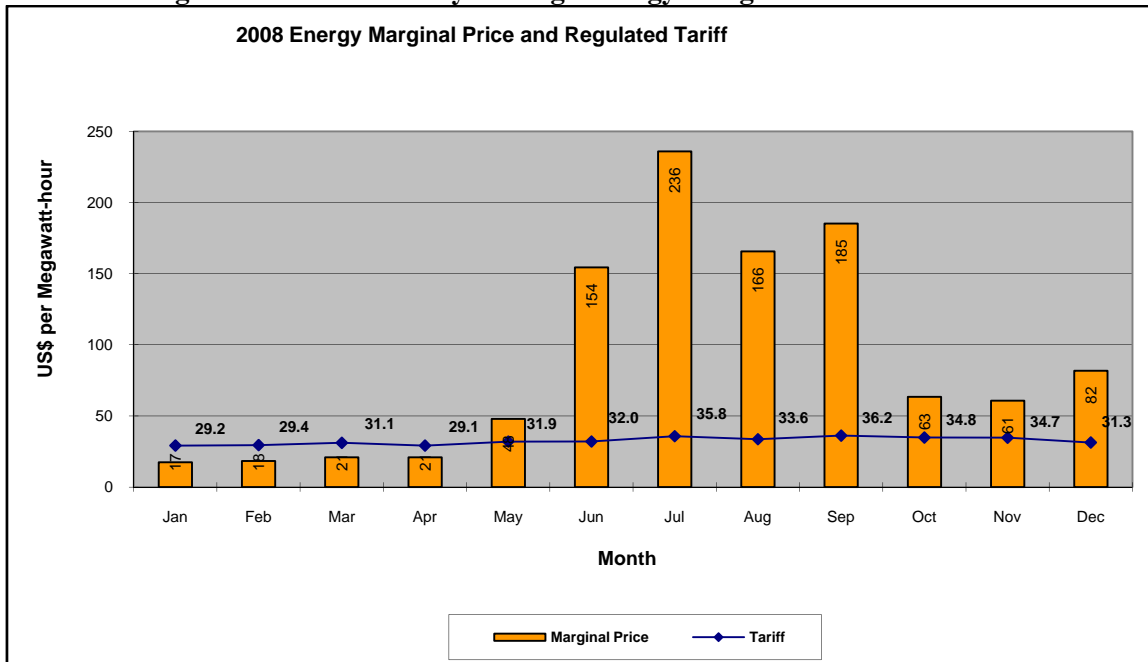


Figure 6.6: 2008 Monthly Average Energy Marginal Price and Tariff



233. An important characteristic of the Peruvian electricity price system is that supply charges and payments to and from final users and between wholesale market participants are based on a two-part tariff system, very similar to the classical scheme of peak-load pricing of capacity and energy charges. The capacity payment is based on the annualized investment and operation and maintenance costs of a peak-load generation unit, of

“adequate capacity in relation to the size of the system and the reserve requirements” (this quantity is called “base price of power” in the regulations). The regulator determines the main characteristics of this unit each year, for application in the periodic review of generation tariffs. The present reference peaking unit is a 175.6-MW open-cycle natural-gas-fueled unit (reference investment is taken from statistics of the last five years published by *Gas Turbine World* magazine).

234. The capacity payment received by each unit is determined by the contribution of the unit to cover the peak demand and the “base price of power.” The contribution of the unit to cover the peak demand is based on the unit’s “firm capacity” adjusted by a factor necessary to “fill” the total demand of the system plus the required reserve margin, by stacking up the “reduced” (or augmented) firm capacities of generating plants (first the hydro and then the thermal plants).

235. Firm capacity of thermal units is relatively well defined in the technical literature, and availability factors for different types of thermal units are regularly compiled and published. Therefore, there is high certainty in estimating future revenue coming from capacity payments for thermal plants. On the other hand, in the case of hydroelectric plants, the probabilistic nature of hydrology introduces a risk factor not present in the case of thermal plants. Therefore, the firm capacity of hydro plants is linked to the probability of the persistence of the available water flow. The Peruvian regulation establishes a 95 percent hydrologic probability persistence to define the firm capacity of a hydro plant.

6.3 Power Generation and Natural Gas Policies

236. The Peruvian electricity sector is strongly linked and dependant on natural gas supply from the Camisea Gas Field, with relatively large reserves. Although the legislation of the Peruvian hydrocarbon sector considers the sector to be part of a competitive market, the Government has a particular interest in establishing related sector policies, particularly regarding internal consumption and conditions for exporting. The situation of the natural gas supply from Camisea, particularly the limitation of transport, has affected and could continue to affect electricity generation.

237. The Camisea project started operation in August 2004. Transport of natural gas from Camisea is provided by a single pipeline from the field to the city gate in Lurin, 60 kilometers (km) south of Lima, in the charge of *Transportadora de Gas del Peru* (TGP). From Lurin to Lima-Callao (the terminal station) the transport is provided by Calidda, the Lima gas distribution company. There is also a pipeline section from the terminal station in Callao to Ventanilla (the northern part of Lima), where a major thermal plant, of the same name, is located. The other three power plants using Camisea’s natural gas are Santa Rosa, located in downtown Lima; Chilca; and Kallpa, located in Chilca, 70 km south of Lima, near the city gate.

238. The pipeline has different sections along its route with decreasing diameters and capacities. The initial section of about 211 km, from the field to the end of the jungle

area of the route, has a maximum capacity of 1,200 million cubic feet per day (MMCFD). The second section, of 297 km, in the Andes area, has a maximum capacity of 450 MMCFD. The third section, of 226 km, up to the city gate, on the coast, has a capacity of 400 MMCFD, and the pipeline section of 60 km from the city gate to the terminal station in Callao, has a capacity of 200 MMCFD. Finally, the pipeline of 7 km that supplies gas to the Ventanilla power plant has a maximum capacity of 150 MMCFD. The actual compression installations of the transport pipeline are not sufficient to allow the use of the second and third sections of the pipeline at their maximum capacities. The present estimated capacities of these sections are 250 MMCFD and 200 MMCFD, respectively. Although TGP is already in the process of expanding the compression installations, it is expected that a first stage of the required facilities, for a capacity of 380 MMCFD, will be operational by mid-to-end 2009, and that the second stage, to reach the maximum capacity of 450 MMCFD, will be ready by the beginning of 2010.

239. Camisea natural gas use for power generation started modestly, providing, until the end of 2004, the fuel requirements of a single generating plant (Ventanilla), totaling a consumption of 360 MMCF. The power generation consumption grew very fast, reaching almost 46,000 MMCF in 2007, representing a daily average of 125.6 MMCFD. Estimates of power demand for Camisea's gas, for the next five years, indicate an 80 percent increase to about 235 MMCFD by 2012, which corresponds to between 700 MW to 800 MW of additional gas-fueled thermal power. The current capacities of the last sections of the pipeline are starting to create bottlenecks to the supply of gas. The demand in 2008 for power generation was 164 MMCFD, and for other uses about 76 MMCFD, totaling 240 MMCFD, greater than the present capacity of the coastal section and practically at the limit of the capacity of the Andean section.

240. Once the full capacity of the Camisea pipeline is available by 2010, the MEM has estimated that between 2,200 MW and a maximum of 2,800 MW of new natural-gas-fired thermal generation could be installed using the reserved natural gas from Camisea for internal use (discounting other uses except power generation). The Ministry of Energy and Mines (MEM) has also indicated that the electricity sector should not rush to implement this amount but should use other alternative energy sources like hydro or wind. How this policy would unfold, considering the cheap price of natural gas from Camisea, is not clear.

241. The Camisea natural gas price for internal use in power generation is one of the cheapest in the region, introducing a distortion in the power market, particularly for the development of alternative generation like hydroelectricity. This price is also a disincentive to the efficient use of natural gas in thermal power generation, making it uneconomical to install combined cycle units.

242. Table 3.2 in Chapter 3 shows the 2008 Camisea natural gas price for power generation for each of the four main thermal power plants. Although the cheap price of gas is translated into a low energy production cost of the thermal plants, electricity users have an additional charge in their bills to pay for what is called the Main System

Guarantee (*Garantía de Red Principal*, GRP⁷⁹), which compensates part of the investment cost of the gas pipeline.⁸⁰ The price of natural gas at the point of generation in Lima and nearby locations is around US\$2.2 per million British Thermal Units (mmBTU). These prices are among the lowest in the world (for comparison, see Table 3.1 in Chapter 3).

243. An effort to estimate the economic cost of natural gas based on a netback value approach concluded that, for a scenario characterized by a long-term crude oil price of US\$75 per barrel, the netback value of gas would be US\$4.4/MMBTU, that is, twice as much as the current price for power generation. It is understood that MEM's policy regarding the price of Camisea natural gas is to maintain this promotional internal price at least for the period stipulated in the renegotiated contract with the producers (which allows for no more than a 5 percent increase in the price of natural gas annually, and not larger than the percentage increase of liquid fuels) and, after this initial period of five years, the annual increases should be lower than the percentage increase of liquid fuels. It should be noted, however, that this price policy is exclusive to the initial fields of Camisea (known as lots 48 and 55) and does not apply to any other exploitations or natural gas fields in the same area of Camisea or in other places.

244. Finally, recently, due to supply limitations, the MEM has established a priority order to supply natural gas, maintaining the existing contractual obligations, mainly the LNG export contract to Mexico. The order of priority starts with gas supply to residential consumers, followed by compressed natural gas for transportation and then for power generation (for combined cycle first and, then, for open cycle units). Industrial and commercial users have been relegated to the end of the list and would have to compete with future exports for natural gas supply.

6.4 The Peruvian Supply Auction System

245. Two main changes in generation regulation introduced in the reform Law N° 28832 of 2006 were the establishment of obligatory supply auctions by distribution companies, to ensure service to regulated users, and a new procedure to determine the generation energy tariff for regulated users, under which the price(s) resulting from the supply auctions constitutes a main component of the generation energy price. Similar regulatory changes were introduced in other countries in the region (Brazil, Chile, and Colombia) to attract adequate levels of investment for required new generation.

246. The basic scheme of the Peruvian electricity auction system, established by Law N° 28832, has the following main characteristics:

⁷⁹ Studies for the Camisea gas pipeline indicated unattractively high transport tariffs, due to the expected low demand during the initial years of gas production. Investors in the pipeline required the Government to guarantee a minimum capacity usage/payment during the first years of operation. MEM and the regulator designed the GRP as a payment guarantee.

⁸⁰ For example, in 2007, the gas transport tariff to pay for the GRP was US\$1.381 per megawatt-month, which is equivalent to approximately US\$0.245¢ per kilowatt-hour. The GRP is reaching its termination; therefore, its tariff was reduced considerably in 2008 (to about one-fifth of the 2007 GRP tariff).

- Generation supply to distribution companies for regulated users could be established through: (a) direct contracting at a price not greater than the node (also known as “busbar”) generating tariff determined by the regulator, or (b) contracts resulting from competitive supply auctions.
- The expected demand of regulated users should be fully contracted by distributors, at least for the next two years.
- Distributors could combine their demands to participate jointly in a supply auction, and large (“free”) users could request to incorporate their demand in a supply auction.
- Distributors should call for supply auctions with anticipation of not less than three years before their demand requirement, and with a contractual duration of not less than five years, since a shorter length of time is insufficient for development of medium-to-large-scale hydro plants.
- During the initial three-year transitory period of application of the law (that will end in June 2009), the supply auctions could be done with anticipation of less than three years and for contractual periods of less than five years.
- The regulator will establish a “sealed” price cap in each auction, above which no offer would be accepted. The regulator could modify the price cap after each deserted auction round.

247. In April 2007, the sector regulator OSINERGMIN established the General Guidelines and Model Contract for the Supply Auctions (Resolution 101-2007-OS/CD), to be used by the distribution companies during the three-year transitory period. Subsequently, in October 2008, MEM approved the general regulations of the supply auctions (DS 052-2007-EM) and OSINERGMIN, in December 2008, approved the Procedures for the Long-Term Supply Auctions (Resolution 688-2008-OS/CD).

248. The general regulations for auctions approved by MEM’s and OSINERGMIN’s procedures for long-term auctions establish additional rules, including:

- The procedure for temporary auctions established a sealed-enveloped method to present proposals. In the permanent regulations, distributors could opt between the sealed-envelope and an electronic “descending clock” method carried out by an auctioneer.
- Generators can present more than one independent offer.
- Offers can be presented for a period shorter than the one requested by distributors.
- The offered quantities (power and associated energy) by generators should be specified for each month of the year, not decreasing during the offered period.
- Bids are accepted in ascending price order, if lower or equal to the price cap, up to the requested power quantity, or until there are no more bids.
- Winner proposals are paid-as-bid (a discriminatory price auction).
- The price cap is disclosed in case the auction is declared, fully or partially, deserted (100 percent of the quantity demanded has not been covered), and at least one of the bids has a price higher than the price cap.
- If the demanded quantity has not been fully covered, a new bid round will be called to complete the requested quantity. There is no obligation of generators

- that participated in a previous bid round to participate in the new round, nor a prohibition on participating in a bid round if a generator did not participate in previous rounds.
- If auctions are called for with an anticipation of more than three years, distributors will receive a payment incentive,⁸¹ which will be added to the generator price of the auctions, and then passed through to consumers; this incentive could not be higher than 3 percent.

249. There were two other important pieces of legislation approved in 2008 to promote hydropower generation and are related to the auction system. First, Legislative Decree (DL) N°1041 extended the initial 10-year maximum contractual period stipulated in Law N° 28832 for the winning bids in the auctions, to a period of 20 years (more in line with long-term financing of hydro plants); and introduced a “discount” to the price offered by hydropower generation, participating in supply auctions, when compared with other technologies (basically, thermal generation). The applicable discount will be established by the regulator in each auction. Second, Legislative Decree (DL) N°1058 provided a tax incentive, allowing an accelerated depreciation of five years for the investment capital in hydropower.

250. The main purpose of the supply auction transitory period was to correct the existing deficiency of distribution companies in their supply obligations, due to the “refusal” of generators to contract supply at the regulated tariff. As a result of this situation, an important portion of the regulated demand was not covered by supply contracts; therefore, the distributors involved were “taking” their required supply from the system and consigning their corresponding payments, calculated at the regulated generation tariff.

251. During the transitory period there were 10 different auctions, two in 2006, three in 2007, four in 2008, and one in 2009 (Table 6.3). The requirements of the first auction in 2006 were practically fully covered in one round, and in the second auction, 70.3 percent was covered, in two rounds (the second round was deserted). The average price of these two auctions was 9.11 Nuevos Soles per MWh.

252. The auctions held in 2007 and, in particular, in 2008, were less successful, reaching a reduced coverage (with many cases declared deserted) despite higher price caps. It is clear that many auctions under the temporary regime were successful, particularly when publicly owned distribution companies were involved. It appears that generators have been reluctant to contract at prices close to the regulated tariff, considering that the marginal prices are at levels well above the regulated tariff. Under the chosen scheme based on a sealed price cap, generators have an incentive to bid a high price in the initial round to discover the price cap and then be in a better position in subsequent rounds, once the initial price cap is disclosed. Although the temporary

⁸¹ The incentive formula is: PI (in percent) = $(MA-36)^2/2 \times 6^3$; where PI is the price incentive in percentage of the average winning auction price, and MA is the number of months in anticipation of the required quantity, when auction is called for (greater than 36). Note that an auction call with an anticipation of 6 years (72 months in advance) will give an incentive of 3 percent to the distributor, the maximum allowed.

regime is now completed, sector observers think that the future auctions, under the permanent regulations for long-term contracts, could also confront similar difficulties if some changes are not introduced to correct deficiencies and if price caps remain low.

Table 6.3: Auctions during the Transitory Period, 2006–09						
Year	Distribution Companies in Auction	Round	Date	% Cover	Accepted Average Price US\$/MWh	Price Cap US\$/MWh
2006	Distriluz – ElectroSur	1	18.12.06	99.2%	2.846	2.85
	Luz del Sur – Electro Sur Medio (ELSM)	1	18.12.06	70.3%	2.846	2.85
		2	16.03.07	Deserted	—	Not opened
		Total		70.3%	2.846	
2007	Edelnor – Luz del Sur	1	06.09.07	66.7%	3.347	3.516
		2	18.11.07	13.1%	3.515	3.49
		3	06.12.07	Deserted	—	3.496
		4	27.12.07	15.8%	3.469	3.513
		5	28.02.08	3.5%	3.294	3.512
		6	31.03.08	0.9%	3.462	Not opened
		Total		100%	3.386	—
	Luz del Sur – ELSM – Edecañete	1	13.12.07	74.3%	3.476	3.567
	Coelvisac	1	27.12.07	Deserted	—	Not opened
		2	12.02.08	Deserted	—	Not opened
		3	08.04.08	Deserted	—	Not opened
		4	09.05.08	Deserted	—	Not opened
		5	30.05.08	Deserted	—	Not opened
2008	Hidrandina – Electro Nor Oeste – Electrocentro – Electro Ucayali	1	04.01.08	Deserted	—	Not opened
		2	28.02.08	Deserted	—	Not opened
		3	31.03.08	19.1%	3.611	Not opened
		4	30.04.08	3.3%	3.766	3.903
		Total		22.4%	3.634	—
	Electro Sur Este – SEAL – ElectroSur – Electro Puno	1	04.01.08	Deserted	—	Not opened
		2	31.03.08	Deserted	—	Not opened
		3	28.04.08	Deserted	—	Not opened
	Electro Sur Medio	1	24.10.08	Deserted	—	Not opened
		2	01.12.08	Deserted	—	Not opened
		3	12.01.09	Deserted	—	Not opened
	Luz del Sur – Edecañete	1	22.10.08	30%	4.333	4.444
		2	12.12.08	Deserted	—	Not opened
		Total		30%	4.333	—
2009	Hidrandina – Electronoroeste – Electronorte – Electrocentro – SEAL – Electro Puno – Electro Sur Este	1	30.01.09	Deserted	—	3.604

253. The Peruvian supply auction system is different from the Brazilian and Colombian schemes in various ways. First, in the Peruvian system there is no distinction in the source of supply between existing and future plants or in the type of generation, thermal with any fuel or renewable, hydropower in particular. Also, there are no auctions

for projects. What is auctioned is the electricity supply (the power and energy output of plants), not specific projects. Although there is no prohibition in the regulations to limit the supply auction to a particular type of generation, the logical interpretation of the regulations is that all kinds of generation should compete openly in the auctions.

254. Another important characteristic of the Peruvian auction system is that the basic quantity that is auctioned is the power demand and its “associated” peak and off-peak energy. Prices offered are only on energy (peak and off-peak), while power payments are provided through the standard procedure of capacity payments (i.e. an administrated price). Power requirements/offers are split into two parts—minimum fixed portion, which will be provided/taken (and paid) by generators/distributors, and a variable additional optional quantity (up to 20 percent of the fixed quantity), requested by distributors. The fixed part is considered a take-or-pay portion, and the additional amount is paid as taken with no obligation for a minimum take. Firm energy, like in Brazil, or “reliability” supply, like in Colombia, is not part of the Peruvian scheme.

6.4.1 Hydropower and the Auctions System

255. Although the regulations of the auction system are not discriminatory toward any particular technology, some stipulations could impact hydro or thermal generation differently. One example is the anticipation period of not less than three years required to call for bids. Most thermal plants can be built within three years; therefore, new thermal generation could participate in the auctions. However, it takes more than three years to build most medium-to-large-size hydro generation plants; therefore, new hydropower plants would not be able to participate in an auction called with such anticipation. Also, increasing the anticipation period tends to increase the distributors’ risks, to which distributors see no advantage.

256. The proposed solution to this problem has been the introduction, in the regulations, of an economic incentive for distributors (with a ceiling of 3 percent) to call for bids with anticipation greater than three years. The problem with the approved mechanism is that the said incentive appears insignificant when weighed against the risks of making an advanced commitment. Also, it poses an additional cost to consumers without a clear economic benefit. Furthermore, the incentive, as designed, could create opportunistic behavior among distributors in order to obtain the price benefit without a real need to increase the period of anticipation. A more effective alternative is to force the period of anticipation, in some auctions, to the number of years required to build new hydropower plants. For example, in the Brazilian auction system, bids for “new energy” (provided by new plants) are called for with different anticipations of three, five, or seven years.

257. Another important theme is the discount on hydro energy prices introduced recently to the auction system. Depending on the amount of the discount, this measure could have an important positive impact in promoting hydropower generation. However, an intervention of this type could introduce (or extend) price distortions in the sector and produce a suboptimal plant mix, if the discount amount is not economically rational. The general rule to have an economically efficient discount is to establish this amount just

high enough to compensate the “barriers costs” of hydro and/or other existing price distortions that favor other technologies. If the discount amount is lower than needed, sufficient hydro capacity would not be obtained in the auctions. If the discount is too high, some inefficient hydropower would be obtained. As indicated in Chapter 3, the avoided cost of an equivalent thermal plant combining an open cycle combustion turbine (OCCT) and a combined cycle gas turbine (CCGT),⁸² calculated at the economic cost of gas, would be the economically justified reference for the estimation of the discount.

258. Another point worth mentioning, irrespective of the auction rules, is the intrinsic greater difficulty that hydropower projects have in devising a successful bidding strategy in the auctions compared with thermal plants. Effective capacity of thermal plants is well defined and energy output in practice has no constraint up to this capacity limit.⁸³ So these plants face minor risks when bidding in an auction. On the other hand, effective capacity and energy output of hydro plants are probabilistic values, which have seasonal and yearly variations, and therefore imply greater risks in an auction.

259. Hydro firm capacity, and its associated energy, is the only “secure” quantity that can be offered in an auction; the question is at what price. For most hydro plants, it would be prohibitive to price the firm energy at a value to recover all their revenue requirements, since in this way, it is likely that they would not be competitive. Firm hydro energy has to be priced at a level competitive with equivalent base-load thermal generation (combined cycle gas-fired plants). At this price, not all revenue requirements will be covered. The additional required revenue should come from the effective capacity payments and the additional available energy (the “secondary energy”) of the plant. Here, there are two possibilities: (a) sell all the additional capacity/energy in the auction at a higher price than the firm energy price; or (b) sell only part of the additional capacity/energy in the auction and leave the remaining to be “sold” to the system, in the future, at the marginal energy price.⁸⁴

260. Since hydropower projects have specific individual characteristics, their participation in auctions has to be carefully planned, defining the available portfolio of projects, the minimum requirements to be part of the portfolio, and the type of power mix economically desirable. It is clear that a centralized auction scheme, as opposed to the actual decentralized system in which the distributors “control” the auctions, would be much more effective in establishing adequate demanded quantities and guiding the auctions to obtain a better (more economic) systemwide plant mix.

⁸² The presumption is that in the absence of the hydro project, the equivalent energy and capacity would be provided by a mix of open cycle and combined cycle gas-fired projects.

⁸³ This condition applies only when there are no constraints in fuel supply. As indicated elsewhere in this report, this has not been the case for the Camisea natural gas, which, in 2008, had (and will continue to have in the short term) transport limitation in its pipeline, and also some production limitations.

⁸⁴ Merit-order dispatch of generation by marginal energy cost assures hydro plants operation under all conditions; therefore, they will always receive payment for energy sold to the system without a supporting contract, bilateral or as a result of an auction process. On the other hand, thermal energy without a contract has to compete in price to be dispatched and receive payment.

6.4.2 Bidding Out Individual Hydro Projects

261. An important point to consider carefully is the advantage of bidding out individual hydro projects, like the case of Rio Madeira in Brazil. Brazil's recent experience in auctioning the Madeira projects, (two large hydropower plants located in the state of Rondonia, adding 6,500 MW, that had been prepared by a single consortium), yielded a cost reduction of around 30 percent, which will represent a saving to consumers of around US\$500 million per year. The success of the Rio Madeira auction in achieving an effective competitive process can be attributed to a great extent to the assessment of technical risks made available through the participation of a small group of highly qualified international experts. To this end, the Brazilian Ministry of Mines and Energy (MME) engaged through the World Bank the support of three experts and a specialized consulting firm to assess the main risks associated to the project, namely: (a) a sound estimation of the project's capital costs, (b) the design of an auction for a large-scale project, (c) assessment of the projects' sedimentation problems, and (d) an independent assessment of the design of the project's turbines. This effort in breaking the asymmetry of information was complemented by a MME program to disseminate the findings of the technical studies among all interested parties, and a regulatory framework that permitted the bidding of projects at this stage while recognizing the commercial value of the preparatory work done by the group that had been preparing the project.

262. Bidding out individual hydropower projects incorporates strong efficiency incentives toward better project design and implementation, and addressing the conflicts of interest that are often inherent in consortiums preparing infrastructure projects.⁸⁵ Project auctions could prove to be extremely beneficial in large projects, such as those being prepared in the eastern basins for export to Brazil, due to the scale of the resources at stake and, subsequently, the very large potential savings. The Peruvian auction scheme does not directly contemplate this possibility; therefore, specific additional regulations would have to be established. Given the complexity of large hydropower projects, which require extended studies and expensive field investigations, a main challenge is how to attract competition to a project that is often being prepared by a single group and, hence, has a unique and privileged understanding of the project's challenges and risks. It is therefore essential for the Government to find a way to break this information asymmetry. As learned from the experience of Rio Madeira, this can be done through independent technical studies on the main risks of the specific project, and making this information available to all interested parties. This technical effort should also include an independent assessment of project costs in order to provide the basis for a price cap at the auction process.

263. Another matter that requires regulation in this case is the procedure of transferring the acquired supply to the demand (distributors and large users), and the corresponding contractual arrangements. It is obvious that the introduction of project-specific auctions

⁸⁵ A common arrangement of many consortiums engaged in large hydropower projects is to include, often as the leading partner, a contracting company. This introduces a complex and conflictive set of incentives within the group, since while the interest of some partners focuses on the business of selling energy, other partners—the contractor(s)—are also interested in maximizing profits during the construction phase.

will affect the regular auction system, reducing the quantity of demand available for competitive auctions. Once again, the present decentralized auction system does not seem to fit properly to this type of bidding, which requires public sector coordination and the contribution of a central planning approach in providing adequate efficiency signals. This challenge is even greater when dealing with projects aimed at exporting electricity since, in these cases, defining the shares of energy to be exported and to be kept for the domestic market will require the support of a sound central planning effort aimed at optimizing economic benefits for the country.⁸⁶

6.5 Sector Investments and Private Participation

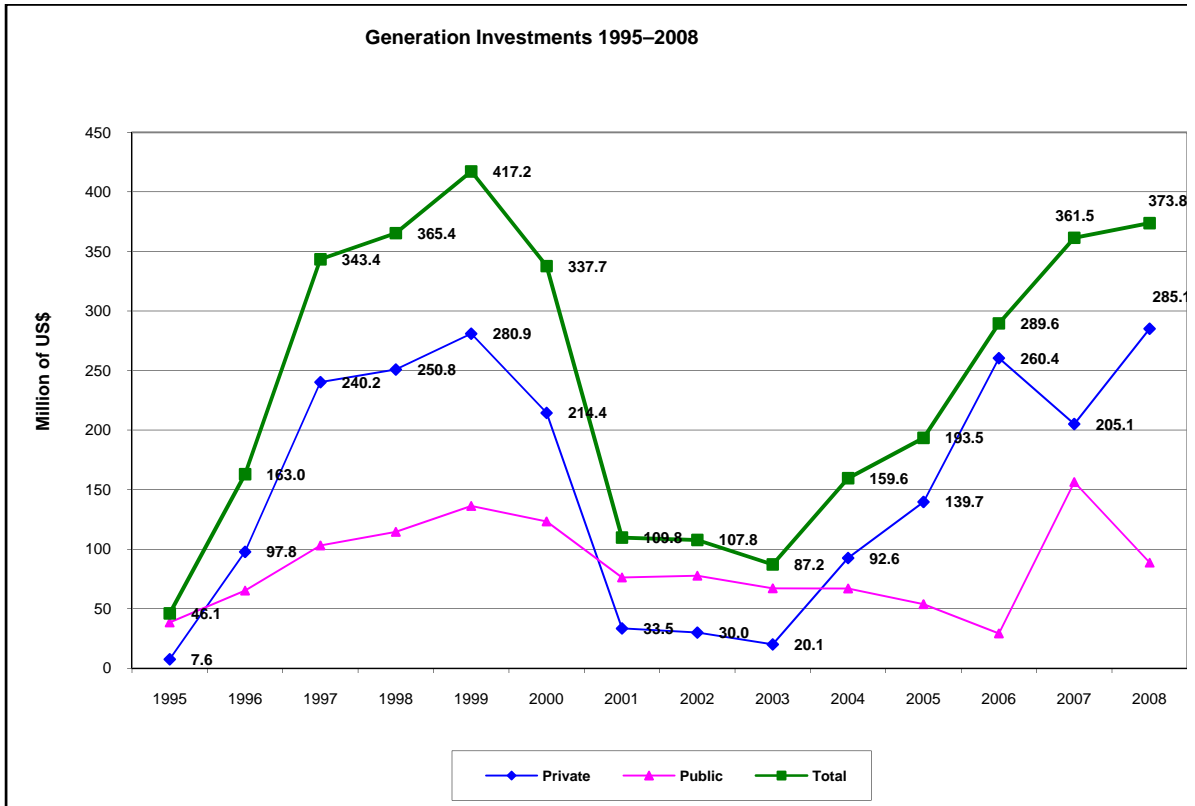
264. Electricity investments increased steadily during the initial years after the reform of the sector in 1991–92, reaching a peak of about US\$760 million in 1999. Thereafter, investments started to decrease until reaching a bottom low of US\$236 million in 2003. For example, the average annual generation investments during 1995–2000 was US\$280 million (of which 62 percent came from the private sector), two and a half times more than during 2001–04 (only US\$116 million, of which 38 percent came from the private sector). Although annual investment in generation recovered since 2004, the damage has already been caused by the delay in the implementation of required new power plants. Figure 6.7 shows generation investments during 1995–2008, provided by the public and private sectors.

265. The most important private sector investments in generation, in the last five years, have been in new gas-fired thermal plants. In contrast, after the construction of the hydroelectric plants Yanango (42.8 MW) and Chimay (142.2 MW) in 2000, which represented an investment of around US\$160 million by Edegel, no other midsize hydro plant has been built since then by the private sector.⁸⁷ The public sector investments in hydro generation were the reconstruction of the Macchu Picchu power plant (90 MW) in 2001 and the construction of Yuncan (133.5 MW) in 2005, which was sold in 2006 to the private sector.

⁸⁶ Decisions on commitments to export energy under long-term agreements should be consistent with the national interest and, therefore, should avail the support of sound central planning efforts. Export volumes of a specific project cannot be estimated by the project's feasibility studies since these do not necessarily reflect the interest of the exporting country.

⁸⁷ Private investors also developed three small hydro plants during this period: Poechos I (15.6 MW) in 2004, and Santa Rosa I (1.5 MW) and Santa Rosa II (1.2 MW), in 2005 and 2006, respectively.

Figure 6.7: Public and Private Generation Investments, 1995–2008



266. Investment in the transmission system has always been a low percentage of total investments in the energy sector, representing only just over 10 percent (in 2008, transmission investment was US\$45.7 million, 10.7 percent of the total of US\$424.7 million). This low level of investment in transmission, for a relatively large country and with a very difficult topography, is insufficient to guarantee a secure electricity service. Only the central western part of the country (where the main thermal generation and load centers—and the capital city Lima—are located) has a relatively adequate transmission system. The north and south regions of the country are interconnected with weak transmission links with insufficient capacity and reserve. This situation has a negative impact on hydropower development, considering that its locations are usually far from load centers.

267. Considering the high growth rate of electricity demand in recent years (about 8 percent in the last two years), considerable investments in electricity infrastructure are needed to follow suit and to avoid supply restrictions. Even if the growth rate slows to a more moderate level of 6 to 7 percent (in line with the expected reduction of the rate of economic growth of the country), new generation capacity of about 400 MW per year will be required during the next five years. This means that no less than about US\$1.7 billion of new investment in generation is required in the next five years (a minimum of US\$340 million annually). The annual average investment in generation during 2004–08 was US\$275.6 million.

6.6 Issues and Government Reactions

268. **Interventions in the regulatory system.** Although the Government reacted quickly to some of the short-term problems in the sector, by way of specific changes to the existing legal framework, these interventions have introduced a series of measures with wide impact on system operations and electricity prices/tariffs. For example, Emergency Decree N° 037-2008 of August 21, 2008, allows publicly owned sector companies to acquire necessary generation capacity to avoid power cuts, following a procedure outside of the established regulatory framework. In addition, to move faster in promoting hydroelectricity, MEM is using the ad hoc bidding mechanisms of ProInversión, the state agency for promoting private investment, instead of the auctions system of the electricity law. Finally, the economic and financial impact of all these measures will be transferred, directly or indirectly, to electricity consumers.

269. While it is recognized that it was necessary to address the mounting problems of the sector, it is not clear whether the recent measures introduced by the Government will have the desirable impact in the short term. Also, there is a risk that these measures could render inefficient economic solutions and also introduce undesirable long-term side effects in the general legal and regulatory framework of the sector.

270. **Price distortions in the sector.** The main signal for the supply and demand response in a market is the price of the good or service being traded. Even in imperfect markets like electricity, its price constitutes the most important reference in making decisions on investments and consumption. Before the regulatory change in 2006, generators complained that the main source of the price distortion in the electricity market was the inherent regulatory “discretion” in establishing administratively the generation tariff to the regulated market, resulting in a relatively low generation tariff, unattractive for new investments.

271. Although the regulations prior to 2006 established that the generation tariff could fluctuate inside a band of only plus or minus 10 percent of the free market prices, most of the free-negotiated supply contracts were linked, directly or indirectly, to the regulated generation tariff. So, in practice, instead of following the free-negotiated electricity price, suppliers preferred to use the administratively determined tariff as a reference price. Contrary to the economic logic, the mining sector (comprising the larger electricity users in the country) negotiated in some cases electricity prices at levels higher than other “smaller” large users. Although self-generation is an alternative to large users, it is not an economically viable option under normal conditions; therefore, electricity suppliers have some market power in their negotiations with “free” users.

272. The market of large users, which represents about 50 percent of total electricity demand, has not provided the necessary linkage, and served as the guiding signal in determining the generation tariff for the regulated retail electricity users. Somehow, this “failure” of the model (or failure of the market participants to respond as expected by the model) has contributed to the drastic change in the market design introduced in the 2006 law through the auction system. The regulatory change was triggered by the persistent

complaint of generators about the low generation tariff. Given the current and short-term situation, the new auction system is no guarantee of new investments in generation. Somehow, the market of large users, which are mainly in the mining sector, could be part of the solution for investment in new generation, in particular in hydropower, a technology with traditional links to mining.

273. As mentioned elsewhere in this report, a major price distortion in the sector is the natural gas price for power thermal generation, which has grown very fast and now represents 32 percent of total generation. This distortion is the result of the application of a special internal price different from (lower than) the economic value of gas, if compared to its substitutes or alternative uses. The use of this relatively abundant indigenous source of energy is a policy priority of the country, considering that the auctioning for the exploitation of the main field in Camisea, and, later, the contractual renegotiations, allowed a discounted internal price for all types of consumption and, in particular, for power generation. It is understood that MEM's policy is to maintain this promotional internal price at least for the period stipulated in the renegotiated contract with the producers (which allows for no more than a 5 percent increase in the price of natural gas annually, and not larger than the percentage increase of liquid fuels). This price policy applies to the initial fields of Camisea (known as lots 48 and 55), which account for a great part of the gas used in Peru. Any other exploitations or natural gas fields in the same area of Camisea or in other places are not subject to this price policy.

274. **Planning, security of supply, investments, and the role of the “market” in sector development.** The sector reform of the 1990s defined the role of the public sector as constrained to regulation and monitoring/supervision of the energy sector. Although planning was still a function of MEM, this was reoriented as a “referential” policy, stripping out any previous character of “mandatory.” The result was the production of a periodic “Referential Plan” document in which the dynamics of private participation/decision in new investments was not properly addressed. Clearly, this referential plan was of limited value to sector stakeholders, considering that most investment decisions were in the hands of the private sector. The new electricity legal framework established in 2006 reintroduced mandatory transmission planning as a “public” function of COES, the independent network operator, but also expanded the role of the “private” market in generation through the introduction of an electricity supply auction system.

275. Therefore, the current legal framework of the sector is a combination of a publicly mandated transmission planning and a (private) market approach regarding generation expansion. How this mixture would play in practice is uncertain, considering that by its very nature, electric power expansion has to deal simultaneously with generation and transmission. In the particular case of hydropower, this interrelation is more important, given that in many cases the cost of transmission for hydropower could be the economic or financial dealmaker or breaker of a project.

276. Electrical power supply is a complex system, not only from an engineering perspective, but also from an economic and regulatory point of view. There is a

fundamental tradeoff between the use of competition and regulation in order to provide cost-efficiency and at the same time maintain the security of electricity supply. Most of the sector reforms carried out in the region, including the one in Peru, did not explicitly consider the topic of security of power supply. It was implied in the reform models that the competitive market price signals would provide the necessary incentives to expand the system, as needed, to a near optimal/economic security level.

277. A key lesson of the 15 years of reform in Latin America is that a purely market-driven expansion of generation does not resolve the extremely important issue of security of supply. Aware of this shortcoming, the Chilean legal framework established penalties on private generators in case of failure to adequately provide the necessary generation to meet demand, implicitly making the private generators responsible for security of supply. However, the electricity crisis of 1998, in which private generators refused to accept responsibility for the shortage in generation, demonstrated the weakness and inapplicability of this type of regulation.

278. The proper allocation of roles between government and private agents, and understanding the complementarity between government planning and private business operations, are key for moving toward sustainable development in any basic infrastructure sector. If the provision of electricity planning, security of supply, and the proper functioning of an imperfect power market in a country will always be the final responsibility of the sector national authorities, the sector legal framework should properly and explicitly reflect this important role. This is not the case in the Peruvian legislation, where it is evident that the State needs to play a more active role to ensure an adequate security of supply. Promoting hydropower and other renewable technology is consistent with the country's energy security objectives. Given the weaknesses identified in the current system and the challenges of the external environment, the Government's role could be strengthened in the following areas:

- **Central planning:** Strengthening central planning through better integration of generation and transmission planning, providing the basis for a strategic design of energy auctions and a sound strategy for regional integration/power trade agreements, and an economically and environmentally sound energy matrix for the country.
- **Development of hydropower:** Facilitating the development of hydropower through the strengthening of the country's hydrometric system and the update of project inventories.
- **Efficiency of consumption and investment choices:** Fostering the efficiency of consumption, and investment choices, through a cost-reflective tariff system. To this end, it will be necessary to reassess the policy of gas prices for power generation—which is threatening the sustainable development of the power sector and imposing a set compensatory measures that could further distort the incentives system—and explore the possibility of improving the pricing mechanism for capacity and transmission.
- **The energy auctions process:** Conduct an energy auctions process that does not discriminate against any type of technologies and, when necessary, consider the

- following options: (i) offer premiums or discounts that are economically rational, that is, mechanisms to correct the distortions created by an imperfect pricing system; and/or (ii) conduct technology specific auctions of bidding out individual large projects.
- **Financing:** Given the threats of the current financial crisis, explore the need for and possibility of acting as a financial intermediary in mobilizing more attractive financing or, in selected cases, as a partner in public/private associations.

279. **ProInversión and the Hydropower Auction.** ProInversión is a specialized governmental agency whose board comprises seven government ministers and is presided over by the Prime Minister. ProInversión's main role is the promotion of private investments through the transfer of existing public assets, mainly in the hands of publicly owned companies or agencies—that is, a privatization process—and the concession of infrastructure facilities in classical build, own, operate, transfer (BOOT) schemes and variants. Its main activities have been centered on the concession of transport facilities like roads, ports, and airports, activities regulated by contracts. ProInversión can sign contracts-law in the name of the Government, giving these contracts a high-level status in the Peruvian legislation.

280. By law, ProInversión can participate in the concession of infrastructure facilities in any sector, including the power sector. This recently happened, at the request of MEM (for the expansion of the transmission system), during the transition period while the planning and bidding process established by the reform Law N° 28832 is implemented. The concession and contractual conditions of these processes were coordinated with MEM and the sector regulator to ensure that the sector legal and regulatory framework is being preserved.

281. In response to some short-term supply problems, MEM recently adopted several ad hoc measures to “promote” investments in new generation. These measures include a request by MEM to ProInversión to conduct an auction exclusively for hydropower, which, contrary to its previous involvement in transmission (a regulated activity), could be controversial. A set of issues associated to this initiative require further clarification:

- Will ProInversión sign contracts-law with conditions particular to the new investors?
- Will the contracts with winning bidders be transferred to distributors?
- Will ProInversión bidding be limited (open) only to hydroelectric projects that already have a concession?
- What will be the selection criteria and will there be a megawatt limit?
- Will there be a price cap in the bidding and who will determine this cap?
- What will happen with the planned long-term supply auction being prepared by the regulator, under the rules established in Reform Law N° 28832 of 2006 and its regulations?

6.7 Conclusions

282. The supply difficulties of 2004 were—aside from the hydrological problems—the symptoms of an increasing uneasiness on the part of the private sector, which complained of “low unattractive” electricity prices set by the regulator that prevented investments in new generation and transmission. These difficulties forced the sector regulatory reform of 2006 (Law N° 28832) that introduced a major conceptual shift in the pricing policy for generation and transmission, from economic cost-based regulated tariffs to an auction- and bidding-based price pass-through system.

283. The regulatory system is currently in a transition period until all regulations of Law N° 28832 are developed, approved, and implemented. Although the general regulations and procedures of the long-term supply auctions have already been approved by MEM and OSINERGMIN (in December 2008), only short-term auctions have been implemented. These auctions have not been satisfactory. The main reason explaining the weak response of generators appears to be the lack of adequate price incentives, since price caps are set at levels close to the regulated tariff. It is likely that future auctions, under the permanent regulations for long-term contracts, could confront similar difficulties if current deficiencies of the regulatory framework are not corrected.

284. In the coming years, the Peruvian energy sector will face a difficult challenge to cope with a rapid demand growth and the necessity of taking a fresh look at sector structure and the market model. An indication of the gravity of the problems is that, for the first time since the sector reform, electricity service is suffering from power cuts of significant magnitude due to congestion in the transmission system, capacity limitations in the Camisea gas pipeline, low hydroelectric generation, and lack of adequate reserve, all problems that require urgent attention. This situation will persist until new generation comes on line, which is not expected until mid-to-end 2009.

285. If no new gas supply is available, or it is limited, natural gas-fired thermal generation will peak during 2012–14 at about 2,200 MW to 2,800 MW. Any additional required generation would have to come from other sources, mainly hydropower, if possible. Therefore, a successful auction process for hydropower plants should be considered a high priority. As explained in previous chapters, the potential of new hydropower in the next five years is about 1,000 MW to 1,200 MW. An adequate and sustained enabling framework will be needed to guarantee hydropower expansion beyond that period.

286. The Camisea natural gas price for internal use in power generation is one of the cheapest in the region. It introduces a price distortion that constitutes a serious barrier to the development of alternative generation such as hydroelectricity and other renewables. This price is also a disincentive to the efficient use of natural gas in thermal power generation, making it uneconomical to install combined cycle units. However, it is understood that the Government’s policy is to maintain this promotional internal price at least for the period stipulated in the renegotiated contract with the producers (around five years). Instead, the Government is embarking on a policy of incentives for renewable

energy (premiums, exclusive auctions, tax incentives) with the aim to counterbalance the effect of the low gas price. These measures imply a departure from an efficiency pricing policy and cast doubts on its efficacy and sustainability.

287. Under the threat of an eventual natural gas shortage, MEM has established a priority order for its use, maintaining the existing contractual obligations, mainly the liquefied natural gas export contract to Mexico. First priority use is given to residential consumers, followed by compressed natural gas for transportation and then for power generation (for combined cycle first, and then for open cycle units).

288. The current auction system for long-term contracts poses the following challenges to hydropower:

- Although the regulations of the Peruvian auction system do not discriminate against any particular technology, some stipulations could impact hydro or thermal generation differently. A main constraint for hydropower plants is the anticipation period of three years required to call for bids, which is not consistent with typical lead times of hydro plants.
- Another problem is that the auction system deals with risks in an uneven manner. While in hydropower most risks are borne by the project developer, in thermal plants the main risk (i.e. the fuel cost) is borne by consumers. The difficulty of comparing the costs of thermal generation and hydropower casts doubts on the effectiveness of auctions where these technologies compete with each other.
- The distortions caused by the very low prices of gas for power generation could be addressed by the introduction of a system of discounts or premiums when thermal and hydropower are expected to compete in a single auction. This poses the challenge of setting the correct level of discounts without incorporating new distortions into the market. An economically efficient discount for hydro at the auction should be set taking as a reference the avoided cost of an equivalent thermal plant, calculated at the economic cost of gas. That is, the discount should constitute a mechanism to correct the distortion created by the gas price. The need for an efficient design and management of auctions exclusive for hydro, and/or the implementation of discounts for hydro and/or project-specific auctions, suggest that a centralized auction scheme, with the important contribution of a sound central planning effort, would be more suitable than the current decentralized system.
- Hydropower faces inherent difficulties in competing with other technologies, particularly thermal generation, since its effective capacity and energy production are probabilistic values. A sound bidding strategy for hydropower should aim at offering a firm energy price competitive with equivalent base-load thermal generation while seeking additional revenues from its secondary energy and effective capacity.

289. Given the complexities of non-technology specific auctions mentioned above, that is, the difficulties in comparing technologies with different costs and risks profiles, the existence of some regulations that are technology biased and the challenges posed by a

complex system of premiums and discounts, it would appear justified to hold separate auctions for different technologies. In this case, the power mix would be the result of a strategic approach to the expansion of the sector –supported by a sound planning exercise- rather than the outcome of an auction system marred by potential distortions and uncertainties.

290. Project-specific auctions are desirable for large hydropower projects, since they have the potential to reduce costs considerably. Such an approach would help incorporate efficiency incentives in the preparation and implementation of large projects while keeping price caps consistent with the economic cost of the proposed plants.

291. If the provision of electricity planning, security of supply, and the proper functioning of an imperfect power market in a country will always be the final responsibility of the sector national authorities, the sector legal framework should properly and explicitly reflect this important role. This is not the case in the Peruvian legislation, where it is evident that the State needs to play a more active role to ensure an adequate security of supply. Given the weaknesses identified in the current system and the challenges of the external environment, the government’s role could be strengthened in the following areas:

- **Central planning:** Strengthening central planning through a better integration of generation and transmission planning, providing the basis for a strategic design of energy auctions and a sound strategy for regional integration/power trade agreements, and an economically and environmentally sound energy matrix for the country.
- **Development of hydropower:** Facilitating the development of hydropower through the strengthening of the country’s hydrometric system and the update of project inventories.
- **The tariff system:** Fostering the efficiency of consumption, and investment choices, through a cost-reflective tariff system.
- **Financial:** Explore the need for and possibilities of acting as a financial intermediary in mobilizing more attractive financing or, in selected cases, as a partner in public/private associations.

292. ProInversión’s direct involvement in a hydropower auction raises questions about the effectiveness of the process itself and its coordination with the concessions system established by the current legislation of the power sector. Such questions should be addressed in close coordination between MEM and OSINERGMIN.

7. CONCLUSIONS AND POLICY RECOMMENDATIONS

7.1 The Potential Contribution of Hydropower in Peru

293. This assessment of the potential contribution of, and barriers to, the development of hydropower in Peru arrives at the following conclusions.

294. **While the financial crisis may cause a temporary slowdown, the Peruvian energy sector will face a difficult challenge to cope with rapidly increasing demand.** An indication of the gravity of the problems is that, for the first time since the sector reform, there have been significant power outages due to congestion in the transmission system, capacity limitations in the Camisea gas pipeline, low hydroelectric generation, and lack of adequate reserve, all problems that require urgent attention. This situation will persist until new generation comes on line, expected in late 2009. If no new gas supply is available, or it is limited, natural gas-fired thermal generation will peak during 2012–14. Accordingly, an important part of the additional generation would have to come from other sources, mainly hydropower.

295. **The technical assessment concludes that there are hydropower projects in western basins (more than 1,000 MW) with definitive concessions that are technically sound, could start construction shortly and, if so, could be commissioned by or around 2013–14.** The preparation of these projects, mostly low impact run-of-river, is supported by good basic information and capable national expertise. In fact, these projects, plus others of similar characteristics that are currently in an earlier stage of preparation, constitute one of the main options available to the country for developing a low carbon economy.

296. **A set of hydropower projects with temporary concessions (adding an additional 4,300 MW) could contribute to meeting power demand from 2015 onward.** In addition, the potential for development of hydropower in eastern basins surpasses the country's power requirements and offers an opportunity for export to neighboring countries. However, the knowledge of this potential is less advanced and the social and environmental consequences are greater.

297. **The impact of climate change on hydropower is uncertain, but a preliminary assessment of the impact of the glaciers' recession suggests that this could be limited.** There are a limited number of projects that feed significantly from glaciers, and adaptation measures can be adopted in such cases. While there are tangible measurements of the impact of climate change on receding glaciers, the scientific community has yet to adequately understand what appears to be the main impact: the impact on rainfall patterns.

298. **The economic analysis concludes that hydropower is an economically viable option for power expansion in Peru, when gas is valued at its economic cost.** In the sample of projects with definitive concessions, about 1,000 MW are economically viable

if gas is to be valued at an economic cost of around US\$4.4 per million British Thermal Units (mmBTU) (for a long term scenario characterized by crude oil prices of US\$75 per barrel). Compared to gas-based projects, the economic cost of hydrogeneration is about US1 cent per kilowatt-hour (1¢/kWh) cheaper, implying a savings of around US\$50 million per year if these projects are implemented.

299. **However, at the present very low price of gas (US\$2.14/mmBTU), few hydro projects would be financially competitive.** While an exceptionally good hydropower plant could be marginally competitive, if compared to the results of the latest energy auctions, only one project is being implemented by an industrial consortium (through commercial financing) as a hedge against future supply disruptions, rather than as a profitable venture to supply the local market.

300. **For long-lived, capital-intensive investments, like hydropower, longer-loan tenors are vital to bring down electricity prices.** Financial energy prices show great variation by financing structure: for a typical project, the price variation between commercial finance with balance sheet financing and one with International Financial Institution (IFI) participation is from US5.52¢/kWh to US4.11¢/kWh, respectively. Because of their longer-term loans, IFIs could have an important role in bringing down the costs of financing hydro projects, even when blended with shorter-term commercial loans, and in making hydro competitive even under the current very low gas prices.

7.2 Barriers to the Development of Hydropower

301. The study identified the presence of a set of barriers and potential factors impeding a satisfactory development of hydropower. These barriers are evidence of the lack of coherence in the current strategy to promote hydropower.

302. **The Camisea natural gas price for power generation, one of the cheapest in the region, introduces a price distortion that is a serious barrier to hydroelectricity and other renewable technologies.** This price is also a disincentive to the efficient use of natural gas in thermal power generation, making it uneconomical to install combined cycle units. It is understood that the Government's policy is to maintain this promotional internal price for at least the five-year period stipulated in the renegotiated contract with the producers. Instead of adjusting the gas price to create a level playing field for other technologies, the Government is embarking on a policy of incentives for renewable energy (premiums, exclusive auctions, tax incentives) to counterbalance the effect of the gas price distortion. These measures imply a departure from an efficiency pricing policy and cast doubts about its efficacy and sustainability.

303. **However, the current very low price of gas is not sustainable and, most probably, gas prices will need to increase in the long run.** With further expansion of gas-based projects constrained by capacity limits of the Camisea field and pipeline, new gas-fired plants will face the higher production costs of other fields and the economic costs of either additional pipeline capacity or, were the gas plants sited at the gas fields, the corresponding cost of additional transmission capacity to the main load centers.

304. **Financing capital-intensive projects, such as hydroelectric plants, is likely to be particularly difficult in the near future because global financial markets are in disarray.** Interest rates and liquidity positions keep changing rapidly. A normal situation for financing of new projects is not likely to be achieved until the toxic asset problems of major banks are resolved and the global economy resumes economic growth, something that is not likely to occur until 2010, or later. While unusually high spot market conditions in late 2008 encouraged the expectations for hydropower development, it is unlikely that these will be maintained in the medium term or that they would be sufficient to enable financing hydroprojects in current conditions.

305. **The regulatory system is currently in a transition period until all new regulations of Law N° 28832 are developed, approved, implemented, and tested.** Although the general regulations and procedures of the long-term supply auctions have already been approved, only short-term auctions have been implemented. These auctions have not succeeded in mobilizing expected electricity supply. The main reason appears to be the lack of adequate price incentives, since price caps are set at levels close to the regulated tariff. It is likely that future auctions, under the permanent regulations for long-term contracts, could confront similar difficulties if current deficiencies are not corrected.

306. **The current auction system for long-term contracts poses a set of constraints to hydropower that would justify separate auctions for different technologies, or even auctions of large hydropower projects.** The constraints in the current auction system include the difficulty of objectively comparing the costs and risks of thermal and hydro, a required anticipation period of three years that is inconsistent with the nature of hydropower, and the challenge of setting premiums or discounts that do not incorporate economic distortions. The current hydropower auction by ProInversión was initiated in recognition of the deficiency in the auction framework. While this is clearly an exceptional case outside of the normal electricity sector regulatory framework that may not be required in the future, its design is considered correct.

307. **The process of obtaining concessions and permits, subject to frequent changes brought in by legal reforms, is seen by developers as unpredictable and excessively long.** The complex nature of hydropower implies the participation of a high number of players in the process of project concessions and permits. It is perceived by most stakeholders that the density of the process and frequent changes mandated by legal reforms make it unpredictable and excessively long. In particular, the legal framework regulating water rights and rights of way has major voids and constitutes a barrier to the development of hydropower projects. Also, the relatively early award of definitive concessions—that grant exclusivity rights—is proving to be an inefficient measure that often impedes the development of an attractive site (when owned by a weak developer) and hampers competition.

308. **The weakness of the framework for environmental and social assessments threatens the prospects for a sustainable development of hydropower, especially in the eastern basins that are likely to affect indigenous people.** While environmental assessments for power projects have been prepared since the mid-1990s, there is still a set

of problems to overcome, together with the inherent conflict of interest of the Ministry of Energy and Mines's (MEM's) role as both promoter and regulator of projects. Key problems include the quality of environmental studies, weak consultation processes including with indigenous peoples and other local populations, and the absence of a proper framework to address social issues, including the lack of an effective benefit sharing mechanism that acknowledges the peoples that are directly affected.

7.3 Recommendations for a Coherent Strategy in Support of Hydropower

309. Overcoming existing barriers will require a fresh look at sector policies, including revisiting the role of the State as policymaker, regulator, and promoter. The Government has stated its support for the development of renewable energy—particularly hydro and wind power—to meet its objective of ensuring an adequate supply of electricity consistent with energy security and environmental objectives. Such a strategy has the potential of making an important contribution to coping with the rapid growth of demand for electricity through the provision of a competitive and reliable source. However, the barriers outlined above are evidence of gaps in the coherence of this strategic approach.

7.3.1 Stronger Role of the State is Essential

310. A key lesson of the reform in Latin America is that a purely market-driven expansion of generation does not resolve the extremely important issue of security of supply. Most of the sector reforms carried out in the region, including the one in Peru, did not explicitly consider the topic of security of the power supply. It was implied in the reform models that the price signals of the competitive market would provide the necessary incentives to secure an economic security level. However, experience has proven that this was not enough, and that some sort of government intervention is necessary.

311. In Peru, the State needs to play a more active role to ensure an adequate security of power supply. The proper allocation of roles between government and private agents, and understanding the complementarity between government planning and private business operations, is key for moving toward sustainable development in any infrastructure sector. If the provision of electricity planning, security of supply, and the proper functioning of an imperfect power market in a country will always be the final responsibility of the sector national authorities, the sector legal and regulatory framework should explicitly reflect this important role. This is not the case in the Peruvian legislation.

312. Given the weaknesses identified in the current system and the challenges of the external environment, the Government's role should be strengthened in the following areas: (a) sector planning and the provision of basic information, (b) pricing policy, (c) project concessions and licensing, and (d) financing of projects.

Sector Planning and Basic Information

313. Strengthening central planning through a better integration of power generation and transmission planning and natural gas strategic planning will be key to enhancing hydro development and for achieving a sustainable energy matrix.

Planning provides valuable information for the strategic design of energy auctions, especially where the promotion of hydropower is desirable. In particular, it is useful in assessing discounts and/or premiums, the energy demanded in each auction, and anticipation periods. Sector planning also provides the basis for a sound strategy for power trade agreements/regional integration, for assessing the optimal share of energy from the country's perspective, and for an economically, socially and environmentally sound energy matrix for the country. The experience of Brazil in strengthening the country's planning capacity in energy could be a useful reference.⁸⁸ In Peru, this effort should be tailored to the country's needs (i.e. an strategic approach for the expansion of the energy sector, the integration of power and gas, analytical inputs for a better design of energy auctions), identify clearly institutional responsibilities and allocate adequate resources.

314. An important element for both sector planning and project preparation is the strengthening of the hydrometric system and the update of project inventories.

A sound design and economic assessment of a hydropower project relies heavily on the quantity and quality of basic information, particularly on hydrological data. To such end, it is necessary to have historical records of river flows, at the project site, of at least 5 years (ideally 10) –and maintain stations as long as possible- complemented by hydrometric data of adjacent basins and meteorological information of the region involved.

315. The role of the Government in preparing projects—that is, carrying out feasibility studies—should also be considered. However, the decision to engage directly in such a demanding activity should be taken only after a thorough assessment of market conditions is completed since it would appear that, to a great extent, the private sector has the capacity and resources to assume this pre-investment risk.

316. Since there is still a great deal of uncertainty about what will actually happen as a result of the climate change process, it is essential to monitor closely the progress in this area and, in particular, in the understanding of rainfall regional patterns in order to incorporate this knowledge into the design of hydropower plants and the formulation of a power supply strategy for the country. The studies mentioned in the introduction to this annex are important first steps in this direction

⁸⁸ In response to the supply crisis of 2001-2002, the Government of Brazil decided to establish the Empresa de Pesquisa Energetica (EPE), now a one hundred professionals strong public agency responsible for energy planning and for providing the analytical input required in the formulation of sector policies and key strategic decisions.

Pricing Policy

317. **Fostering the efficiency of consumption and investment choices depends on a policy of energy prices that reflects economic costs.** Excessively low gas prices threaten the sustainable development of the power sector and have motivated a set of compensatory measures that could be further distorting the incentives system. From the perspective of efficiency and environmental protection, the most desirable policy response is to price gas at its the economic value rather than at its financial cost. This could provoke the objection that a gas price increase is politically unacceptable. However, as stated above, it should be acknowledged that the current level of gas prices for power generation will not be sustainable in the future and, hence, it will be necessary to revise the current pricing policy. Whichever the impact of such adjustment on electricity tariffs, poor consumers with low levels of consumption would experience a much smaller impact because of the Electricity Compensation Fund (Fondo de Compensación Social Eléctrica, FOSE) equalization.

318. **It is necessary to revise the methodology for estimating capacity payments and the conditions for such payments,** in order to yield adequate values and a correct incentive system. The current system, based on data of open cycle turbines over the past five years does not reasonably reflect the capital cost of building a new project.

Energy Auctions

319. **Overcoming the barriers from energy auctions could be possible through three alternative courses of actions.** The current auction system poses a set of constraints that could be overcome by developing: (a) an auction system where all generating technologies compete, (b) an auction system exclusively for hydropower projects, or (c) an auction system of large hydropower projects.

320. **An auction system where all generating technologies compete for long-term energy contracts could be a viable alternative.** This is the current system under the 2006 Electricity Law, although the incorporation of compensation mechanisms is not factored into its design. If the Government decides to proceed with auctions where all technologies compete, which creates some difficulties in comparisons among technologies, factors to consider are:

1. An economically efficient discount for hydro should be set in relation to the avoided cost of an equivalent thermal plant, calculated at the economic cost of gas. That is, the discount should constitute a mechanism to correct the distortion created by the gas price.
2. Revising the anticipation periods to call for bids requiring longer anticipation periods consistent with the nature of hydropower and other longer lead-time technologies. This is currently a main barrier for hydropower plants, since the anticipation period of three years is not consistent with typical longer lead times of hydro plants.

321. **However, holding auctions exclusively by technology, including hydropower, is more feasible since it overcomes the inherent difficulties of comparing technology costs in an objective manner.** The adoption of a policy of separate auctions for hydro projects, where they compete in covering a specific demand (a target for hydro expansion optimized through a central planning exercise) is recommended.

322. **Project-specific auctions for large hydropower projects could reduce costs considerably, especially for projects such as those being studied with a view to export to Brazil.** Such an approach would help in incorporating efficiency incentives in the preparation and implementation of large projects while keeping price caps consistent with the economic cost of the proposed plants.

Project Concessions and Licensing

323. **While current legislation establishes temporary and definite concessions for hydropower, it is likely that awarding definite concessions at a more advanced stage and revising the open-ended nature of concessions would be beneficial.** Important areas that merit a review of the current concession system are:

1. The need to award definitive concessions at a more advanced level of preparation or, preferably, after a competitive process for the project has been held (that is, avoiding exclusivity rights that could hamper competition and, consequently, a more efficient process); and
2. Revising the indefinite, open-ended, nature of definitive concessions with a view to introducing a termination or extension under conditions to be agreed upon.

324. These two points are of great importance when dealing with large hydropower projects, such as those being prepared with the view to export electricity to Brazil, since incorporating competition into a project that has been prepared by a single group has the potential of yielding considerable economic benefits to the country.

325. **Prior environmental licensing should be a requirement for a project to participate in an auction.** This implies an earlier environmental clearance—prior to the award of the definitive concession—in order to reduce the uncertainty of project completion after the auction is held.

326. **Establishing an effective benefit sharing mechanism for hydropower development could help mitigate potential environmental and social impacts.** An effective benefit sharing mechanism associated to the use of water would help align the interests of affected local communities, including indigenous peoples, and project developers and, thus, help develop local communities and strengthen relationships among the State, the community, and the project.

327. **From an environmental standpoint, it is essential to improve the environmental and social assessments for hydro development, including impacts on indigenous peoples and other local populations, and the compliance with an open**

and legitimate consultation process. Specific measures are independent auditing, adequate budgeting, establishing clear and minimum requirements for the studies and proper coordination of studies in the same river basins and work toward formulating and implementing a social agreement (see Chapter 5, par. 197). Given the fragility of the ecosystems in the Amazon basins and the vulnerability of social groups that can be affected, it is imperative to ensure the legitimacy and openness of consultation processes for these projects.

Financing of Projects

328. **Explore the need for and possibilities of the Government to act as a financial intermediary in mobilizing more attractive (IFI) financing and/or, in selected cases, participate in public/private associations.** Given the current financial crisis, it is likely that normal financing of new projects would not be achieved until the toxic asset problems of major banks are resolved. Also, the mobilization of longer-tenor IFI financing could considerably reduce the cost of generation expansion.

7.3.2 Development of the Amazon Basins for Exports to Brazil

329. **The hydropower development of the eastern basins of the Andes constitutes one of the main challenges of the power sector in the medium to long term.** Its satisfactory development offers large economic benefits and will rely, to a great extent, on the implementation of a strategy that guarantees an adequate level of competition while protecting a fragile environment and the well-being of the populations that will be affected.

330. A strategy for development should include two main, and equally important, objectives;

1. **Sustainable development based on the adoption and implementation of international standards for social and environmental safeguards;** and
2. **A competitive process aimed at maximizing economic benefits to the country.** This process should include auctions for projects prior to the award of definitive concessions. To this end, a strong technical assessment of projects, led by government agencies, is needed to break the asymmetry of information inherent in large projects.

331. For the program of exports to Brazil, these main objectives should be complemented by a sound and balanced legal framework comprising an intergovernmental agreement between Peru and Brazil and concession agreements between the Peruvian State and each project developer.

332. **Important aspects to be included in the intergovernmental agreement are:**

- **A statement of common objectives**—economic, social, environmental.

- **A commitment of the two countries to abide by international standards for environmental and social safeguards**, including an open consultation during all phases of project preparation and implementation.
- **Agreement on the principle that the sharing of energy should be balanced** between the two countries. A negotiated share should be based on the results of power system planning exercises of both countries, thus reflecting the national interests and the specific needs of each region (not from studies carried out for specific projects). Also, the agreement should include a provision for flexibility in time.
- **Agreement on the principles for an auction/competitive process** for awarding definitive concessions. This should include the criteria for eligibility of bidders and the selection of bids and ceiling price.
- **Agreement on technical cooperation** between the two countries to achieve better and more transparent knowledge of the project and facilitate competition—for example, to address specific technical risks prior to the auction.
- **Basic conditions for Power Purchase Agreements (PPAs)**; ideally, adoption of a model contract for a build, own, operate, transfer (BOOT) arrangement with a concession expiring after 25 years (a common international practice).
- **Principles for commercial and operational rules**; including issues associated with the sales of firm and secondary energy (access to spot markets), capacity payments, the compatibility of both systems, and provisions for an eventual integration of both systems. The option of two technically separated plants⁸⁹ should be discussed on a project-by-project basis.
- Inventory of projects should be subject to an **environmental and social screening** carried out by the Peruvian side.

333. **Important aspects to be included in concession agreements for each project** (to be signed after the bidding process) are:

- Clear definition of the **rights and obligations** of the host country and the project developer;
- **Commitment to follow international standards for environmental and social safeguards**, as established in the intergovernmental agreement;
- **Agreement on the role and powers of oversight groups**; that is, panels of experts comprising highly skilled international experts;
- Definition of **budget** (and projects commitment) to address social and environmental program;
- Commitment of the project to effectively address **unanticipated impacts**, and to fund them; and
- Specifics of the **tax regime**.

⁸⁹ That is, two plants that share basic upstream structures, such as intake and/or reservoirs, but have separate generating facilities (penstock, electro-mechanical equipment, transmission) that allow them to operate independently.

Annex 1: Impact of Climate Change on Hydropower

1. An important dimension to consider in the preparation of hydropower projects is the impact of climate change on their effective operation and, hence, on their design and estimates on energy production and effective capacity. A great deal of uncertainty surrounds the impact of climate change. This uncertainty stems from the difficulty in forecasting the nature, intensity, and timing of the climate change process and, in particular, its likely regional impact on rainfall patterns, mountain wetlands, and the retreat of glaciers. In assessing the impact of climate change on hydropower and other water use activities, it is important to establish the time horizon of this impact. While climate trends and the pace of warming in the mountain areas in the Andes region are now becoming better documented (Bradley, 2006, Ruiz, 2009), there remains uncertainty over impacts on rainfall and consequently run offs. Still, the evidence indicates that a substantial temperature increase is expected over time, with temperature variations now estimated at between 0.2 to 0.5 degrees per decade. These changes will happen over time and their effect will be cumulative. While the pace of change is not yet known, indications are that the immediate effects of climate change are not likely to affect hydropower investments with their economic life of 30 to 40 years. However, even within this time frame, it will be important to factor in uncertainty related to climate change. It is strategically even more important for Peru to anticipate these consequences in national energy planning.

2. Of the utmost importance is the possible impact on rainfall patterns, since hydropower generation is directly related to the volume and seasonal distribution of rainfall. Depending on the regions and the models consulted, this impact could be either positive or negative. Intergovernmental Panel on Climate Change (IPCC) reports⁹⁰ are not conclusive in this respect. On the other hand, it is likely that evaporation rates will increase and this needs to be accommodated in the estimate of run offs. Also, there is an expectation that stream flows will in general, increase its seasonal variability over time and this should also be considered in medium and long term planning exercises.

3. Specific climate change trends in the Peruvian Andes include:
- A continuous retreat of tropical glaciers –faster in smaller glaciers- that will reduce their natural water storage capacity.
 - A likely increase in atmosphere temperatures and reductions in relative moisture, which would affect net transfer of moisture from atmosphere to soil and thus natural water storage
 - A possible reduction in precipitation in the central-southern South American continent, affecting the south of Peru, as well as regions of Bolivia, Chile and Argentina.
 - Greater volatility in the availability of water associated to a possible increase in the frequency of the El Niño phenomenon, which would increase the volume of precipitation in the north of Peru while reducing it in the south.

⁹⁰ IPCC, “Fourth Assessment Report,” 2007.

4. A parallel World Bank initiative, conducted with the support of ESMAP and the collaboration of the Ministry of Energy and Mines, aims to investigate the impact of climate change on mountain hydrology in Peru. The study is titled “Assessing the Impacts of Climate Change on Mountain Hydrology—Development of a Methodology through a Case Study in Peru”. Its objective is to demonstrate a methodology to assess the impacts caused by climate impacts (rapid mountain warming, with the consequent changes in glaciers and mountain wetlands, and change in rainfall patterns) on Peru’s hydrology.

5. This study is expected to provide additional information for hydropower planning in Peru in the long-term through the following components:

- a. Climate component: Use of outputs from the Earth Simulator⁹¹ and the Community Climate System Model, CCSM⁹², from the United State’s National Center for Atmospheric Research (NCAR), for a selected scenario to assess net impacts in precipitation and temperature over the watersheds in the Andes of Peru. The objective of this component is to provide likely scenarios of future climate for mid and end of century in Peru, capable of producing environmental parameters to be used as inputs for hydrology modelling. The use of the results from the Earth Simulator and the CCSM will provide an overall representation of current precipitation and temperature and an estimate of likely climate anomalies by the middle and end of century.
- b. Hydrology Component. Estimate of current and projected changes in runoffs caused by increases in temperature, glacier retreat, changes in precipitation and drying of mountain wetlands for three emblematic basins in Peru: Rio Santa, Rimac and Mantaro river basins, to 2030, 2050 and 2090. The objective of this component is to develop a tool, useful to support the efforts of the Government of Peru, for the exploration of, and planning for, the impacts of climate change in the hydrologic response of emblematic watersheds. The modeling technique to be used is WEAP (Water Evaluation and Planning Tool) developed by the Stockholm Environmental Institute combined with a simulation module of the dynamic behavior of glaciers jointly developed by IRD and SEI, specifically for this task. The selection of the WEAP model is the result of a comparison exercise undertaken through the Regional Adaptation to Glacier Retreat Project (PRAA). The WEAP⁹³ was to be modified to incorporate a glacier module and

⁹¹ The Earth Simulator is a super computer. The code for the model run by the Earth Simulator was developed jointly by the Center for Climate System Research (CCSR) of the University of Tokyo and the Japanese National Institute for Environmental Sciences (NIES). The particular version of the CCSR/NIES AGCM has been used for several international modeling efforts, including future projections for the Intergovernmental Panel for Climate Change (IPCC, SRES) and the Atmospheric Model Intercomparison Project (AMIP).

⁹² The CCSM-2 released in 2002 simulates climate by dividing the world’s water and land surface into rectangular grid points that extent upward into the atmosphere in 26 vertical layers. Its resolution varies from 2.8 degrees for oceans and sea ice, to 1 degree which corresponds to approximately 100km resolution. www.ucar.edu/communications/CCSM/index.html

⁹³ The WEAP model can evaluate the hydrologic feasibility of water management options related to the storage, distribution, use, and conservation of regional water supplies (Sieber et al. 2004; Yates et al. 2004). WEAP is a microcomputer tool for integrated water resources planning. It provides a comprehensive, flexible and user-friendly

adjusted to represent Paramos and mountain wetlands. The basins (Rimac, Santa, Mantaro) were selected with GoP to reflect watersheds of major relevance to economic activity large hydropower potential and or the perceived potential of significant change in conditions induced by future climate.

6. A third activity being implemented by the World Bank that is expected to provide more information on climate change impacts on hydrology in Peru is the “Regional Andes: Implementation of Adaptation Options to Rapid Glacier Retreat in the Tropical Andes Project.”

7. Since the results of the above studies are not yet available, the preliminary analysis below is based on currently available knowledge about climate change impacts in Peru.

The retreat of tropical glaciers.

8. Special attention is being given to the impact of climate change on tropical glaciers. This process is particularly important in Peru, where approximately 70 percent of the world’s tropical glaciers are located. Measurements in most glaciers in the country reveal that they have receded dramatically during the last two decades, thus reducing the natural storage capacity that they provide and that some existing and future hydropower plants use, or will use, to increase their energy production during the dry season. The present report explores the nature of this impact taking into account the information available on each project. However, this effort is only preliminary and good deal of research is needed on the topic to: (a) better understand the role of glaciers in the hydrological cycle, (b) monitor glaciers and dry season flows of existing plants and projected hydropower plants, and (c) assess options to mitigate the impact of glaciers’ recession. Continued work is also needed on forecasting the impact of climate change on rainfall patterns on the region.

9. Subject to the yet limited knowledge on the role of glaciers as natural storage entities, and the incipient research in these matters,⁹⁴ the team explored the nature of the problem in order to gain a better understanding of its impact on current and future hydropower generation in Peru. Preliminary conclusions are as follows:

- The gradual loss of glaciers will have a considerable impact on those plants or projects where glaciers have a dominant role in the hydrological cycle. The problem is irrelevant when there are no glaciers in the watershed and less relevant when they play a minor role, say less than 5 percent of the watershed area.

framework for policy analysis. WEAP is distinguished by its integrated approach to simulating water systems and by its policy orientation. WEAP places the demand side of the equation—water use patterns, equipment efficiencies, re-use, costs and allocation—on an equal footing with the supply side—streamflow, groundwater, reservoirs and water transfers. The model can explicitly incorporate climatic change and changes in land use and other watershed conditions that control watershed response. Simultaneously, it can address opportunities for expanding the beneficial uses of regional water supplies to better satisfy an array of possible water management objectives.

⁹⁴ The parallel study on hydrology is also incorporating the effect of glaciers into the modeling of the hydrological cycle in an effort to investigate its impact on runoff and water uses.

- Only 2 of the 11 projects assessed in the sample have a glacier area that exceeds 5 percent of the watershed. Also, only 307 MW (Cañon del Pato – 264 MW and Cahua – 43 MW) of the existing 2,826 megawatts (MW) of hydro capacity installed in Peru, that is, around 11 percent, feed from watersheds where glaciers make a significant contribution. Other plants, such as Huinco (258 MW) and Callahuanca (85 MW), used to feed from glaciers that have already been lost (or almost lost). Also, in a few cases, the lost storage capacity of glaciers has been replaced by small reservoirs located in the upper basin (for example, Santa Eulalia basin upstream of Huinco and Callahuanca).
- The impact would be limited to the dry season, since all hydropower plants—existing and planned—have or will have an excess of water during the rainy season. Also, this impact would be mostly on the production of energy, not on the capacity guaranteed by the hydro plant, since most plants have, or are designed with, daily regulating facilities that usually allow them to continue operating at the peaks during the dry season, even under conditions of reduced water flows, thus reducing the economic impact. In fact, since the revenues of a hydropower plant stem from: (a) the energy it sells, and (b) the effective capacity it offers to the system, a typical plant would be affected only in its dry season energy sales. From this point of view, it could be argued that other uses, such as urban water supply or irrigation, would be more vulnerable to the impact of the loss of glaciers.
- The main area affected by the melting of glaciers would be the Santa River basin, which feeds from the Cordillera Blanca, the largest mountain range in the country and a touristic region known for its scenic beauty and outdoor recreation activities. There is evidence that some tributaries of this river basin are already showing the impact of the glacier melting process, reducing its runoff during the dry season by as much as 20 to 25 percent. For example, at the Quitaracsa River, a case where apparently low altitude glaciers have already been lost, the potential energy production during the dry season (May–December) would have been reduced by around 21 percent during the last six years. This value is used as reference for the sensitivity analysis presented in the economic chapter of this report.
- However, a review of the hydrology of 40 years for the 11 projects assessed in this study does not show a clear trend in terms of changes in river flows. Two projects reveal a statistically significant reduction in dry season flows (Quitaracsa and Santa Rita, both in the Santa River basin) while one project reveals an increase in these flows (Huanza, in the Santa Eulalia River basin) which appear to be associated to additional runoff caused by the melting of the glaciers lost in recent years.
- Project developers are planning mitigating measures to counterbalance this impact when relevant. The main solution being considered is the gradual construction of

small, high-altitude reservoirs to compensate for the storage capacity lost. These small dams will also benefit other users downstream—for example, water supply and irrigation. Some developers propose that, since this is a multisector issue, the State should intervene in its planning and, when warranted, in sharing investment costs.

- In most glacier basins, it is common to find favorable morphological conditions for the construction of small dams, since the recession of glaciers has left relatively narrow river sections where moraines are already acting as natural dams (in many cases there are lagoons).
- Preliminary cost estimates suggest that the additional investment in small dams to compensate the foregone storage provided by glaciers would increase the average energy production cost of a hydropower plant by around 3 to 4 percent. For example, for a project that would be losing around 20 percent of its energy during the dry season, it is estimated that the capital costs of high-altitude dams in favorable sites could range from US\$1 million to US\$5 million for reservoirs in the range of 5 million to 20 million cubic meters. In the case of the Quitaracsa tributary, restoring the eventual loss of 2 cubic meters per second during the dry season (equivalent to 16 to 17 gigawatt-hours (GWh)) would require an additional storage of around 35 million cubic meters, which would cost around US\$8 million. This would yield a cost of US4.9 cents per kilowatt-hour (¢/kWh) for the energy recovered. This figure should be compared to the cost of the alternative solution: buying energy from the spot market. As a reference, the production cost of a gas-fueled combined cycle plant would be US5.3 ¢/kWh (for a power plant operating at a plant factor of 75 percent and an oil price of US\$75 per barrel).

10. In summary, the consequences of warming in the Andes, reflected in the recession of glaciers, changes in evaporation rates and runoffs and possible changes in streamflows, are events that warrant further research, particularly in understanding the contribution of glaciers as natural reservoirs and the nature of the ongoing melting process. Sites where these impacts may play a significant role in the basins' hydrology should incorporate these considerations in the planning process. When relevant, preliminary estimates suggest that this impact could cause an energy loss of 20 percent during the dry season though this could vary from project to project. Two main adaptation measures have been identified: (a) the construction of small dams in the upper basins aimed at restoring the natural storage lost; and (b) compensating energy losses through energy purchases in the spot market, most likely energy of thermal origin. While the first measure would benefit all water users located downstream, the latter measure would be a solution exclusive to the power sector.

Some considerations for the future

11. It would be speculative at this moment in time to assert that there will be more or less water available in the country as a result of the climate change process. There is however growing evidence that mountain regions will warm at faster rates than

surrounding lowlands and this warming will have direct consequences on evaporation rates, runoffs and possibly, streamflows. In addition, recent studies indicate that the water regulatory capacity of mountain wetland habitats will be reduced with exposure to warmer temperatures. More specifically, early research appears to suggest that there could be more runoff in the north while the south would be affected by more severe droughts. Also, there could be greater volatility of rain patterns as the El Niño phenomenon would become more frequent. These factors, and the uncertainty surrounding them, suggest that future hydropower development in Peru should consider the following:

- Since there is still a great deal of uncertainty about what will actually happen as a result of the climate change process, it is essential to monitor closely the progress made in this area and, in particular, in the understanding of rainfall regional patterns in order to incorporate this knowledge into the design of hydropower plants and the formulation of a power supply strategy for the country. The studies mentioned in the introduction to this annex are important first steps in this direction.
- The need of a continuous increase in storage capacity to compensate for the loss of glaciers (an ongoing process as well as measures already being taken), more frequent Niño's and a possible dryer hydrology in the south of the country. It is worth noting that while these measures could compensate for losses in the south of the country, they would also help increasing the hydropower production in the north and central regions of the country as more Niño's would increase rainfall volumes thus providing a net benefit.
- Regional climate change patterns could suggest that a hydropower strategy should focus more on the northern and central regions of the country, while seeking other power supply solutions in the south (say, natural gas). However, the site specific nature of hydropower should be always kept in mind since there could be especially attractive sites in the south that would justify a sound investment.
- It is important for the energy sector to actively participate and support efforts to better understand climate impacts through improved monitoring and modeling.
- There is a need to assess the additional storage capacity that would be required to compensate for losses in water regulation of existing reservoirs, where such losses are expected to occur.

Annex 2: Recommended Measures to Strengthen the Current Hydrometeorological Network

1. This report recommends the following measures to strengthen the current hydrometeorological network⁹⁵:

- Digitalize all hydrometeorological information in the National Meteorology and Hydrology Service (*Servicio Nacional de Meteorología e Hidrología*, SENAMHI) (and possibly other agencies) not currently in electronic form (for example, water-level recorder charts, flow measurements) before it is irretrievably lost, reprocessing together with already digitized data using the latest hydrological database software (enabling extensive quality auditing, graphical control, and so forth). The priority should be (a) key stations still in operation with the longest records, and (b) river basins with good hydropower potential.⁹⁶
- Digitize all information and data on interventions, that is, regulation of lakes, reservoirs, and extractions for irrigation and potable water supply. Most of this information is available not in SENAMHI but in other central, regional, provincial, and local agencies and private companies (for example, mining). Certain basins should be made priorities.
- Arrange for sharing of hydrometeorological information obtained by private companies (for example, Independent Power Producers [IPPs], but ensure that they do not lose the right to develop the project[s] for which the measurements have been made). Given the brevity of the record available at many stations, this information is useful for regional analyses of floods and sediment and would improve project designs and sustainability prospects.
- When SENAMHI provides data to users, information on the quality of the data (frequency of observations, flow measurements, range of discharge covered, and so forth) should also be provided. This information is important for assessing reliability of flow estimates (and hence energy production and revenues), not for evaluating performance of SENAMHI.
- After thorough analysis of the current chronological and geographic data availability and locations of likely future hydropower and other water resource developments, there is a need to extend the hydrometeorological network. Priority should be given to: (a) upgrading/new networks on selected rivers of the Eastern/Amazon watershed with the view to support the development of the most promising sites in this region,⁹⁷ and (b) recently discontinued stations with long records.

⁹⁵ These recommendations are complemented by the ongoing support provided by the World Bank study “Assessing the Impacts of Climate Change on Mountain Hydrology – Development of a Methodology through a Case Study in Peru” which documenting climate changes impacts.

⁹⁶ This would be a major one-off exercise similar to the Dutch-supported “Hydrological Crash Programme” in Sri Lanka in the 1980s and the recent World Bank-supported “Hydrology Project” in India.

⁹⁷ It is estimated that the installation of a network of 15 hydrometric stations, including the required planning and operation for a period of five years would cost around US\$1 million (for water-level recordings of up to 25 meters in relatively remote areas, including stilling wells (a type of vertical wheel used to measure water levels), housing, water-level measuring and recording equipment and staff gauge, and the cost of planning, contracting, and the supervision of installation and data processing).

- The uncertainties due to climate change/glacier recession and the need for contingency plans are relevant not only for future hydropower developments but also for existing power plants.

2. Also, it would be worth assessing the potential benefit of regional studies and defining a course of action. Some impediments could be removed by the realization of regional studies of floods, sediments, low flows, and basinwide water balances, extending the work initiated by the United Nations Educational, Scientific and Cultural Organization (UNESCO) (2006) under its International Hydrological Program (*Programa Hidrológico Internacional*) for Latin America (PHI-LAC). Such studies could be conducted, with little expense, by SENAMHI (or another government agency, for example, the National Institute for Natural Resources [INRENA]) or by university research departments.

Annex 3: Avoided Cost Approach: Sample Calculation for a Typical Project

- Hydro installed capacity = 146 MW
- Annual net hydro energy at 0.606 percent load factor, less 2.5 percent transmission losses = 755 GWh
- Firm capacity = 122.5 MW
- OCCT required = 92.1 MW
- CCGT required = 30.4 MW (30.4 + 92.1=122.5)
- Net energy from OCCT = 33.3 GWh
- Net energy from CCGT = 721.8 GWh
- At US\$4.4/mmBTU, energy cost for OCGT = US4.37¢/kWh, for CCGT = US3.14¢/kWh, so average avoided energy cost US3.2¢/kWh
- Capacity benefit for OCCT = US\$76/kW/year, for CCGT = US\$139/kW/year (based on capital costs of US\$460/kW and US\$875/kW, respectively, based on 12 percent discount rate), so weighted capacity benefit = US\$123/kW/year
- Avoided cost for the composite OCCT and CCGT projects = US¢5.31/kWh.

BTU = British Thermal Unit.

CCGT = Combined cycle gas turbine.

GWh = Gigawatt-hour.

kWh = Kilowatt-hour.

mm = Million.

MW = Megawatt.

OCCT = Open cycle combustion turbines.

Annex 4: Procedures for the Licensing of Hydropower Projects

Concessions for Hydropower Projects

Temporary Concessions

1. A temporary concession⁹⁸ can be granted for up to two years, and can be renewed only once for two more consecutive years.
2. Temporary concessions can be extended. Applications for an extension of works (in cases of force majeure where more time might be needed) must be done within 30 calendar days before its ending date. The extension period can last for only two more additional years, after which the concession will cease and the guarantee bond cashed. To request an extension, the concessionaire must present a report and renew the security bond, together with a new license for water use, if needed. Extensions should be granted within 30 calendar days of submission and are published once in *El Peruano* (Box A4.1)

Box A4.1: Requirements for Temporary Concessions

- Request to the General Directorate for Electricity, and payment of 40 percent *Unidad Impositiva Tributaria* (UIT), according to what the Unified Text for Administrative Procedures establishes.
- Together with this, the petitioner needs to show proof of public registration of sponsor/developer as a commercial company according to Peruvian law and other necessary legal documents to support such claim.
- Descriptive statement and full set of engineering drawings and maps of all project installations.
- Project implementation schedule and established deadlines.
- Project costs estimation and budget.
- Specification of the rights of way needed for the study.
- Authorization for water use (currently granted by the National Institute for Natural Resources (INRENA).
- Delimitation of the area requested for concession indicating *Universal Transversal Mercator* (UTM) coordinates. It must be signed and with the professional seal of the professional in charge.
- Security bond in favor of the Ministry of Energy and Mines (MEM), in an amount equivalent to 1 percent of the estimated project costs, up to an amount of 25 UITs.

Applications must be sent to MEM, and should be granted within 30 working days of submission.

Within the first five working days, the application will be published twice in *El Peruano*, once the General Directorate for Electricity verifies that it meets all existing requirements.

⁹⁸ Temporary concessions are regulated in article 23 of the Electric Concessions Law (LEC), in its Regulations articles 30–33, and in the Unified Text for Administrative Procedures (TUPA) CEO2 Annex 1.

Definitive Concessions

3. Definitive concessions are set up for all electric energy generation plants using hydro resources with an installed capacity of 500 kilowatts (kW) and above.⁹⁹ They are required prior to project construction. Definitive concessions are given for an indefinite period and allow for rights of way to be imposed by the State.

4. Following article 26 of the Electric Concessions Law (LEC), if within 15 working days from the date of publication in El Peruano of the request for definitive concession, new applications for the same concession are submitted, the General Directorate for Electricity (DGE) will notify all interested parties within five calendar days and determine which project will be granted the concession.

5. The DGE will grant the concession to the project that best uses the existing natural resources or, alternatively, to the project that has a shorter construction time frame. If time frames are the same, the DGE will grant the definitive concession to the petitioner that had already been granted a temporary concession and had fully discharged its obligations (Box A4.2).

Other Requirements at the Local Level

6. In addition to a temporary or a definitive concession, a plant also needs a generation and transmission concession (to be able to join the system) and other local permits, such as:

- Planning and building permission, to allow construction on land.
- Permits needed at different stages for the plant's different sections (tunnels, turbines, and other civil structures).
- Other permits involving the facilities and personnel such as working permits, and compliance with health and safety regulations.

⁹⁹ Definitive concessions are set up in LEC articles 3, 6, 22, 25, and 28; in its Regulations articles 37–43, 53, and 54; in the TUPA CEO1 Annex 1; and in Executive Decree 1002 (for Definitive Concessions to Generate Electricity Using Renewable Energies).

Box A4.2: Requirements for Definitive Concessions

- A request before the General Directorate for Electricity (DGE), with proof of payment of 50 percent *Unidad Impositiva Tributaria* (UIT).
- Proof of public registration of sponsor/developer as a commercial company according to Peruvian law and other necessary legal documents to support such claim.
- Before construction starts, capture and eventual water return has been authorized by the Water Authority. The license for water use is then granted automatically.
- Descriptive statement and full set of engineering drawings and maps of all project installations.
- Project implementation schedule and established deadlines.
- Project costs estimation and budget.
- Specification of the rights of way needed for the project facilities.
- National Institute for Natural Resources (INRENA) approval of the required studies for hydropower generation. The study needs to be at a pre-feasibility level and cover the area that is relevant for the project's water retention and intake, and the water return to the natural or artificial water source.
- Delimitation of the area requested for concession indicating *Universal Transversal Mercator* (UTM) coordinates.
- Approval of the Environmental Impact Study (EIS) by the General Directorate for Energy Environmental Matters (*Dirección General de Asuntos Ambientales Energéticos*, DGAAE) of the Ministry of Energy and Mines (MEM), or receipt of the request for approval.
- Security bond in favor of the MEM, in an amount equivalent to 1 percent of the estimated project costs, up to an amount of 50 UITs, which will be returned once the contract is signed.
- Report issued by a qualified rating agency ranking the credit-worthiness of the petitioner using a standardized ratings scale.
- Proof of capital investors' financing for the execution of works.
- The National Institute of Culture's (INC) Certificate of Nonexistence of Archaeological Remains (CIRA) can now be applied for once the concession has been granted.

The request and necessary documentation have to be presented at the MEM and should be approved within 60 working days of submission.

Water Rights

7. There are three sequential steps to obtain water rights:

- Authorization to conduct studies: it is not exclusive, but it is necessary to acquire a temporary concession: the National Institute for Natural Resources (INRENA) has to authorize the development of studies of water resource use for power generation, where there is no need to specify water volumes. It later has to approve such studies.
- During the process to grant a definitive concession, INRENA must have reviewed and given its opinion on the environmental study presented by the hydropower generation project, and has also approved the final studies for the project. Water volumes need to be specified.
- Once works execution has been granted, water use license before construction starts: INRENA has to grant a water use license for power generation before construction

starts. Water volumes need to be specified. Must obtain beforehand the Users Association's opinion, through consulting the affected Water Technical Administration (ATR).¹⁰⁰

8. This procedure is undergoing changes due to the recent creation of the National Water Authority, the entity that will take over many of INRENA's responsibilities. As a comparison, Box A.4.3 presents the Chilean water market case and how Chile has dealt with this situation.

Box A4.3: International Experience: Chile and the Chilean Water Market

The country's system is based on Legislative Decree 2603 of 1979 and the 1981 Water Code.

- Competitive access to the ownership title using a system of concessions, which are granted by the water authority free of cost through an auction to the highest bidder.
- Water conflicts are solved before non-specialized high law courts, which lack the necessary technical knowledge. As a result, rulings can be inconsistent with previous decisions in similar situations.
- A good hydrometric system is key.
- River basin organizations are the basis for the country's water management system.
- When it comes to traditional and native water rights, these can be hindered if there is an obligation to register them in order for them to be recognized as such.
- Need for an integrated and coordinated approach, which allows all agents to participate.

Appeals

9. Supreme Decree 078-2006-AG names the Regional Directorates for Agriculture as appellate bodies, where appeals against ATR's decisions take place, unless there is a Basin Authority with jurisdiction. Decisions by the Regional Directorates for Agriculture and INRENA can be appealed before the Ministry for Agriculture (although only as a second instance in INRENA's case). Appeals by users first take place before the ATR.

Current Procedures for Environmental and Social Impact Assessments

10. There are two types of environmental studies, according to the installed capacity: an Environmental Impact Study (Estudio de Impacto Ambiental, EIS) for plants above 20 megawatts (MW) and an Environmental Impact Declaration (Declaración de Impacto

¹⁰⁰ Supreme Decree 078-2006-AG creates, at a regional level, the Water District Technical Administration (*Asministraciones Técnicas de Riego*, ATR, later changed to *Administración Técnica de Riego*, ATR), dependent on the Regional Directorates for Agriculture. ATRs compile a preliminary, nonbinding report, which is used as a basis for INRENA's decision. Since there is not an established procedure, ATRs can require any document they might deem relevant. INRENA will then make its decision based on the report's findings.

Ambiental, DIA) for those plants with a capacity between 500 kilowatts (kW) and 20 MW.¹⁰¹ In addition, environmental studies presented by a hydroelectric plant must include a River Basin Management Plan (Enfoque de Manejo de Cuenca).

Environmental Impact Study

11. When the power plant has an installed capacity of more than 20 MW, an Environmental Impact Study, approved by the General Directorate for Energy Environmental Matters (DGAAE) at the Ministry of Energy and Mines (MEM), is needed. Guidelines are available at the ministry if required, as mentioned above.

12. The study has to identify and evaluate all possible direct and indirect environmental impacts, including biological, physical, cultural, and socioeconomic.

13. It has to include an Environmental Management Program (Plan de Manejo Ambiental, PMA), which will try to minimize, avoid, or compensate those negative effects, and any potential benefits, especially measures designed to protect local communities. It should be approved within 45 working days of submission.

14. The study has to be elaborated and signed by those professional entities authorized by the DGAAE.

Procedure

15. The study needs to be presented before the DGAAE and must be approved within 120 working days. If the DGAAE remains silent, it is understood that the study has not been approved.

16. Once the DGAAE has received the study, it will send a copy to the National Institute of Natural Resources (Instituto Nacional de Recursos Naturales, INRENA), part of the Ministry of Agriculture, and to the relevant Regional Directorate for Energy and Mines.

17. There is a maximum of 60 working days between the study's submission and the final evaluation by the DGAAE. During those 60 working days, INRENA has 20 to 30 working days (depending on whether there are any protected areas involved) to submit an opinion, which, although nonbinding, has to be positive for the DGAAE to approve the study.

18. Workshops and public hearings must be held for those interested. The law mandates that these hearings should be held in Spanish, with the use of interpreters when the audience or interested group uses another tongue, after which the authorities can make any kind of observations that need to be addressed by the concessionaire within 90 working days. Following these there is again a new deadline of 30 working days for

¹⁰¹ Both regulated in R.D. 008-97-EM (Maximum Emission Limits Permitted for Electricity Activities) and D.S. 029-94-EM (Rules for Environmental Protection in Electricity Activities).

INRENA to examine the study. This observations-discussions scheme can be repeated more than once, thus running the risk of eventually delaying the whole project.

19. Regarding the Environmental Impact Declaration (DIA) and the Environmental Management Plan (PMA), the DGAAE can ask for clarifications and can make other observations, which must then be addressed by the sponsor/developer within the time limit set up by the DGAAE (which will never be more than 90 working days).

20. Within 30 working days from the date construction is concluded, the concessionaire must submit to the Supervisory Commission for Investment in the Energy and Mining Sector (OSINERGMIN) a report detailing what actions it has taken to comply with those measures recommended in the environmental studies. If OSINERGMIN believes it necessary, it can recommend in this later stage a PMA as long as the project already had a previous environmental study.

River Basin Management Plan

21. A River Basin Management Plan is a sworn statement regarding the determination and maintenance of ecologic flows, recommending measures to guarantee the stability of environmental flows, water balances, and its existing ecosystem of draining water system toward the reservoir. These management plans must be formulated within the existing regional basin programs.

22. The management plan establishes guidelines and measures for the management and administration of hydrology and water resources. *Current Procedures for Right of Way*

23. Procedures imply several slight differences depending on whether it is a permanent or temporary right of way. The request needs to be sent to the DGE, which will in turn publish it in El Peruano and will eventually come up with an amount that needs to be paid as compensation.

Current Procedures for Certification of Nonexistence of Archaeological Remains

24. This certificate is required prior to construction. The certificate will be approved within 30 working days, and if the National Institute of Culture (INC) remains silent it must be considered as a rejection. However, these deadlines are sometimes not respected, thus creating some confusion as to whether the application has been approved or not. There have been cases where the approval was granted after 30 days.

The New Ministry for the Environment

25. Box A4.4 presents a brief overview of the role and responsibilities of the new Ministry for the Environment.

Box A4.4: The New Ministry for the Environment

The new Ministry for the Environment was established by Executive Decree 1013 in May 2008, and the regulations appeared in December 2008 (Supreme Decree 007-2008-MINAM).

The ministry establishes the general guidelines and the correct implementation of the government's policy on the environment. It coordinates, executes, supervises, and evaluates policy at the national and regional level. It guarantees the application of Peru's environmental legal framework, focusing on climate change, desertification, and water. Regarding water, it is not clear what the ministry's role will be or how it will be coordinated with other institutions.

After much debate, the National Water Authority will depend on the Ministry for the Environment, and the assessment of environmental studies will still be done by the Ministry for Energy and Mines.

Other relevant institutions depending directly on the Ministry for the Environment are the multisector commissions, an office to advise on environmental matters, and a tribunal (regulations still pending).

Annex 5: Electricity Auction Systems in other South American Countries

Brazil

1. The structure of the Brazilian electric sector was redesigned in the mid-1990s. This reform initiated a transition to a more competitive environment in the generation and supply of electricity, with a wider participation of private companies. Even before the transition to the competitive model was completed, Brazil faced a major crisis in electricity supply. Since the late 1990s, the level of storage in the hydroelectric reservoirs had progressively diminished. At the beginning of the dry period of 2001 (May), the southeast and northeast reservoirs operated at only one-third of their full capacities, an amount that is not sufficient to match the demand until the start of the next rainy season. To avoid the complete depletion of the reservoirs, in May 2001, the Government made rationing mandatory at a rate of 20 percent of the electricity consumption in the subsystems of the southeast/midwest and northeast.
2. Rationing lasted until May 2002. Consumption of electricity was drastically reduced, resulting in major economic consequences. Estimated total cost of the rationing is close to 3 percent of gross domestic product. Accepting that the “market model” was the cause of rationing, Luis Inácio Lula da Silva made it an electoral commitment to reshape the institutions of the Brazilian electric sector. Under the current president, the new model was debated and, in 2004, the new regulatory framework was implemented.
3. This second reform aimed at ensuring that a new supply crisis would not happen and at avoiding the rise of electricity prices. To do that, the Government resumed its role in the planning of the sector and drastically altered the wholesale market. Two institutions were created—the Energy Research Company (EPE), to assist the Energy Minister in sector planning, having played an important part at the expansion auctions; and the Electric Sector Monitoring Committee (CMSE), comprising representatives of the sector institutions (departments and regulatory agencies) and aiming at following up the expansion process, identifying where problems may arise.
4. Two environments were created for contracting in the wholesale market: the regulated contracting environment (ACR) and the free contracting environment (ACL). At the ACL, large consumers are free to choose their suppliers outside the centralized auctions system. The energy is negotiated through bilateral contracts with generators and traders. The contracts are of different duration and short-term contracts predominate.
5. At the ACR, the distribution companies buy energy in public auctions. They submit demand projections in a five-year horizon to the EPE. Based on those projections, the EPE sets the total market that will be offered in the auctions. In these auctions, generators compete, making bids (US\$ per megawatt-hour [MWh] and US\$ per megawatt [MW]) to take care of the distribution market. The winners then sign contracts with all the distribution companies that were part in the auction; in other words, the energy from each generator is divided among the distributors in the proportion that their market represents of the total amount negotiated. The energy sell price is defined by the

bids of generation companies (pay as bid) and the purchase price, paid by the distributors, is unique and corresponds to the sell price average.

6. The following are the main energy products to be auctioned in the ACR:

- “Old Energy,” corresponding to energy produced by existing, or ready-to-be-commissioned, generating plants, at the beginning of the second reform; which energy was included in the Initial Contracts of 1998. No new concession will be issued or environmental license required.
- “Botox” Energy, corresponding to a special case for energy produced by existing generating plants, which concessions were issued before the second reform, under the concept of “onerous concession.”
- “New Energy,” corresponding to the case of energy to be produced by greenfield projects, for which the water use rights and generation concession will be granted at the time of the auction, to the selected projects. Winning offers of lowest prices sign long-term contracts with distribution companies and large users.
- Energy from Specific Technologies, corresponding to energy from specific generating sources, such as small hydro plants, wind- and solar-powered plants, cogeneration and biomass plants, and other renewable sources. The Programme of Incentives for Alternative Electricity Sources (*Programa de Incentivo a Fontes Alternativas de Energía Eléctrica*, PROINFA) used this type of procedure.
- Special Auctions, for which the general conditions of the standard auctions are not suited, requiring particular conditions dictated case by case, due to the special characteristics of the projects, the large investments involved, and the large volume of energy production. An example of this type of auction was the one for the Rio Madeira development.

7. The auctions of “Old Energy” and “New Energy” are the most common; both are negotiated in the ACR in different ways. The old energy was oriented to respond to the existing market at the moment when the model was created. In the auctions of old energy, eight-year contracts were negotiated (with one exception as indicated below). On the other hand, the new energy is directed to the expansion of the distribution market. The new energy auctions are done with a prevision of three to five years ahead of the actual market and contracts are negotiated in the auctions with periods of 30 years and 15 years, for hydroelectric and thermal generation, respectively.

8. Since late 2004, there have been five “active” auctions of existing generation and two additional auctions; one had no offers and the last one was cancelled. They negotiated contracts beginning supply from 2005 to 2009. The offered contract period was eight years, with the exception of the third auction, which offered a contract of three years. Twenty-two producers and 39 distributors participated in the auctions. The state-owned generation companies dominated the supply, representing around 90 percent of the total energy negotiated in the auctions. Private generators adopted the strategy of orienting energy to the free market. Table A5.1 summarizes the results of the five active “Old Energy” auctions.

Table A5.1: Results of “Old Energy” Auctions, Brazil

Auction	Date	Beginning of Supply	Contract Period (years)	Quantity (GWh)	Price (Reals–US\$ per MWh)
1 st	Dec 2004	2005	8	634,939	57.51–21.14
		2006	8	475,608	67.33–24.75
		2007	8	82,190	75.46–27.74
2 nd	Apr 2005	2008	8	929,196	83.13–31.25
3 rd	Oct 2005	2006	3	2,683	62.95–28.10
4 th	Oct 2005	2009	8	81,769	94.91–42.37
5 th	Dec 2006	2007	8	14,306	104.74–50.34

9. In December 2005, the first “New Energy” auction was conducted, followed by six other auctions. The last auction (the seventh) indicated in this report was carried out in September 2008. In the “New Energy” auctions, hydro and thermal power plants receive different treatment. Hydropower plants compete on prices for the generated energy, and thermal power plants make bids for the capacity of production. The operational cost of thermal power plants, which win in the auctions, are paid and passed through to final consumers. As indicated, the contract periods are 30 years and 15 years for hydroelectric and thermal plants, respectively.

10. At the first stage of the auctions, the right of participation of the new hydroelectric projects is established, and the Government sets the maximum price of the energy produced by these plants, to be accepted in the auctions. Offers with the lowest bids win the right to participate in the second stage, where hydropower energy competes with other energy sources. Table A5.2 shows the results of the seven auctions of new energy carried, up to the date of this report. The “Type” column indicates whether the project is hydro (H), and in parenthesis the number of projects that won in the auctions, or thermal (T).

11. To appreciate the composition of the projects competing in the new energy auctions, additional details are given for the fourth and fifth auctions, carried out in July and October 2007. The fourth auction was directed to the energy supply starting in 2010 and the fifth for that starting in 2012. These two auctions were the conclusion of a long and complex planning task that included studies of the river basins’ potential for hydroelectric plants, forecasts regarding electricity demand from studies made by the distribution companies and the Government itself. The environmental licensing was the last and decisive step in this long process, which ensured the inclusion (or not) of the hydroelectric projects in the auctions.

Table A5.2: Results of “New Energy” Auctions, Brazil

Auction	Date	Beginning of Supply	Type	Quantity (GWh)	Price (Reals–US\$ per MWh)
1 st	Dec 2005	2008	H (6)	18,672.43	106.95–46.70
			T	73,769.25	132.26–57.76
		2009	H (4)	12,096.53	114.28–49.90
			T	112,408.56	129.26–56.45
		2010	H (16)	233,778.55	115.04–50.24
			T	113,349.55	121.81–53.19
2 nd	Jun 2006	2009	H (15)	270,331.10	126.77–56.85
			T	85,982.69	132.39–59.37
3 rd	Oct 2006	2011	H (6)	149,642.45	120.86–55.95
			T	70,350.3	137.44–63.63
4 th	Jul 2007	2010	H	0.00	—
			T	171,470.78	134.67 – 72.40
5 th	Oct 2007	2012	H (5)	188,039.28	129.14–71.74
			T	209,999.11	128.37–71.32
6 th	Sep 2008	2011	H	0.00	—
			T	141,489.70	128.42–70.56
7 th	Sep 2008	2013	H (1)	31,819.13	98.98–52.09
			T	394,941.89	145.23–76.44

12. From a set of studies and procedures a total of 106 power plants (hydro and thermal) were authorized by EPE and approved by the Brazilian Electricity Regulatory Agency (*Agencia Nacional de Energía Eléctrica, ANEEL*) to be eligible to participate in the auctions. The total installed generating capacity offered was equivalent to 16,022 MW. The information indicated that of the total of 106 plants registered, 61 used renewable energy sources, and 45 used nonrenewable sources for power generation. Of the 61 renewable energy plants listed, 26 projects were hydroelectric, 7 plants used wind power, and 28 projects used biomass. In the case of projects using nonrenewable sources of energy, 32 plants were approved for fuel oil and diesel, 4 for natural gas, 3 were bi-fuel (natural gas and diesel), 4 were coal fired, and 2 were referred to coke thermal plants. Table A5.3 summarizes the projects that were approved to enter the auctions.

Table A5.3: Projects Composition of the Fourth and Fifth Auctions of “New Energy,” Brazil

Generation Source	PLANTS	Capacity (in MW)	% of Capacity
Renewable	61	4.722	29,5
Hydraulic	26	3.076	19,2
Eolic	7	765	4,8
Biomass	28	881	5,5
Non Renewable	45	11.300	70,5
Thermal NG	4	2.960	18,5
Thermal bi-fuel (NG and diesel)	3	1.977	12,3
Thermal Fuel Oil and Diesel	32	3.421	21,4
Thermal Mineral Coal	4	2.242	14,0
Thermal Coke	2	700	4,4
Total	106	16.022	100,0

Source: GESEL- IE-UFRJ, based on EPE data

Colombia

13. The Colombian auction system is quite different from its “similar” in Latin America. A fundamental characteristic of the Colombian electricity system is that it has an active short-term energy market, based on energy price offers from generators; the last (more expensive) marginal offer determines the energy spot price used in the transactions in the wholesale electricity market.¹⁰² The system also included a capacity payment to “attract” new investments, considering that solely marginal energy payment to generators was insufficient to cover new entry long-term costs.

14. This capacity payment was calculated administratively by the regulator, and considered low by generators if compared to the practice in other regional countries of setting this payment at such a level to cover standard peak-load generating units costs. It was the Government’s view that the capacity payment was not the right answer to the adequate reliability level for the power system in Colombia, of having sufficient thermal resources and hydro reservoirs to provide firm energy during a dry period. In 2006, after detailed studies, the electricity regulator introduced a firm energy market to provide the investment and operating incentives for suppliers to build and operate the efficient quantity and quality of energy resources. The objective was for this market to reduce supplier risk and improve reliability, resulting in reliable electricity at minimum cost to consumers.

¹⁰² In Brazil, Chile, and Peru the power dispatch is based on unit (audited) costs and not on price offered by generators; therefore, in these countries there is no short-term energy market.

15. The product of the reliability energy market is a financial call option, backed by a physical resource (power plant) certified as capable of producing firm energy during a dry period. The physical requirement guarantees that sufficient resources will be available to produce the required firm energy. The financial call option hedges load (distribution companies and large users) from high energy prices during periods of scarcity. The supplier's generating units and available fuel supply provide a physical hedge to limit the risk of selling the call option; relative to an energy-only market, the supplier's risk is reduced, since the firm energy market substitutes highly variable energy rents with a constant firm energy payment.

16. The supplier's obligation (in the aggregate) is to follow the load (the power demand); that is, a set of suppliers has to cover the demand since this varies with time (on a daily basis): in each hour the total obligation is equal to firm energy load. A supplier's obligation on any day is equal to its share of firm energy. The obligation is distributed over the day based on the hourly dispatch. This definition—tying a unit's obligation to its hourly dispatch during scarcity—reduces market power and improves the performance of the spot energy market. A base load unit's obligation is spread throughout the day; a hydro unit with high opportunity cost's obligation is concentrated in the peak hours of the day.

17. The key features of the reliability of the energy market are:

- The Planning Period—the time between the primary auction and the beginning of the supplier's commitment—initially is three years, but this will increase by six months in each successive auction, until it reaches four years. Projects with even longer lead times can sell firm energy as a price-taker up to seven years ahead.
- The Commitment Period for existing resources is one year. The commitment period for new resources is between 1 and 20 years. New resources select their preferred commitment length during the auction qualification. The firm energy price is adjusted for inflation during the commitment period
- A parameter in the auction is the Cost of New Entry (CONE). Initially, this parameter is estimated by the regulator; subsequently, it is adjusted based on competitive auction results.
- The Demand Curve specifies how the purchased quantity of firm energy depends upon price. At the CONE, load purchases its firm energy target (100 percent of estimated firm energy demand). At higher prices, load purchases slightly less than the target quantity; at lower prices load purchases slightly more than the target quantity. The firm energy price has a ceiling of two times the CONE and a floor of one-half times the CONE.
- A Descending Clock Auction design is used, intended to promote price discovery. The price starts at a high price (two times the CONE) and suppliers bid the quantity they are willing to supply at that price. If there is excess supply, the

price is reduced and again suppliers respond with their willingness to supply. This process continues until supply and demand balance, which determines the quantity won by each supplier and the clearing price paid to all suppliers during the commitment period.

- The clock auction includes a simple activity rule: as the price declines suppliers can maintain or reduce quantities; quantities cannot increase. Thus, a supplier's offers must be consistent with an upward-sloping supply curve. Existing resources can opt out of the market, but this choice does not impact the firm energy price paid to existing resources.

18. Performance incentives largely come from the energy spot price. Those that supply more than their share during scarcity periods are rewarded and those that supply less are penalized. In each case, the marginal incentive comes from the energy spot price. In addition, a supplier's certification of firm energy depends on its estimated ability to supply firm energy in a dry period. This estimate depends at least in part on historical performance, and this provides an additional incentive.

19. The auction design recognizes the possibility that there may be either inadequate supply or insufficient competition. The fail-safe mechanism specifies what happens in these unlikely events. Shortly after the primary auction, a reconfiguration auction is held for each commitment year that has not yet occurred, but for which firm energy has already been procured in an earlier primary auction. These reconfiguration auctions allow suppliers and load to balance their positions in light of improved information. For example, a project may proceed faster or slower than anticipated, and load growth may be faster or slower than expected. In addition, a monthly auction is held during the commitment year to further balance positions. All these auctions are sealed-bid clearing price auctions.

20. The firm energy price is set administratively in each of the first four years (2007–10). During this period, the product includes the hedge for load. Beginning in 2011, the firm energy price is set in a competitive auction. To reduce risk in early auctions when the planning period is shorter, the firm energy payment for existing resources has a tighter floor and ceiling. The floor decreases and the ceiling increases for existing resources following each of the first three competitive auctions.

21. The first firm energy auctions (Firm Energy Obligations, *Obligaciones de Energía Firme, OEF*) were held in May and June 2008 and allocated OEFs for periods of up to 20 years beginning in December 2012. As a result, some 9,000 gigawatt-hours (GWh) per year of OEFs were allocated to new resources, along with 62,860 GWh per year allocated to existing generating plants at an auction-determined "option" price of US\$13.998/MWh. Existing generating plants will receive the option fee for a single year beginning December 2012, while new resources are guaranteed the fee for up to 20 years. Subsequent auctions will be held whenever the *Comisión de Regulación de Energía y Gas* (CREG) estimates that the demand for energy in future years cannot be covered

during scarcity periods by the energy production of existing generation resources and any planned new resources that will enter into operation.

22. The first primary auction, held in May 2008, conducted four-and-a-half years in advance of the commitment period (the “planning period”), was a “descending clock auction” (DCA) for new resources and effectively a sealed-bid auction for existing power plants, since bids for existing plants had to be submitted before the beginning of the auction, and could not be modified afterward. In this auction, new resources were able to lock in a firm energy price for up to 20 years, beginning in December 2012, while existing resources receive the price set by the auction for a single year only. The reserve price used in the auction was two times the CONE, as established by the CREG, and a price floor of one-half the CONE was also used, so that the CREG was committed to purchase all energy offered at that price.

23. There were 17 participants in the primary auction. Ten new power plants were initially offered (three coming from the same company—Gecelca), with a combined yearly capacity of 9,185 GWh, while the remaining capacity offered came from existing plants (62,860 GWh per year). Of the new plants offered, only three were successful in the auction: (a) coal-fired Geselca 3 of 150 MW, (b) fuel-oil-fired Termocol of 201.6 MW, and (c) hydroelectric Amoya of 78 MW. Of the new plants, two came from new entrants into the Colombian market—Poliobras and Cosenit—and, as indicated, only Poliobras was successful in the auction. The other two companies that sold OEFs for new power plants were already large players in the Colombian electricity market: Gecelca with 16 percent of existing capacity, and Isagen with 12 percent. Table A5.4 summarizes the breakdown of new capacity offered by existing players and new entrants in the DCA.

Table A5.4: Composition of New Capacity Offered in the First Primary OEF Auction

Generating companies	Power Plant	Technology	OEF Offered [GWh]	Market share	Share of new capacity
ISAGEN	Amoyá	Hydro	214	12%	2%
GECELCA	Gecelca 2, 3 & 7	Coal	2,979	16%	34%
POLIOBRAS	Termocol	Fuel Oil	1,678	0%	18%
COSENIT	Termodial1	Petroleum	208	0%	2%
MERILÉCTRICA	Merilectrica-cc	CC-Gas	602	2%	7%
PROELÉCTRICA	Termoandinaí	Gas	766	1%	8%
TERMOCANDELARIA	Termocandelaria-cc	CC-Gas	1,449	2%	16%
TERMOTASAJERO	Tasajero2	Coal	1,290	2%	14%

24. The auction “clock” started at a reserve price of US\$26.09/MWh (2xCONE) reducing to US\$22/MWh in the first round, and then decreased in US\$2/MWh decrements in each subsequent round. The auction ended in the sixth round at a price of US\$13.998/MWh. Of the 65,869 GWh of firm energy “purchased” in the auction for the first year (December 2012–November 2013), new power plants accounted for 3,009 GWh per year (4.6 percent) while existing generating units accounted for 62,860 GWh per year (95.4 percent). The only new hydroelectric plant that participated, and won OEF, in the DCA was Amoya, which offered 214 GWh per year.

25. The secondary auction, held in June 2008, was for new generation projects with longer construction periods (geothermal power plants, GPPS), and allocated OEFs for periods of up to 20 years beginning in December 2014. The GPPS auction rules establish a two-stage process. In the first stage, bidders submit their quantity offers over five years. If supply exceeds demand in any of the five years, then a sealed-bid auction is held in which each bidder submits a single price bid for its entire offered quantity. Bidders are not informed in which year (or years) there is either excess supply or excess demand.

26. Six new hydropower projects participated in the auction. The reserve price in this auction was the “market clearing” price established in the “descending clock” auction. Since the incremental supply offered by bidders was less than incremental demand in every year, the reserve price was paid to the six bidders for power plant projects commencing from December 2014 to December 2018; therefore, a sealed-bid auction

was not necessary for any supply year. Table A5.5 shows the results of the GPPS auction.

Table A5.5: Results of the First Geothermal Power Plants (GPPS) Auction

Company	Project	Capacity (MW)	Energy per Year (GWh)					Total	Available
			2014/15	2015/16	2016/17	2017/18	2018/19		
Epsa	Cucuana	60	49.5	0.5	0.0	0.0	0.0	50.0	50.0
Promotora	Miel II	135.2	182.6	1.8	0.0	0.0	0.0	184.4	184.4
EMGESA	El Quimbo	396	400.0	450.0	500.0	300.0	0.0	1,650.0	1,750.0
EPM	Porco IV	400	0.0	320.6	320.6	320.6	0.0	961.7	1,923.0
ISAGEN	Sogomatoso	800	400.0	400.0	750.1	750.1	50.0	2,350.3	3,791.0
Hydroelectrica	Pescadero Ituango	1,200	0.0	0.0	0.0	0.0	1,085.0	1,850.0	8,563.0
Incremental Supply			1,032.0	1,174.0	1,571.0	1,371.0	1,135.0	6,286.4	16,261.4
Incremental Demand			1,779.0	1,910.0	1,965.0	2,013.0	2,170.0	9,836.0	

27. Sector specialists indicate that a critical assumption of the reliability energy market is that it is competitive for new entry. Thus, as part of the market implementation, it is important for regulators to take steps to reduce barriers to entry. A second critical assumption is that suppliers have faith that the market, once implemented, will endure for the lifetime of new plants. Hence, it is important for the Government to make a commitment to the approach and to honor the commitment. Entry barriers and political risk can undermine even the best market designs. The regulators and Government must recognize and address these challenges, otherwise the market could provide high-cost, not least-cost, investment.

Chile

28. Even before the problems created in the Chilean electricity sector by the natural gas supply restrictions by Argentina, there was a noticeable reduction in the level of investments in new generation, to respond to the demand growth. The main cause of this problem, as reported by the industry, was the relatively low regulated price of electricity generation, caused mainly by the unrealistic generation expansion plan, used to establish the development marginal expansion cost of generation, which serves as the basis for the calculation of the regulated tariffs.

29. To avoid these problems and eliminate the administrative calculation of the regulated tariffs, the Chilean Government approved Law No 20018, in May 2005, establishing an auction system by which distribution companies should contract their supply needs in competitive bids and sign long-term contracts with generating companies at prices resulting from the bid process. The prices resulting from the bids will be passed to consumers.

30. The Chilean auction system has characteristics very similar to the one in Peru; therefore, we will describe it very briefly here as a complement to the discussion in this annex.

31. The following are the main characteristics of the Chilean auction system:

- First price sealed bid auction.
- 100 percent of demand must be contracted all the time.
- Contracts for 15-year period.
- Contracts for base and variable energy supply.
- Demand is divided into blocks to allow partial supply offers.
- Utilities may group to allocate larger demand blocks.
- Indexation formulas are established by generators.
- The regulator establishes a reserve price (price cap) in each auction.
- Allocation mechanism: First round Price cap = Node price + 20 percent; second round Price cap = Node price + 15 percent, (30 days later).

32. There have been two auctions up to the date of this report. The first auction had one round and the second auction two rounds. No new plants were offered in these auctions, indicating some design problems. Table A5.6 shows the results of these two auctions, complemented by price details shown in Table A5.7.

Table A5.6: Main Results of Auctions, Chile

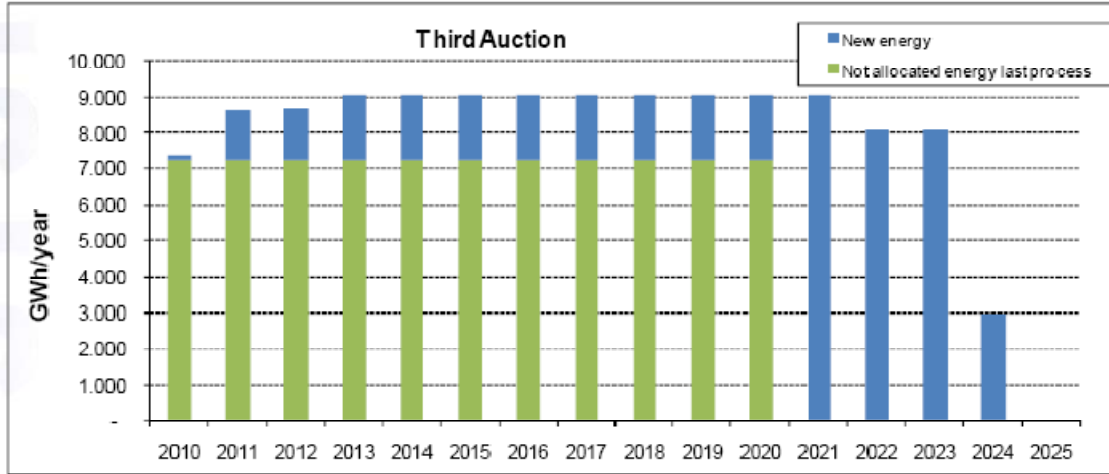
Auction	Date	Energy Auctioned	Energy Allocated	Price Cap US\$/MWh	Ave. Price US\$/MWh
1 st	Oct 2006	14,160	12,766	61.7	52.8
2 nd First Round	Oct 2007	14,732	5,700	62.7	61.2
2 nd Second Round	Mar 2008	9,032	1,800	71.06	65.5

Table A5.7: Complementary Price Results of Auctions, Chile

Auction date	GenCo	Bid price (US\$/MWh)	Indexed bid price sept 08 (US\$/MWh)	Supply begins	Average price sept 08 (US\$/MWh)
Auction 1 2006	Endesa	50.8	71.6	2010	94.2
	AES Gener	56.4	130.1		
	Colbun	53.9	111.6		
	Guacolda	55.1	99.8		
Auction 2 2007	Endesa	61.0	69.3	2011	65.9
	Colbun	58.2	60.3		
Auction 2.2	AES Gener	65.8	67.5		

33. A third auction was planned to take place in December 2008, but it was postponed to March 2009. Figure A5.1 shows the energy requirements for the third auction, comprising the energy not allocated in the previous auctions and the additional (new) expected demand, with a total yearly peak of 9,032 GWh during 2013–21.

Figure A5.1: Energy Requirements of Third Auction, Chile



BIBLIOGRAPHY

- Agencia de la Promoción de la Inversión Privada (ProInversion). 2006 *Estudios de Prefactibilidad Económica-Financiera de la Provisión del Gas a las Regiones del Interior del país (ProInversión 2004-2006)*. Lima.
- Angina P., Briscoe, J., Pena H. 1998. "Managing Water as an Economic Resource: Reflections on the Chilean Experience" *Environment Department Papers No 62*. The World Bank. Washington D.C. April.
- Bolens, R., Getches, D. and Guevara, A. 2006. *Agua y Derecho: Políticas Hídricas, Derechos Consuetudinarios e Identidades Locales*. Instituto de Estudios Peruanos (IEP).
- Bustamante, J. 2008. Dificultades para Centrales Hidroeléctricas: Características y Comentarios de los Proyectos Hidroeléctricos con concesiones en el Perú. Draft Report. Washington D.C.
- Corporación de Desarrollo del Nor-Yauyos (CODENY). 1999. *Diagnóstico de la Zona Reservada Alto Cañete y Cochas-Pachacayo*. Working Document. Lima. May. Available at <http://www.geocities.com/proyauyos/Archivos/ZReservadaFinal.doc>
- Comité de Operación Económica del Sistema - Sistema Interconectado Nacional (COES-SINAC). 2007. "Estudio Técnico Económico de Determinación de Precios de Potencia y Energía en Barras para la Fijación Tarifaria de Mayo de 2008." Report submitted to the Organismo Supervisor de la Inversión en Energía y Minería (OSINERGMIN). Lima, November. Available at <http://www2.osinerg.gob.pe/gart.htm>.
- Comisión Técnica Multisectorial. 2004. *Estrategia Nacional para la Gestión de los Recursos Hídricos Continentales del Perú*. Lima.
- Commission on Legal Empowerment of the Poor. 2008. *Making the Law Work for Everyone Volume II*. New York.
- Donoso, G., Melo, O., Jordán, C. undated. *Mercado de Derechos de Aprovechamiento de Aguas de la Primera Sección del Río Maipo, Región Metropolitana: Comportamiento de los Diferentes Agentes Económicos y Variabilidad en Precios*. Pontificia Universidad Católica de Chile. Santiago.
- Donoso G. 2006. "Water Markets: Case Study of Chile's 1981 Water Code." *Ciencia e Investigación Agraria*, 33(2): 157-171 Pontificia Universidad Católica de Chile. Santiago. Available at: <http://www.rcia.puc.cl/Espanol/pdf/33-2/9-Water1.pdf>
- El Peruano. 2008a. *Decreto Legislativo No. 1002 Decreto Legislativo de Promoción de la Inversión para la Generación de Electricidad con el Uso de Energías Renovables*. Lima May 2.
- El Peruano. 2008b. *Decreto Legislativo No. 1013, Decreto Legislativo que Aprueba la Ley de Creación, Organización y Funciones del Ministerio del Ambiente*. Lima. May 14.
- El Peruano. 2008c. *Decreto Legislativo No. 1003, Decreto Legislativo que Agiliza Tramites para la Ejecución de Obras Publicas*. Lima. May 2.

- El Peruano. 2008d. *Decreto Legislativo No.1078 Decreto Legislativo que Modifica la Ley 27446, Ley del Sistema Nacional de Evaluación de Impacto Ambiental*. Lima June 27.
- Gayoso, R. 2007a. “*Estudio de Revisión y Actualización Hidrológica de Caudales Naturalizados para Generación de Energía Hidroeléctrica por EDEGEL en el Rimac*.” Report to Empresa de Generación Eléctrica de Lima (EDEGEL) S.A.A., July.
- Gianella, J. 2007. *Naturalización de la Información Hidrológica del Río Vilcanota*. Report to Empresa de Generación Eléctrica Machu Picchu S.A. (EGEMSA). Lima July.
- Guigale, M., /Newman, J., and Fretes-Cibilis, V. 2007. *An Opportunity for a Different Peru: Prosperous, Equitable, and Governable*. World Bank Publication. Washington D.C.
- Hearne, R., and Donoso, G. 2005. “Water Institutional Reforms in Chile”. *Water Policy* 7(1): 53-70.
- Infoclim@. 2007. “*Estudio de Evaluación de las Normales Climatológicas Utilizadas en las Cuencas de Operaciones de la Generadoras Integrantes del COES SINAC*”, Report submitted to Comité de Operación Económica del Sistema (COES), Lima, October.
- IPCC (Intergovernmental Panel on Climate Change). 2007. “Fourth Assessment Report.” Cambridge University Press. Available at: <http://www1.ipcc.ch/ipccreports/assessments-reports.htm>
- Lahmeyer Agua y Energía S.A. 2007. “*Pucara Hydropower Plant – Basic Design Report*.” Report to Empresa de Generación Eléctrica Cuzco S.A. (EGECUZCO) and Project International Development (PID). Lima. September.
- Meir, P. 2008. *Economic Financial Analysis of Hydropower in Peru*. Draft Report. Washington D.C.
- Millones, J.E. 2008. *Análisis de los Estudios de Impacto Ambiental Desarrollados para Centrales Hidroeléctricas*. Draft Report. Lima.
- Ministerio de Economía y Finanzas. 2007. Boletín Diario. Lima. September 11.
- Ministerio de Economía y Finanzas. 2007. Boletín Diario. Lima. October 22.
- Ministerio de Energía y Minas. 2006. *Plan Referencial de Electricidad 2006–2015*. Dirección General de Electricidad. Lima. Peru.
- _____. 2007a. “Estructura de Precios de los Combustibles”. *Informe Mensual Estadístico*. Lima.
- _____. 2007b. Informes semanales de Precios Referenciales y Precios Reales de los Combustibles Derivados del Petróleo”. Lima
- Organismo Superior de la Inversión en Energía y Minería (OSINERGMIN). 2007a. *Propuesta de Plan Energético al 2015*. Lima.

- _____. 2007b. *Operación del Sector Eléctrico, Reporte Estadístico, Septiembre 2008 y Diciembre 2007*. Lima.
- _____. 2007c. *Fijación de los Precios en Barra para el periodo Mayo 2007-Abril 2008*. Lima.
- _____. 2008a. “*Fijación de los Precios en Barra aplicables al periodo comprendido entre el mayo 2008 y abril 2009*”, Resolución N° 341-2008-OS/CD, Lima, April 2008; available at <http://www2.osinerg.gob.pe/gart>
- Organismo Superior de la Inversión en Energía y Minería (OSINERGMIN) and Universidad ESAM. 2008. *Análisis de Barreras de Entrada para la Inversión en Centrales Hidroeléctricas*. Departamento de Estudios OSInergmin. Lima. Junio. Available at: http://www.osinerg.gob.pe/newweb/uploads/Estudios_Economicos/Informe%20Final%20Barreras%20CH%20.pdf
- Pena, H., and Solanes, M. 2003. *Effective Water Governance in the Americas: A Key Issue*. Global Water Partnership. Presented at the Third Water Forum in Kyoto, Japan. March. Available at <http://www.cepal.org/samtac/noticias/documentosdetrabajo/2/23422/DrSam00303.pdf>
- Rogers, P. 2002. *Water Governance in Latin America and the Caribbean*. Inter-American Development Bank. February. Available at: <http://www.iadb.org/sds/doc/ENV-PRogers-WaterGovernanceinLAC.pdf>
- Servicio Nacional de Meteorología e Hidrología (SENAMHI). 200x. *Balance Hidrico Superficial del Peru a Nivel Multianual*. Lima. Available at: <http://www.senamhi.gob.pe/?p=0702>
- United States Army Corps of Engineers. 1971. “*Monthly Streamflow Simulation: Computer Program HEC4*.” Hydrologic Engineering Center. Davis, California.
- URS. 2008. “Study of Equipment Prices in the Energy Sector.” Report to the World Bank. Washington, D.C., April.
- World Bank. 2004b. “Hydrology Project Phase II.” Project Appraisal Document (PAD No. 28140-IN) on a proposed loan to the Government of India. Washington, D.C., July 19.
- _____. 2008. “Peru Natural Gas Study.” Anexo 4: Valoración del Gas. Draft Report. Washington, D.C.
- _____. 2008. “State and Trends of the Carbon Market.” Washington, D.C.
- _____. Forthcoming (a). “Assessing the Impacts of Climate Change on Mountain Hydrology – Development of a Methodology through a Case Study in Peru.” Washington, D.C.
- _____. Forthcoming (b). “Peru – Institutional and Financial Framework for Development of Small Hydropower.” Washington, D.C.
- _____. Undated. *Cost Effectiveness of the Environmental Licensing System in Brazil*, Draft Concept Note. Washington D.C.

The Energy Sector Management Assistance Program (ESMAP) is a global knowledge and technical assistance trust fund program administered by the World Bank and assists low- and middle-income countries to increase know-how and institutional capability to achieve environmentally sustainable energy solutions for poverty reduction and economic growth.





Energy Unit
Sustainable Development Department
Latin America and the Caribbean Region
The World Bank

