Namibia IPP and Investment Market Framework Technical Assistance

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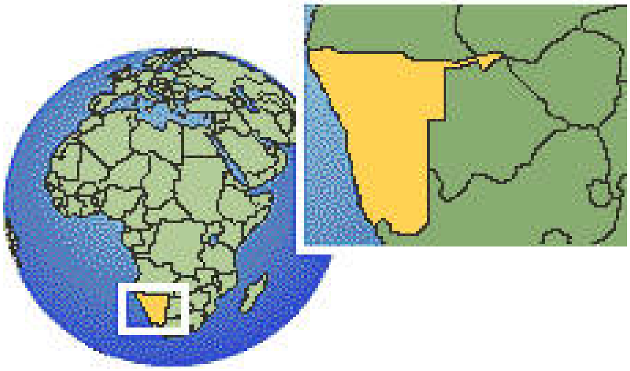
Volume I: Final Report



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NAMIBIA IPP AND INVESTMENT MARKET FRAMEWORK TECHNICAL ASSISTANCE

VOLUME I: EXECUTIVE SUMMARY AND MAIN REPORT

TABLE OF CONTENTS

NAMIBIA IPP AND INVESTMENT MARKET FRAMEWORK TECHNICAL ASSISTANCE

VOLUME II: ANNEXES

TABLE OF CONTENTS

DISCLAIMER BY CORE INTERNATIONAL, INC.

CORE International has completed and presented its Final Report which includes this Main Report as Volume I and a set of 12 annexes as Volume II. This Report is in complete response to the Terms of Reference included in CORE International's contract with the Electricity Control Board of Namibia and those included in the Grant Agreement between the Electricity Control Board of Namibia and the U.S. Trade and Development Agency (USTDA). The Report also conforms to the Mandatory Clauses required as part of any contract issued to any firm under USTDA grants.

The process of power sector reform in any setting is more than a technical matter. Since major changes in policy and the institutional structure are required to design the optimum level of reform along with its implementation, the process will, of necessity, become politicized. This political process is critical to creating the type of support for power sector reform that must underpin a successful program. Namibia is no different in this regard.

The findings and recommendations included in our Report derive their basis from the current energy policy in Namibia and the mandate of the Electricity Control Board as the electricity regulator. In addition, discussions with various officials in Namibia and the information gathered during various consultative working sessions and workshops has been used, as appropriate, in framing our recommendations. This report represents our best effort to assist the Electricity Control Board in its deliberative process and decision-making for the design and implementation of an approach to encourage the entry of Independent Power Producers (IPPs) in Namibia's power sector.

As independent professional consultants, we have focused strictly on the technical aspects of various issues and deliberately stayed away from any political dialogues as that is not our role. However, some of the IPP *policy* recommendations contained in our Report will cause political dialogue among various energy sector stakeholders in Namibia. Moreover, we understand that discussion of the findings and recommendations in our Report, specifically some of the international IPP case studies and examples may stimulate both policy and political discussions as indeed they must, in order to be helpful in forging a policy consensus on the IPP issue. It is our understanding and experience that such discussions will naturally bring forward the views of some parties in Namibia who may not agree with some of our recommendations. We understand this just as we understand that it is up to the Namibian parties to make the appropriate decisions with respect to the type and speed of reform of the Electricity Supply Industry (ESI) that is in the best interest of Namibia. It is not the role of external consultants to be involved in the actual decision making process.

Finally, the report prepared by CORE International, Inc. should be treated as a dynamic document and both the findings and the recommendations contained in the Report will change as energy sector policy and regulatory requirements in the country change. The Report offers the Namibian electricity sector planners a basis to debate and analyze different options for the reform of the ESI to the extent Namibia feels that it is in the interest of the country to encourage private participation in Namibia's power generation through the commissioning of IPPs.

THE CORE TEAM

CORE International's Team that conducted this Technical Assistance included the following experts:

1. Mr. Vinod Shrivastava, Senior Energy Expert, CORE International, Incorporated Corporate Manager

2. Dr. Donald I. Hertzmark, Senior Economist, CORE International, Incorporated Team Leader

3. Dr. Paul Sotkiewicz, Regulatory Expert, Public Utility Research Center, University of Florida

4. Mr. Thomas Heller, Legal/Regulatory Expert, Stanford University

5. Ms. Lois Varrick, Development Impact and Outreach Expert, CORE International, Incorporated

6. Mr. Uli von Seydlitz, Energy Supply Industry Expert, EMCON Consulting, Namibia

7. Ms. Mercedes McVicker, Project Associate, CORE International, Incorporated

ACKNOWLEDGEMENTS

This Final Report is an outcome of extensive collaboration with a large number of counterpart Namibian officials from various agencies who extensively contributed to the definition of issues and analyses in a number of work sessions conducted by CORE International, Inc. throughout the seven-month duration of the Technical Assistance. Our work and the recommendations contained in the Final Report benefited significantly from the contribution of many key individuals in Namibia. We express our sincere appreciation to all of them.

At the outset, we are indebted to the personal commitment and leadership of Mr. Siseho Simasiku, Chief Executive Officer, Electricity Control Board (ECB), Namibia. This work was carried out under the direct overall guidance of Mr. Simasiku. In addition, Mr. Simasiku generously offered ECB's resources to the CORE Team in the conduct of our work. We are very appreciative of the personal commitment of Mr. Simasiku to the importance of work. The day-to-day aspects of CORE's work were under the direct supervision of Mr. Gerrit Clarke, Manager, Regulatory Support Services, ECB. Mr. Clarke provided the CORE Team all the support needed during our various field missions. He also organized a number of consultative sessions with NamPower and other energy sector stakeholders which provided significant inputs to the various issues surrounding the development of an Independent Power Producer (IPP) industry in Namibia. Mr. Clarke actively participated in all of the working sessions, meetings, and workshops and contributed greatly to the overall report. We are very appreciative, indeed, to Mr. Clarke's active involvement throughout the conduct of this TA. We would also like to express our appreciation to Ms. Jacky Scholz, Legal Advisor, Mr. Rojas Manyame, Manager, Technical Regulations, and Ms. Helene Vosloo, Manager Economic Regulation, all at the ECB, for their contributions to our work. We would also like to acknowledge the support of various administrative personnel at the ECB and the Regional Electricity Regulators Association (RERA), especially, during the various workshops and working sessions.

The list of individuals that the CORE Team interacted with throughout this TA is simply too long to be reproduced here. It is provided as Annex 3 to the Final Report. However, we would like to specifically acknowledge the following individuals for their support, guidance, and comments to our Team:

From the Ministry of Mines and Energy, we would like to express our appreciation to Mr. Joseph S. Iita, Permanent Secretary, Selma-Penna Utonih, Director of Energy, David Namulo, Cecilio Mateu, Mulife Siyambango, Maxwell Muyambo, Analie Banna, and Nordien Hipangelwa.

Many senior managers from NamPower participated in working sessions and discussions and generously offered their time and advice to the CORE Team. We are especially grateful for the contributions made by Mr. Paulinus Shilamba, Managing Director; Mr. Reiner Jagau, Chief Technical Advisor; Mr. John Langford, General Manager for Strategy and New Generation; Constantia U. Pandeni, Renewable Energy; and Ms. Margaret van der Merwe, Kudu Project Leader.

Other Namibian officials with whom the CORE Team interacted on various occasions include Mr. Robert Mwanchilenga, Development Engineer, Namcor; Mr. Ferdinand Diener, Strategic Executive, Electricity, City of Windhoek; Mr. Tarah Shaanika, CEO and Ms. Charity Mwiya, Operations Manager, both at the Namibia Chamber of Commerce and Industry; Mr. Ger Kegge, Country Manager, Energy Africa (Tullow Oil); Mr. Gottlieb N. Amanyanga, Chief Executive Officer, NORED Electricity; Mr. Gerhard Coeln, Chief Executive Officer, Erongo Regional Electricity Distribution Company (Pty) Ltd.; and Mr. Veston Malango, General Manager, Chamber of Mines. We express our sincere appreciation to all of these and other Namibian officials for their support and guidance.

Officials from the American Embassy in Namibia have been quite supportive of this effort from the very beginning. Her Excellency Joyce Barr, the American Ambassador gave us her personal support and encouragement for which we are deeply indebted to her. In addition, other officials of the American Embassy who continue to support private participation in Namibia's power sector include Mr. Eric D. Benjaminson, Deputy Chief of Mission and Ms. Adrienne M. Galanek, Economic and Commercial Officer. Also, we would like to express our appreciation to Mr. Douglas Ball, Assistant Director, USAID Mission, Namibia for sharing his thoughts on the power sector issues in Namibia.

Finally, we would like to express our sincere appreciation to the U.S. Trade and Development Agency for providing the grant to the Electricity Control Board, Namibia that made this study possible. In particular, we express our appreciation to Sub-Saharan Team at USTDA including Mr. Ned Cabot, Regional Director; Ms. Ursula Iszler, Country Manager, and Mr. Douglas Shuster, USTDA Representative in Africa.

GLOSSARY OF TERMS

The following terms have been frequently used throughout the Main Report and all of the annexes to the Report. They are defined here to facilitate the readers of the Report.

ADB	Asian Development Bank
AfDB	African Development Bank
AFUR	African Forum for Utility Regulators
BOI	Board of Investment
CORE	CORE International, Incorporated
DRC	Democratic Republic of Congo
ECB	Electricity Control Board
ESD	Energy Service Delivery
EPC	Engineering, Procurement, and Construction
ERR	Economic Rate of Return
ESI	Electricity Supply Industry
Eskom	Electricity Supply Company, South Africa
EU	European Union
FRR	Financial Rate of Return
FSA	Fuel Supply Agreement
GEF	Global Environment Facility
GW	Giga Watts
HVDC	High Voltage Direct Current
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITCs	Independent Transmission Companies
JPX	Johannesburg Power Exchange
JV	Joint Venture
Kudu	A Power Generation Project being Developed by NamPower
kW	Kilo Watts
LOI	Letter of Intent
MME	Ministry of Mines and Energy
MSMB	Multiple Sellers Multiple Buyers
MW	Mega Watts
NARUC	National Association of Regulatory Utility Commissions
NERSA	National Energy Regulator of South Africa
NP	NamPower
O&M	Operations and Maintenance
PPA	Power Purchase Agreement
PTO	Permission to Occupy
RED	Regional Electricity Distributor
RERA	Regional Electricity Regulators Association
RERED	Renewable Energy for Rural Economic Development
RSA	Republic of South Africa
SAPP	Southern African Power Pool
SOE	State Owned Enterprise
The Act	Electricity Act of 2000
The Bill	The Electricity Bill, 2006
The FI Act	Foreign Investment Act, 1990
TNA	Training Needs Assessment
USAID	U.S. Agency for International Development
USTDA	U.S. Trade and Development Agency
World Bank	International Bank for Reconstruction and Development

EXECUTIVE SUMMARY

Economic Development Context in Namibia

Namibia is currently undergoing a healthy surge in its economy, driven largely by the minerals industry and its exports into a booming international market. Despite this growth in exports of minerals and fish, the country faces a worsening employment situation. This led the former President of Namibia, Dr. Sam Nujoma, to articulate a plan for a dramatic transformation of the Namibian economy. This plan, called Vision 2030, seeks to boost the economic and social performance of the country's economy dramatically over the next two decades, so that Namibia achieves "industrialized" status by 2030.

Key elements of attaining the overall sustainable development enunciated by Vision 2030 include the following:

- Transformation of the country to a knowledge-based society – increasing emphasis on information technology and education;
- Improvements in public health and reduction in prevalence of HIV/AIDS
- Increased output of basic foodstuffs in a sustainable manner
- Reduction in racial and gender inequalities across the spectrum of social, economic and educational opportunities.

The concrete manifestation of the success of Vision 2030 will come in the rates of change in various key social and economic indicators of Namibia. Improved education and economic participation will increase the rate of economic growth. Expansion of the mining industry, a sub-indicator, will certainly lead to additional growth in electricity demand. Increased use of computers and telecommunications, both powered by electricity, will also increase the demand for both new generation and expanded transmission and distribution networks throughout the country. Improved public health will come about in part due to greater use of modern medical technology in rural areas, again raising the demand for electricity. The issues of direct relevance to this study are the ways that changes in the social and economic indicators might affect the rates of change in demand for electricity and the country's strategy to meet that demand.

Increasingly, the realization of a developed and modern society includes reliable and sustainable electricity supplies. As with many countries today, Namibia has decided that using government debt to provide for investment in additional electricity generation is neither an appropriate nor an affordable choice for the government. If new electricity supplies are to be acquired using non-governmental funds there are essentially two (complementary) options: (i) purchase electricity from neighboring countries with surplus electricity generation capacity; and (ii) attract private investors to develop power plant projects using their own funds.

The central question facing the country's planners is -- **How will Namibia meet its future demand for electricity?** This technical assistance focuses on choices that need to be made and decisions that need to be implemented in order to ensure that Namibia has adequate supply of electricity to fuel the planned economic growth and meet the goals of Vision 2030.

The Power Sector in Namibia

The Namibian power system is based on hydro and thermal generation sufficient to meet minimal demand conditions. At present, the system relies heavily on imports from Eskom, South Africa to meet base load electricity demand and indigenous hydropower to meet most of the peak demand. The country has an internal transmission system that is adequate to move power around the domestic market. Namibia is connected with all of its neighbors, with the most active interconnection being the 220 kV and 400 kV ties to the Eskom system. Namibia also exports on small to medium scale to Angola and Botswana. Additional transmission links with Zambia, now under construction, will enable power to move between the two countries more effectively according to pricing and other market conditions.

Generation capacity, aside from standby generation in the mining industry and a few isolated generating sets, consists of three power plants. The current peak demand for electricity in the country is 400 MW, which exceeds the current NamPower generation capacity by about 5%. Captive generation in the mining industry is probably capable of preventing an overall shortage of electricity, at least in the near term. With an average demand for electricity of 300 MW and demand of more than 320 MW for at least 15 hours per day during the work week, the Namibian electricity system relies heavily on imports from South Africa to meet normal demand.

Over the next few years, as the surplus from South Africa, which is traditionally meeting more than half the country's electricity demand, continues to fall, Namibia will need to look at new sources of supply. The Base Case forecast for electricity demand indicates that even under rather modest assumptions the demand for electricity will approximately double by 2020.

The key institutions in Namibia's power sector include the Ministry of Mines and Energy (MME); NamPower, the national utility; and The Electricity Control Board (ECB), the national regulator. NamPower acts as an integrated generation and transmission company with its entity NamPower Energy Trading acting as the electricity system's Single Buyer and only trader thus far. This entity also imports from and exports to neighboring countries (South Africa and Zambia). NamPower Generation's output is also purchased by this unit.

NamPower Transmission then sells the power on to a small number of transmission customers. These are a mix of large users (mostly mines and water pumping schemes), the Regional Electricity Distributors (REDs), and an array of smaller consumers who, for legacy reasons, are connected directly to transmission substations. There are also some cross border supplies where NamPower Transmission supplies power at the distribution or sub-transmission level to Angola, Botswana and South Africa.

ECB, the regulator is relatively new, and is in transition as the sector undergoes reforms. ECB is a member of the Regional Electricity Regulators Association (RERA) and the African Forum for Utility Regulators (AFUR). NamPower is also a member of the Southern African Power Pool (SAPP) and is engaged in power trading under SAPP.

Context for the Technical Assistance

The following key Acts and documents have provided the context within which this technical assistance was carried out:

- Vision 2030
- ECB Strategic Plan
- The White Paper on Energy Policy
- The Electricity Act
- The ESI Restructuring Study
- Foreign Investment Act of 1990

- Competition Act of 2003
- Electricity Bill of 2006 (pending)

- State-owned Enterprises Bill of 2006 (promulgated since compilation of this report)

While it was not our role to review these documents and provide any comments, all of our work was guided by the provisions contained in these documents related to the electricity sector.

Objectives of the USTDA Technical Assistance to the Electricity Control Board in Namibia

In addition to the guiding documents mentioned above, the actual scope of work of the CORE Team was focused on the Grant Agreement between the ECB and U.S. Trade and Development Agency (USTDA) and was defined by the Terms of Reference in the Grant Agreement and CORE International's contract with the ECB.

Given the rapid pace of power sector reform in Namibia, the ECB requested assistance from the U.S. Trade and Development Agency (USTDA) to prepare ECB in order to address the need for the entry of Independent Power Producers (IPPs) in the country's power sector. In response to ECB's request, USTDA provided a grant to ECB to finance the cost of technical assistance. CORE International, Inc., a U.S.-based international management consulting firm, was selected by the ECB through a competitive selection process to provide the technical assistance. The technical assistance was conducted over a seven-month period by the CORE Team that consisted of CORE International, Inc., Washington, D.C., U.S.A. and EMCON Consulting Group, Windhoek, Namibia. The technical assistance focused on (i) the development of a formalized energy market model with a focus on how to facilitate investments by Independent Power Producers, (ii) addressing the current capacity deficit and security of supply situation by allowing flexibility for a future move towards wholesale or retail competition in the market, (iii) making recommendations on the options for private sector participation in the Namibian energy sector, and (iv) the development of framework strategy documents to implement the recommended private sector promotion model.

The Final Report completed by CORE International is in two volumes: Volume I: Main report (including this Executive Summary) and Volume II: Annexes (a total of 12 annexes on a variety of subjects including details of the market model, the regulatory model, the models of various sized IPPs, and a series of model documents). The Final Report is in complete compliance to the requirements of the USTDA Grant to the ECB and CORE's contract with the ECB.

The Choices for Namibia

A successful implementation of the Vision 2030 would result in a quadrupling of electricity peak demand by 2030, requiring not only the Caprivi Link and Kudu, but also a number of other sources of electricity supply. As mentioned earlier, even under rather modest assumptions, the demand for electricity will approximately double by 2020.

Basically, Namibia has two choices to prepare for this anticipated demand for power – (i) buy electricity from neighboring countries with surplus capacity and subject itself to supply and price vulnerability; or (ii) mobilize a regime to attract private investors in power generation in Namibia.

The same factors that drive the domestic demand for electricity – population growth, mining activities, tourism, and rising affluence – also exist in South Africa and pose similar challenges to Eskom, the main electricity supplier in South Africa. Eskom has faced unprecedented difficulties in meeting demand growth in South Africa and has unveiled an ambitious investment program exceeding US $16 billion to increase capacity significantly over the next ten years. The implications for Namibia are as follows:

- Eskom will face a sizeable challenge meeting South Africa's domestic electricity demand over the next 10-15 years;
- Transmission capacity within South Africa needs to be significantly augmented in the short term;
- New generation stations are likely to cost more than the older technologies that they replace;
- Bringing old plants out of mothballs will likely lower the overall level of system reliability; and
- South Africa faces unprecedented challenges from shortages of skilled labor and project management to meet its stated construction goals and deadlines.

The implications of the current trends in national electricity demand in Namibia and regional electricity supply mean that:

- Namibia has outgrown the continued availability of its traditional source of supply from South Africa;
- The Caprivi Link will provide a cushion for only two more years, based on current generation sources, before additional sources of supply are needed; and
- Major new supplies of electricity from Zimbabwe transported over the Caprivi Link are highly uncertain.

Thus, long-term continued dependence for electricity supply on Namibia's largest traditional supplier – Eskom is not an option that is in the best interest of the country.

The second choice for Namibia is increased domestic generation at privately-owned power plants. A number of possible investments have been identified, including the 800 MW gas-fired project at Kudu and an additional 400 MW coal-fired power plant at Walvis Bay. Pending successful border discussions with Angola on water rights issues, additional hydroelectric capacity can be constructed near the Ruacana plant in the North. However, with the exception of NamPower's own Kudu Power Project, currently there are no firm plans to construct privately-financed power plants in the country.

If the Kudu Power Project achieves success in its Power Purchase Agreement (PPA) negotiations with the various parties, the immediate supply crisis for the country will have been averted. However, given the need to sell most of Kudu's capacity to South Africa, the amount of new capacity available to address Namibia's growing demand for power may be limited by the middle of the next decade, especially as the Vision 2030 program picks up momentum.

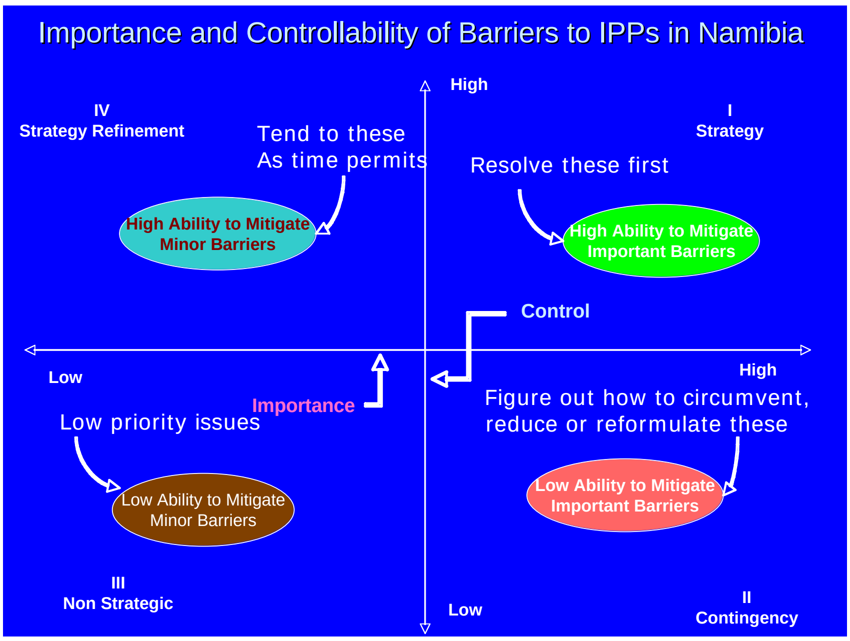
Additional base load power supply, probably coal, will need to be considered if the country is to avoid the costly acquisition of combustion turbines as a stop-gap measure, as has happened in South Africa. In addition to the security of supply that is created with new investments in domestic generation capacity, such investments will also bolster the country's negotiating position for acquiring additional supplies from neighboring countries, contractually or on the spot market. They will also strengthen Namibia as a regional trading partner in power trading in the Region.

The downside of attracting Independent Power Producers (IPPs) to provide for domestic power demand is that the country does not now provide an environment that is conducive to significant private investment in the power sector. There is no single factor that is dispositive as regards private electricity generation investment. But, together the negatives present a collection of barriers that must be resolved before private investors and Namibian consumers can have full confidence in the efficient, fair and sustainable supply of electricity from IPPs.

Why are there no IPPs in Namibia today?
At the start of this assignment, the CORE Team worked with ECB and NamPower to assess the overall environment for IPPs in Namibia. The CORE Team examined factors – demand, political stability, strong economy, well-run utility – that promote IPPs. We also analyzed factors – low retail power prices, absence of a gas supply agreement, weak REDs – that inhibit IPP investments. In order to assess how these barriers might affect the success of IPPs in Namibia and to formulate mitigating strategies, the CORE Team, in close working sessions with ECB and NamPower, constructed a barrier and risk matrix that represents the pricing, financial, regulatory and policy barriers that impede the development of a healthy independent private power industry in Namibia. These barriers were organized with respect to the level of their importance to the success of a potential IPP program in the country and the degree to which the Namibian power sector planners can control or mitigate them. Exhibit 1 depicts the Barrier Matrix that formed the basis for the entire analysis throughout this technical assistance.

The barriers that need to be addressed as the highest priority are those in the Strategy Quadrant, I. These barriers must be mitigated before IPPs can go forward. For such barriers, one entity or another in Namibia has the ability to affect the outcome of an IPP project by their actions – these risks and barriers are generally highly controllable. Examples of such barriers are pricing, structural and contractual; namely low domestic prices for electricity, concern about domestic pricing impacts of higher-priced electricity, lack of a sale-purchase agreement with South Africa for IPP output, and the lack of a fully-functioning Single Buyer market in the country.

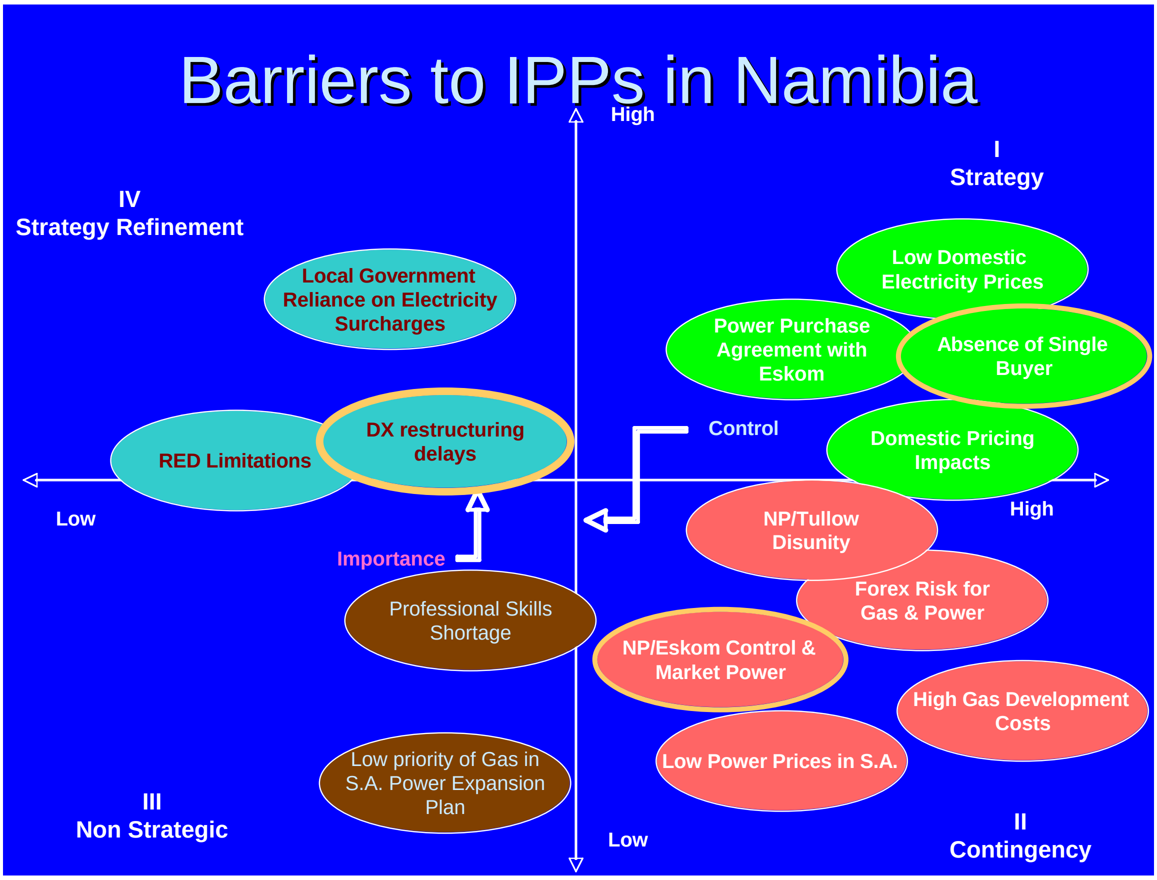
EXHIBIT 1: IPP BARRIERS MATRIX



Almost as important as the strategy barriers are the contingency barriers (Contingency Quadrant II). These barriers, though difficult to control, are important to the project and represent significant risks to the success of an IPP project. In order to succeed in Namibia, an IPP program must find ways to mitigate, transform, circumvent or otherwise reduce the importance and impact of uncontrolled but significant risks. Examples of important, but uncontrolled IPP risk factors include gas development costs at Kudu, power prices in South Africa, foreign exchange risks for Kudu or a coal project, and relations between NamPower and Tullow, the Kudu development partners. Some of these barriers will resolve themselves to some degree. For example, current cost trends in South Africa will limit the negotiating leverage of Eskom with respect to price, as increasing difficulties in its power development program lead to rising electricity prices. Other barriers, for example, high gas development costs at Kudu, are not within the power of Namibian government officials to control and will have to be mitigated in other ways. Similar risk factors will be present in any other large power project in Namibia.

Approaches to Mitigate Risks and Barriers
The recommendations and follow-up activities suggested under this Technical Assistance (TA) are to a large degree an outgrowth of the barriers identified at the initial stages of the TA in discussions with the Namibian energy sector stakeholders. Exhibit 2 provides a summary of the joint assessments of the barriers and risks to IPPs conducted by the ECB and the CORE Team.

EXHIBIT 2: APPROACH TO MITIGATING BARRIERS AND RISKS TO IPPs IN NAMIBIA



In order to mitigate the risks associated with IPPs in Namibia and to reduce the adverse impacts of the barriers identified by both the ECB and the CORE Team, the project focused on a multi-layered approach to reducing risks and preparing the country's electric power system for a successful introduction of IPPs. This approach, laid out below, focuses on (i) market models and pricing barriers; (ii) regulatory barriers; and (iii) policy issues. Concrete recommendations for mitigating IPP risks are included with each assessment.

Create a Market Model for Namibia that Addresses the Concerns of Investors and Mitigates Risk for NamPower and the Government

The key market and pricing related risks identified in the initial stages of the project included:

- Incomplete implementation of the Single Buyer Model for Namibia;
- Concern about domestic pricing impacts of large IPPs; and
- Low power prices in South Africa as a drag on prices that Namibian IPPs can recover.

In order to create mitigating measures for these barriers the CORE Team worked with the ECB to assess the state of current market restructuring in Namibia. This assessment found that the current efforts toward market restructuring, though incomplete, were moving in an appropriate direction.

In looking at regional trends in power sector restructuring, we were struck by the incompleteness of the process throughout the Region. Since Namibia is a small market, and remains a price taker, either as a buyer or a seller of electricity in the region, it became clear that the country could not get ahead of regional trends in market structure and openness. As a result, the CORE Team has recommended that a modified Single Buyer Market Model be maintained as long as Namibia's neighbors fail to complete their own restructuring processes. In particular, the absence of a transparent market with a complete array of products (e.g., the Johannesburg Power Exchange) would put a fully restructured Namibian power industry at a disadvantage commercially if the country's electricity buyers and sellers were highly fragmented.[1] Exhibit 3 provides a comparative illustration of the current Single Buyer Market Model and the Modified Single Buyer Market Model.

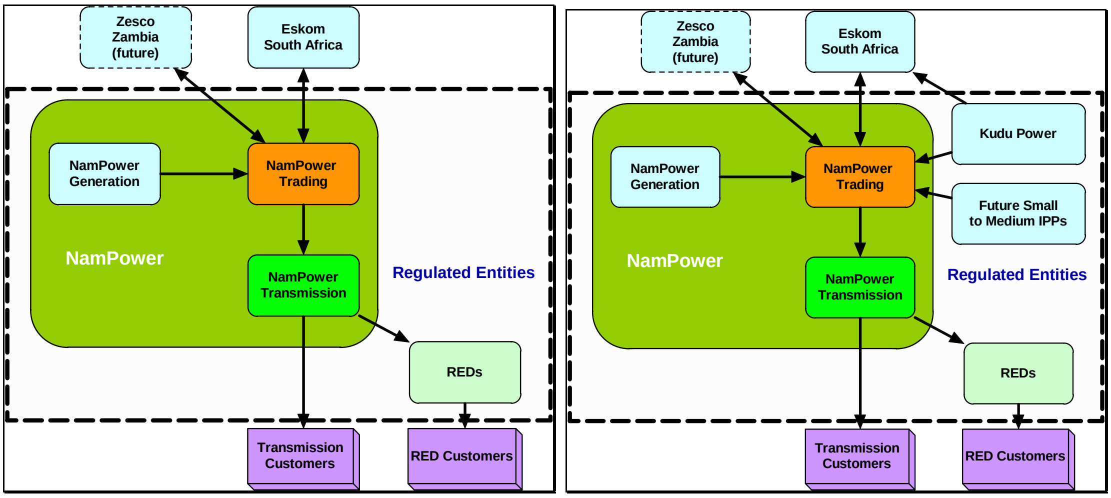
The CORE Team has assessed the available market models using a single buyer approach and recommends that a Modified Single Buyer Model be used for Namibia. In this formulation NamPower would remain the trader and market operator. The key considerations in looking at an IPP model are risk mitigation and incentives for investors. Much of the adverse experience worldwide with IPPs has come from mismanagement of risk, in particular, government guarantees of the take or pay conditions in the power purchase agreement. Avoiding that pitfall, that is, avoiding government guarantees of off-take payments, is one of the primary goals of this assignment.

The Modified Single Buyer Model approach could accomplish a portion of this necessary reduction in the government's financial exposure. The CORE Team recommends that other parties be permitted to purchase electricity from IPPs, on a limited basis, and to reduce the financial exposure of both NamPower and the Government of Namibia to liability for take or pay requirements. For the smaller IPPs, the customer should be the REDs, not NamPower Trading. This frees NamPower from a responsibility to oversee a

[1]. A market for electricity, such as the delayed JPX, gives each participant, large or small, access to the same market information. Where individual agents face a large seller, without full access to information on costs and quantities, the asymmetry in the relationship generally runs to the disfavor of the smaller, fragmented side.

number of very small (<5 MW) power plants that will not contribute to meeting system capacity requirements. At the other end of the scale, for very large IPPs (>300 MW), where the financial barriers are the most significant, the CORE Team recommends that some of the larger customers in the country be encouraged to purchase capacity from the large IPPs directly, with the right to sell excess off-take to export markets through NamPower Trading. This is essentially a financial risk mitigation strategy for NamPower and, therefore, for the Government of Namibia, since NamPower Trading and NamPower as the system operator will still retain control of both the trading apparatus and the physical flows of electricity, but will not need to bear the same level of financial risk as if they were liable for the entire off-take of a very large IPP.

EXHIBIT 3: CURRENT MARKET MODEL AND THE RECOMMENDED MODIFIED MARKET MODEL IN NAMIBIA



Namibia Current Market Model | **Proposed IPP Risk Mitigation Market Model**

Provide a Regulatory Environment that Aligns Prices, Risks and Incentives

During the technical assistance, the CORE Team and ECB also focused on regulatory solutions to risk mitigation. This regulatory approach stands as a counterpoint to a full legal and financial de-integration of the NamPower system. As was already noted, the current state of restructuring of electricity markets not only in Namibia but also throughout the Region has left a panoply of semi-finished electricity transformations – not quite the state-owned and vertically integrated enterprises of old, but not the multi-seller multi-buyer models once envisioned as the norm for the Region either. The Team has recommended that a modified single-buyer market is an appropriate “resting” place for the next few years until a more thorough restructuring is completed in South Africa and in Namibia’s other large electricity trading partners.

In order to provide an attractive environment for IPPs, while protecting domestic electricity customers, an additional layer of responsibility will fall on the ECB. In addition to its oversight of NamPower contracts and prices, the ECB will need to assist in the creation of an environment that assures potential investors of a level playing field in Namibia. At the same time, the ECB will need to make sure that conditions are not too attractive for IPPs and that price pass-throughs from the IPPs are appropriate and prudent. In other words, regulation must not be too harsh, pricing pass-throughs should not be too lenient – the ECB should seek the combination of oversight, incentives and enforcement that is just right for encouraging investors while protecting consumers.

To thread this needle effectively, the ECB will need to strengthen its staff and operational capabilities. The kinds of oversight activities and regulatory priorities that will be needed to create the optimum regulatory environment will involve the following major activities:

1. Reduce perceptions by investors that the current playing field for new capacity favors NamPower;
2. Maintain the synchronization of prices paid for electricity by NamPower Trading and prices paid by consumers; and
3. Reduce transactional costs and uncertainties, especially for smaller IPP investors.

The ECB can bring about this "just right" environment for IPPs with the following types of activities:

1. Resolve bias issues by (i) greater ECB involvement in and oversight of NamPower capacity planning; establishing ECB/NamPower due diligence for contract evaluation and awards; and (iii) increase confidence in the fairness of NamPower dispatch results by publishing ex ante the results of dispatch.

2. Avoid misalignment of prices paid to IPPs and prices paid by customers by (i) putting large IPP price adjustment clauses on the same schedule as the ECB retail market adjustments; (ii) limiting pass-though of costs to the specifically permitted cost elements; and (iii) putting small IPPs on a price-taking payment schedule that is keyed to the NamPower or RED wholesale electricity price.

3. Smaller investors can benefit from reduced transactional costs through an ECB program to provide standard contract formats for IPPs below 100 MW, especially those using renewable sources of energy. Some of the key agreements, such as fuel supply agreements, power purchase agreements, and operational contracts, are described in the text of the Main Report, with details included in several annexes to the Report.

4. Institute a comprehensive program aimed at strengthening the capacity of ECB and enhancing the skill sets of ECB Managers and staff in a number of key areas in order to assist the ECB in creating an enabling environment for the entry of various types of IPPs into the Namibian power market. ECB and the CORE Team have jointly identified a number of key areas where ECB capacity building needs to commence as soon as possible. Some of the specific areas include – (i) governance improvement, (ii) approaches for negotiating large IPPs, (iii) tender preparation and model documents for granting licenses to smaller IPPs, (iv) stakeholder coordination best practices, (v) consumer education and customer participation approaches including public hearings, (vi) regulatory standards for customer service, (vii) best practices in arbitration and dispute settlement, (viii) cost of service and tariff review approaches, (ix) risk quantification and mitigation strategies – case studies, and related areas.

The technical assistance was performed by the CORE Team in close collaboration with the ECB, with the Chief Executive Officer of ECB involved at every stage of deliberations and all work sessions and workshops. As a result, the CORE Team was able to focus on the issues consistent with the power sector reform and restructuring priorities of Namibia. Two added dividends of the close working relationship were that both the problem definitions and the recommended solutions and strategies had the direct input of the ECB and the challenges that ECB faces were explicitly considered in designing the

CORE Team's recommendations for the next steps. NamPower also participated in all key working sessions and workshops and made extensive contributions to both defining the process of IPP investments and the barrier analysis.

Finally, it is clear from this exercise that Namibia, as a country, and the key energy sector stakeholders, as the national champions of power sector reform, need to prepare themselves to implement the changes required in order to encourage the entry of IPPs into the Namibian power sector not only to enhance the country's security of energy supply but to also do their part in fostering the achievement of Vision 2030. The reliability and security of the electricity supply will not only lead to accelerated economic development of the country but the entry of IPPs, especially large IPPs, will make Namibia a stronger power trading partner in the Region.

I. BACKGROUND AND CONTEXT

A. THE NAMIBIAN ECONOMY

Namibia is a large, sparsely-populated country at the Western edge of Southern Africa. The country's population of about 1.8 million translates to a labor force of just over 800,000 and is engaged primarily in agriculture (47%), services (33%) and industry (20%). In recent years the economy has been buoyed by growing demand for minerals and GDP has grown at a real rate of almost 4% in the past year, down from 6% in 2004. Economic growth in 2006 should be higher, reflecting the boom in natural resource exports to the rapidly-growing economies of East Asia.

Namibia is a leader (fourth in the world) in the production and export of non-fuel minerals and occupies one of the leading roles in the following categories: diamonds, uranium, lead-zinc, tin, silver, and tungsten. Mining employs just over 3% of the labor force, while accounting for roughly 20% of GDP.

The country relies heavily on its agricultural sector for employment, especially in the subsistence agriculture segment. However, Namibia still imports more than 50% of its grain (cereal) needs. Livestock and fishing are both growing sectors of the economy. Still, employment outside subsistence agriculture has failed to keep pace with the growth of the labor force for a number of years, with youth unemployment an especially troublesome aspect of the economy.

In light of the disparity between a healthy overall economy and a worsening employment situation, the previous President of Namibia, Dr. Sam Nujoma, articulated a plan for a dramatic transformation of the Namibian economy. This plan, called Vision 2030, seeks to boost the economic and social performance of the country's economy dramatically over the next two decades, so that Namibia achieves "industrialized" status by 2030.

The vision for the economy and society of Namibia is one of a joint public and private endeavor, spanning a wide range of economic, financial, educational and social sectors. Key elements of attaining the overall sustainable development enunciated by the Vision include the following:

- Transformation of the country to a knowledge-based society – increasing stress on information technology and education;
- Improvements in public health and reduction in prevalence of HIV/AIDS;
- Increased output of basic foodstuffs in a sustainable manner; and
- Reduction in racial and gender inequalities across the spectrum of social, economic and educational opportunities.

The concrete manifestation of the success of Vision 2030 will come in the rates of change in various key social and economic indicators. Improved education and economic participation will increase the rate of economic growth. Expansion of the mining industry, a sub-indicator, will certainly lead to additional growth in electricity demand. Increased use of computers and telecommunications, both powered by electricity, will also increase the demand for electricity generation and transmission and distribution systems throughout the country. Improved public health will come about in part due to greater use of modern medical technology in rural areas, again raising the demand for electricity. The issues of direct relevance to this study are the ways that changes in the social and economic indicators might affect the rates of change in demand for electricity. That question is explored in the next section in the general discussion of the future of the country's electricity system.

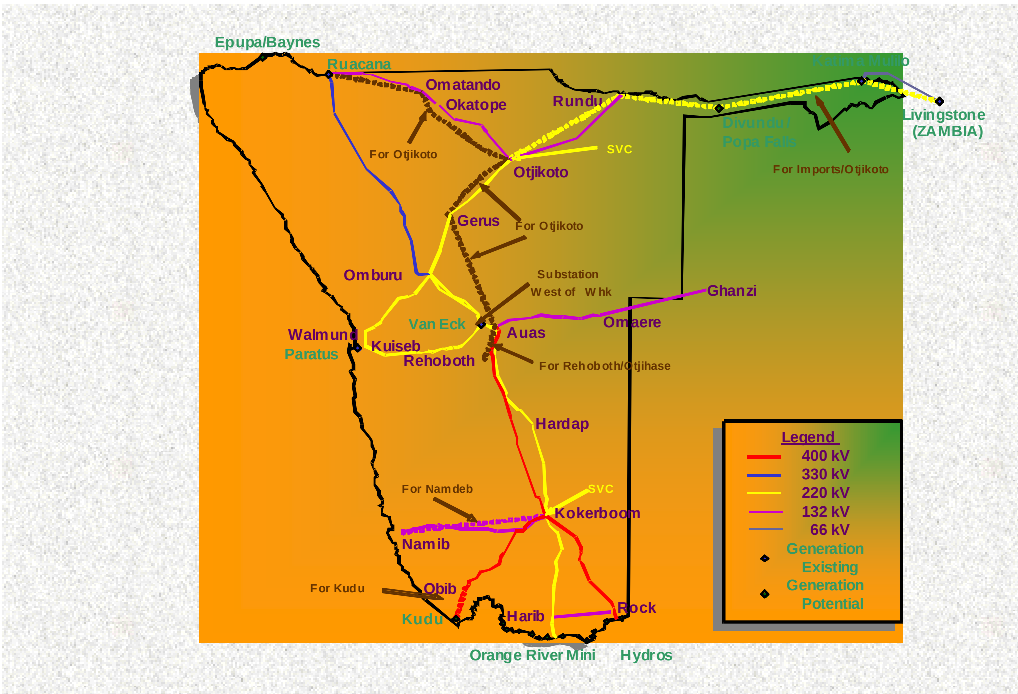
B. POWER SECTOR BACKGROUND

1. ELECTRICITY SUPPLY, DEMAND AND PRICING ISSUES

This section provides a discussion of the current power system in Namibia. It includes a discussion of the physical system, the current supply of electricity, and the demand and pricing issues. Annex 1 provides further details.

Namibia's Electric Power System – Physical Description
The Namibian power system is based on hydro and thermal generation sufficient to meet minimal demand conditions. At present, the system relies heavily on imports from Eskom to meet base load electricity demand and indigenous hydro to meet most of the peak demand. Exhibit I-1 shows the current transmission line and power plant locations.

EXHIBIT I-1: NAMIBIA'S HIGH VOLTAGE POWER GRID, 2005[2]



The country has an internal transmission system that is adequate to move power around the domestic market. Namibia is connected with all of its neighbors, with the only true interconnection being the 220 and 400 kV ties to the Eskom system. Additional transmission links with Zambia, now under construction, will enable to country to move power more effectively according to pricing and other market conditions. Generation capacity, aside from standby generation in the mining industry and a few isolated generating sets, consists of three power plants. These are shown in Exhibit I-2.

[2]. *Source: NamPower*

EXHIBIT I-2: NAMIBIA'S POWER GENERATION PLANTS – 2005
(EXCLUDING GENERATION AT THE MINES AND ISOLATED GENSETS)

Plant	Location	Capacity	Comments
1. Ruacana hydro power station (run of river)	Plant is situated in the north of Namibia where the Kunene River becomes the Border between Namibia and Angola	240/249 MW	This station has completed civil works for a fourth hydro machine as well as black start-up diesel generators A small weir upstream of the plant permits eight hours per day of water regulation for the Ruacana facility
2. Van Eck coal-fired power station	Windhoek	120 MW	No black start capability Operates as a standby facility using high-grade coal
3. Paratus diesel power station	Walvis Bay	24 MW	Has black start capability Main use for station is to meet peak demand or for standby capability for local market

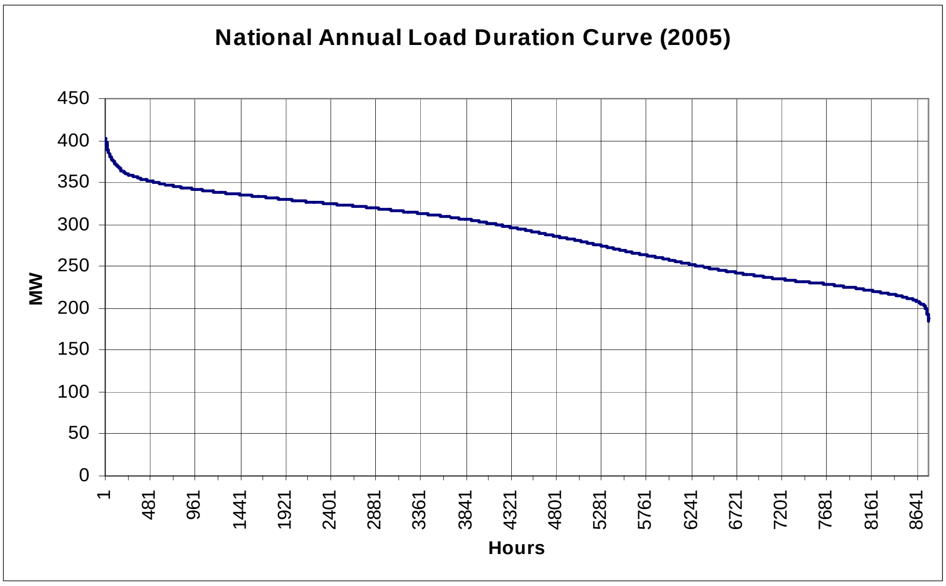
Namibia's Electric Power System – Current and Forecast Demand
The current peak demand for electricity in the country is 400 MW, which exceeds the current NamPower generation capacity by about 5%. Captive generation in the mining industry is probably capable of preventing an overall shortage of electricity, at least for a short period of time. With an average demand for electricity of 300 MW and demand of more than 320 MW for at least 15 hours per day during the work week, the Namibian electricity system relies heavily on imports from South Africa to meet normal demand. Exhibit I-3 shows the load curve for Namibia which indicates the annual distribution of demand throughout the day.

Since the compilation of the above graph the start of Kudu production has been delayed to at least 2010/11 i.e. by no less than three years. The MOU between NamPower and Eskom regarding the surplus of Kudu makes provision for Eskom to buy the balance of Kudu less local demand.

While the domestic segment contributes almost half of the peak demand, mining and industrial/commercial use accounts for almost 70% of total electricity use (see Annex 4 for details). The minimal ability to meet average demand will be overcome by even modest demand growth in the next 5-10 years. The high probability increases in electricity demand (i.e., low rates of annual increase) call for at least an additional 100 MW by 2015. Industrial and mining step loads could contribute an additional 70 -100 MW[3] and maintaining the current rate of economic growth would lead to demand increases of an additional 100 MW for commercial and domestic users by 2015-2020. In other words, a relatively high probability exists that demand will increase by 100-300 MW during the next 10-15 years, far exceeding the ability of the domestic generating system to meet even base load demand. (For additional details on demand forecasts, please see Annex 4).

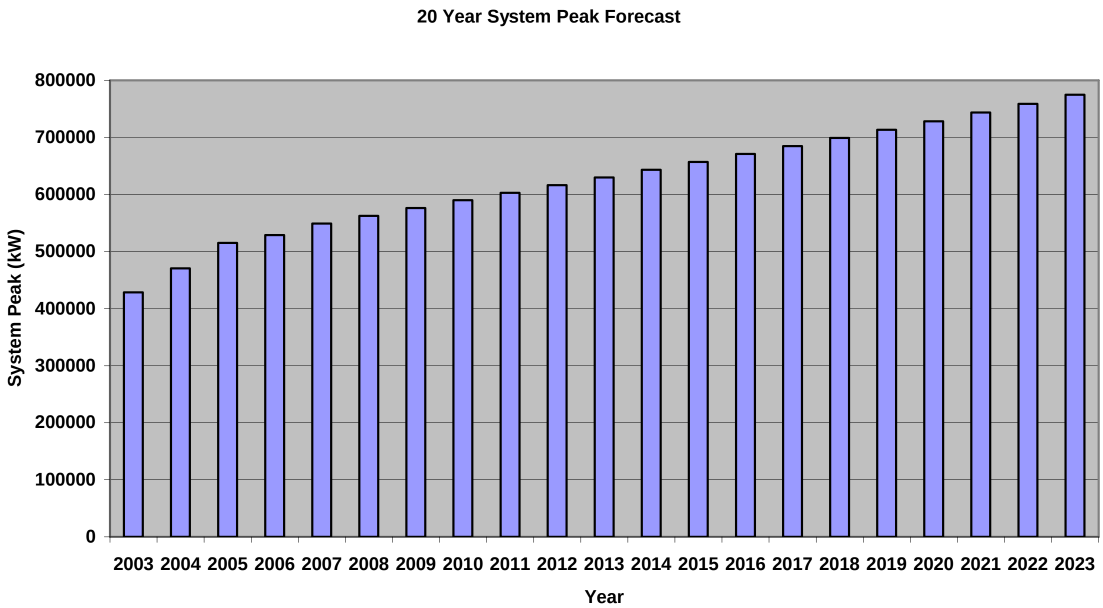
[3]. *Additional mining demand represents additional base load. However, since mining generally represents firm capacity demand, these new loads will add to peak demand requirements.*

EXHIBIT I-3: AVERAGE ANNUAL DISTRIBUTION OF DEMAND THROUGHOUT THE DAY IN NAMIBIA, 2005[4]



NamPower's Base Case forecast for electricity demand, shown in Exhibit I-4, illustrates that even under rather modest assumptions the demand for electricity will approximately double by 2020.

EXHIBIT I-4: BASE CASE FORECAST FOR ELECTRICITY DEMAND IN NAMIBIA[5]



Over the next few years, as the surplus from South Africa, traditionally meeting more than half the country's electricity demand, continues to fall, Namibia will need to look at new sources of supply. Exhibit I-5 shows the short term supply-demand balance for the country, assuming that both the Caprivi Link and Kudu are completed on time (2006 and 2008, respectively – note that these dates have been superseded since compilation of the graphic).

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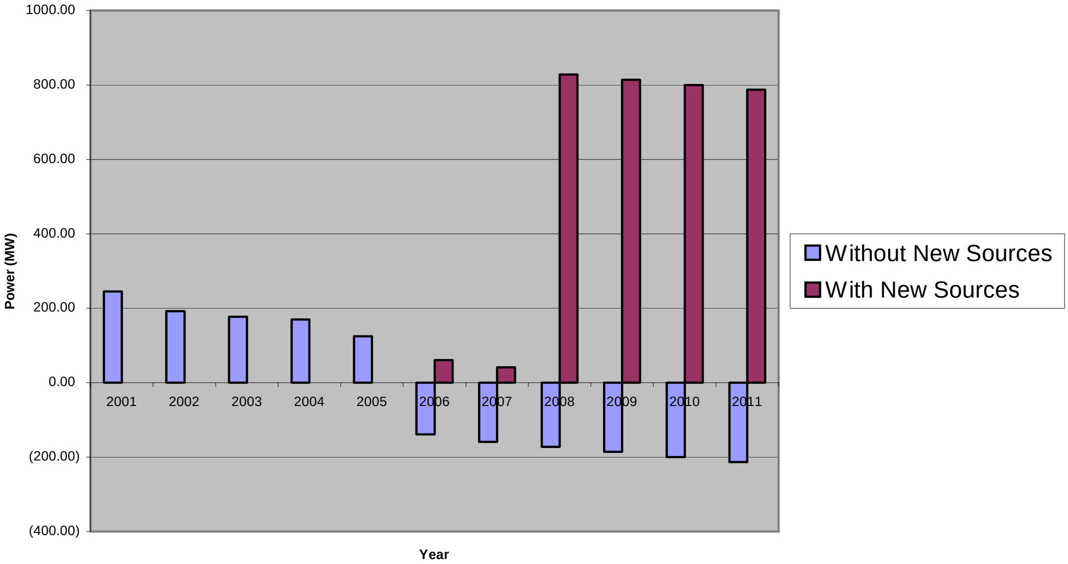
[4]. Source: ECB Demand Side Management Study, 2006
[5]. Source: NamPower, includes Skorpion Zinc load

EXHIBIT I-5: SHORT-TERM ELECTRICITY SUPPLY DEMAND BALANCE IN NAMIBIA[6]



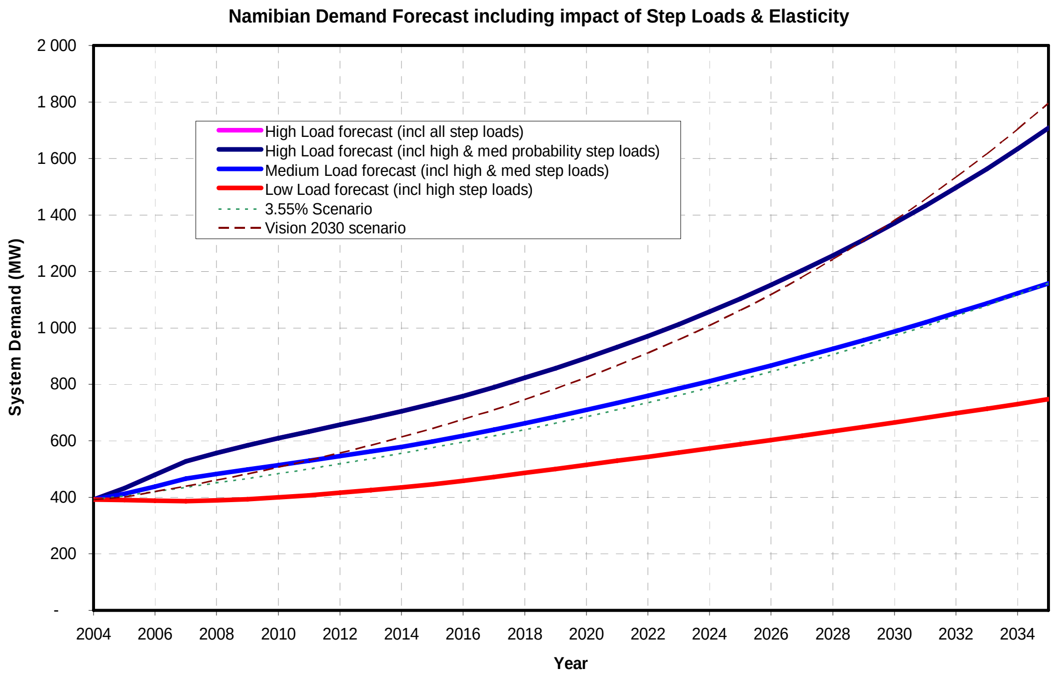
As the discussion just above indicates, the future demand for electricity depends critically on several key economic and social indicators: (i) overall economic growth; (ii) step load growth in mining and industry; and (iii) increased load (more customers and deeper demand) from residential users. These are all factors in the Vision 2030 scenario, so it is no surprise that success with the implementation of Vision 2030 will lead to more substantial increases in electricity demand than will slower-growth scenarios.

The low demand growth scenario in Exhibit I-6 represents load that is virtually certain to materialize. By 2020, the output from a new plant at least the equivalent of the Van Eyk plant will be needed to meet the anticipated additional load. However, it is anticipated that the Namibian economy should experience real economic growth of at least 3.5% over the same period. The two medium demand case forecasts in Exhibit I-6 show that even modest economic growth will generate more than 200 MW of additional demand (50% increase from 2005) by 2020. Finally, high economic growth, reflecting the successful implementation of the Vision 2030, would require more than the entire output of the Kudu power plant within less than 20 years to meet new demand.

The same factors that drive the domestic demand for electricity – population growth, mining activities, tourism, and rising affluence – are also present in South Africa and pose a sizeable challenge to Eskom, the main electricity supplier, in South Africa. Eskom has faced unprecedented difficulties in meeting demand growth and has unveiled an ambitious investment program (over US $16 billion) to significantly increase the generation capacity over the next ten years. Annex 4 contains an extensive exposition of the South African demand and supply balance over the next 10-15 years with the implications for Namibia as follows:

[6]. *Source: NamPower*

EXHIBIT I-6: RANGE OF ELECTRICITY FORECASTS OVER THE NEXT 20-25 YEARS IN NAMIBIA[7]



- Eskom will face even greater challenges meeting the country's domestic electricity demand over the next 10-15 years;
- Transmission capacity within South Africa needs to be significantly augmented in the short term;
- New generation stations are likely to cost more than the older technologies that they replace;
- Bringing old plants out of mothballs will likely lower the overall level of system reliability; and
- South Africa faces unprecedented challenges from shortages of skilled labor and project management to meet its stated construction goals and deadlines.

The possibility of continued reliance on South Africa is discussed at some length in Annex 4, which deals with the supply and demand issues in greater detail than presented in this Main Report. Annex 1 provides further details on Namibia's power sector background and key issues.

2. INSTITUTIONAL STRUCTURE

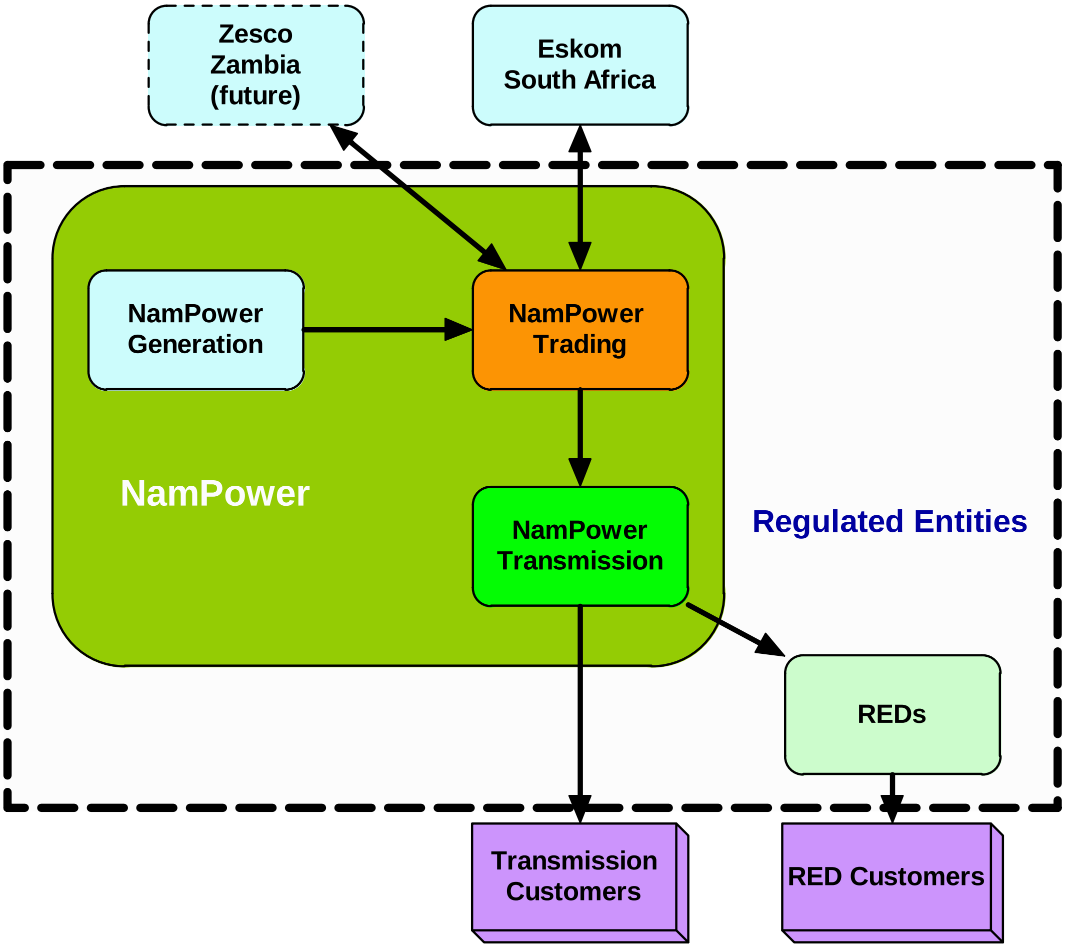
Description of Power Market
NamPower acts as an integrated generation and transmission company with its entity NamPower Trading acting as the electricity system's Single Buyer and only trader thus far. This entity also imports from and exports to neighboring countries (South Africa and Zambia). NamPower Generation's output is also purchased by this unit.

NamPower Transmission then sells the power on to a small number of transmission customers. These are a mix of large users (mostly mines and water pumping schemes),

[7]. *Source: NamPower*

the Regional Electricity Distributors (REDs), and an array of smaller consumers who, for legacy reasons, are connected directly to transmission substations. There are also some cross border customers in Angola, Botswana and South Africa where NamPower Transmission supplies power at distribution or sub-transmission level. This is illustrated in Exhibit I-7.

EXHIBIT I-7: CURRENT NAMIBIA ELECTRICITY SYSTEM STRUCTURE



The REDs then distribute and sell power to end users in their respective areas of supply. They serve approximately 150,000 end consumers, the vast majority of which are domestic users. There is also one exception to the system described above, Skorpion Zinc, power for which is effectively wheeled by NamPower on behalf of Eskom. In order to ensure firm supply and a competitive price, this arrangement was negotiated to enable the development of the operation in Namibia. The contract with Eskom contains a clause allowing the contract to be switched to a Namibian supply source after seven years – this clause may have been included with the Kudu development in mind and may present an opportunity.

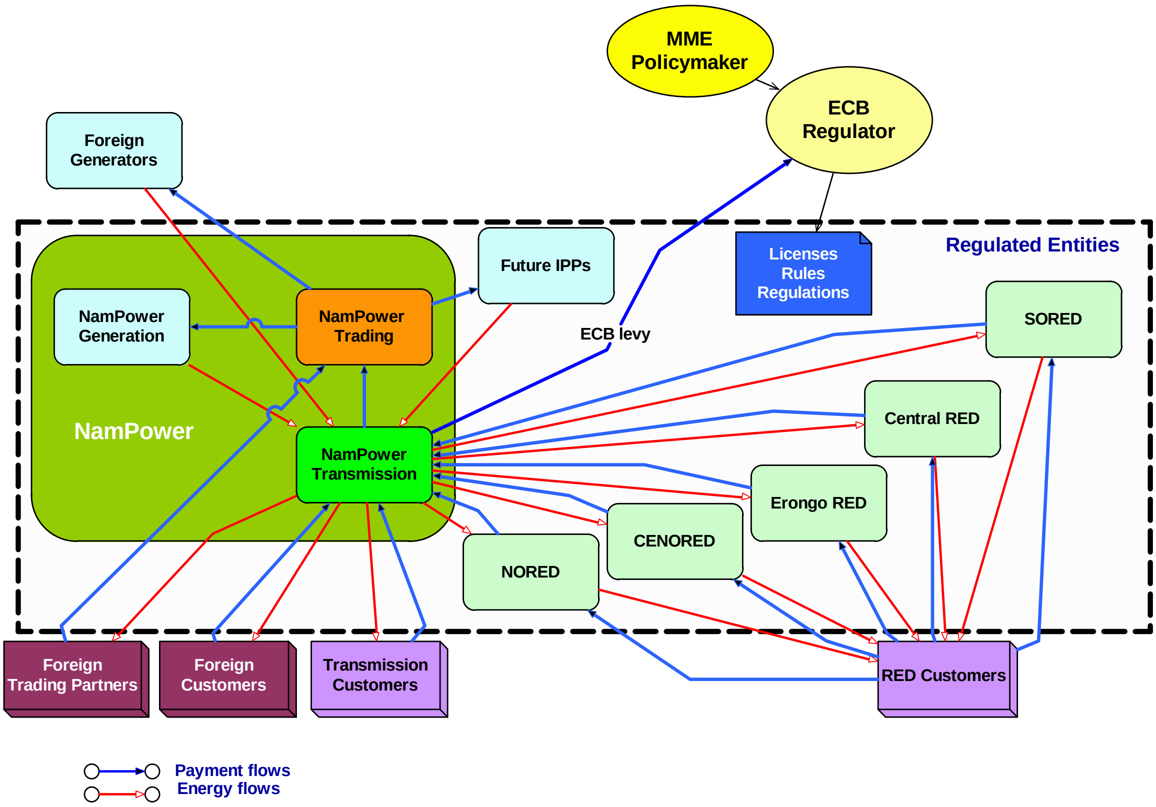
Description of Market Relations

Market relations in Namibia are largely contract based. NamPower has agreements in place with Eskom for the main trading activity. This agreement is largely modeled on the Southern African Power Pool (SAPP) principles. NamPower also has power supply agreements with all its transmission and distribution customers. Except for Skorpion Zinc, these agreements are largely standardized. The REDs have a slightly different form of contract from those used for end-use consumers.

Roles of Different Government Institutions Including Regulators

The MME as policy maker has made clear policy statements in favor of an open, competitive and transparent market which promotes private sector involvement and investment. The ECB as regulator, as mandated by the Electricity Act, also enables an open market through the licensing regime. The relationships among the various power sector institutions is shown in Exhibit I-8 and is described more fully in Annex 4. Exhibit I-8 represents the expected institutional arrangements that will be needed to implement the current Electricity Bill (see Annexes 4 and 5 for a description of the Electricity Bill of 2006). Most of these changes have already been made, but a few await additional legislation.

EXHIBIT I-8: POST-RESTRUCTURING ELECTRICITY SYSTEM, NAMIBIA[8]



Current State of Restructuring

The major initial restructuring objectives of the Government of Namibia have been achieved to a reasonable degree. NamPower has been ring-fenced into business units that carry separate financial accounts and operational controls. While it can be argued that not enough separation has been created between these business units to really consider them as operating independently, there is significant movement toward greater transparency of funding and operations.

In the distribution sector, three REDs have been formed and have commenced operations, namely NORED (since 2002), CENORED (since 2005) and Erongo RED (since 2005). Development of Central RED and SORED is progressing at a slower pace than NORED, partly due to disagreements between stakeholders and partly due to

[8]. *Source: Compiled by CORE and EMCON team based on stakeholder discussions*

delays in promulgating changes to the Electricity Act, which are deemed to be necessary to properly empower the REDs.

Implementation of a fully-functioning Single Buyer Market Model has not yet been completed. The ECB and NamPower, as main players, have yet to reach consensus on the specific form and functions of a single buyer concept. The trading function is, therefore, still embedded in NamPower in a not very transparent manner. Development of a market model that might more effectively permit IPPs and other market participants is described in more detail in Section III A, which covers the recommended market model.

3. KEY REGIONAL ISSUES

The most important regional electricity issues are (i) the decline of the South Africa surplus in generation capacity, described above, which affects the entire balance of supply in the region; (ii) the increasing sophistication of trading and physical links between and among SAPP members; and (iii) the need for a financial and economic adjustment to higher electricity prices. These issues color all of the discussions of demand, transmission links between countries, and investment in new capacity. The key regional issues also affect the nature and the pace of electricity restructuring, since the activities of Namibia's major electricity trading partners critically affect the types of trading systems that can be feasible within Namibia.

Regional restructuring of the national electricity sectors is at different stages of development. In South Africa, the most important regional player in the power market, efforts have been made to separate Eskom's generation and transmission businesses. While it was originally intended to create a Multi-Seller Multi-Buyer (MSMB) market on the model of NordPool, Eskom has thus far not managed to implement this new institutional setup and it still dominates the regional market as a combined transmission and generation entity. South Africa is also busy in establishing REDs – the process there has followed a rather different path from what was done in Namibia, and progress to date has been limited. The process has, in fact, been started, stopped again due to significant political and legal problems, and has been re-started with efforts to establish RED1.

In other surrounding countries there is no significant development towards REDs or separation of generation and transmission business of the national utilities. Regulators have been established in a number of countries, and others are in the process of being established. South Africa, Namibia and Zambia have well established regulators, with Mozambique and Zimbabwe in the process of establishing their respective regulators. Botswana and Angola do not yet have electricity regulators.

In addition to the structural issues regarding the power sector, Namibia also has a handful of border discussions and agreements that critically affect whether certain IPPs can ever be built. These border issues concern the following:

- Botswana, where residents along the Linyanti River have protested Namibia's planned construction of the Okavango hydroelectric dam on Popa Falls due to water rights issues and other social and environmental considerations;
- South Africa, where a managed dispute over the location of the boundary in the Orange River have prevented the construction of a number of smaller (~ 20 MW each) power plants on the Orange River; and

- Angola, where the absence of an agreement regarding riparian rights to the Kunene River has so far limited expansion of hydro plants in the Northern part of Namibia.

The next steps in the Namibian power sector reform process will be the following:

- Promulgation of the new Electricity Bill planned for late-2006;
- The completion of the RED formation process with the establishment of the last two REDs (probably 2007);
- Establishment of a Single Buyer Market or another market alternative; and
- Movement towards incentive-based regulation.

C. TERMS OF REFERENCE FOR THE TECHNICAL ASSISTANCE

The Terms of Reference for this technical assistance provided by the U.S. Trade and Development Agency to the Electricity Control Board, Namibia were included in the Grant Agreement and provided to all prospective bidders in the Request for Proposal. The key objectives of the Terms of Reference were as follows:

- Development of a formalized energy market model with a focus on how to facilitate investments by IPPs and/or Independent Transmission Companies ("ITCs") in Namibia.

- Addressing the current capacity deficit and security of the supply situation while allowing flexibility for a future move towards wholesale or retail competition in the market.

- Recommendations on one or more options for private sector participation in the Namibian energy sector and then development of framework strategy documents to implement the recommended private sector promotion model.

The Terms of Reference include specific tasks and deliverables. This Final Report provides a compilation of all activities conducted under the various tasks. It includes CORE International's findings and recommendations for the next steps in the process of creating an enabling environment for private sector participation in Namibia's power sector. The Final Report consists of two volumes – Volume I: Main Report and Volume II: Annexes. A total of 12 annexes are included in Volume II which document all materials developed for the various workshops for officials and various stakeholders. The annexes in Volume II also include our analyses of various power market, pricing, and regulatory issues. In addition, Volume I: Main Report also includes a stand-alone Executive Summary which includes sufficient details to facilitate executive level deliberations and discussions.

Annex 2 includes a complete copy of the Terms of Reference for this Technical Assistance.

During the course of conducting this technical assistance, the CORE Team held a large number of individual and group meetings. Also, a number of working sessions and workshops were conducted for officials from the various stakeholders in the energy sector.

Annex 3 includes a complete list of contacts.

II. POWER SECTOR INVESTMENT REQUIREMENTS AND PLANNING

A. CURRENT POWER SECTOR INVESTMENT PLANS

The current power sector investment plans in Namibia largely vest within NamPower and can be divided into transmission and generation projects.

Generation
As discussed in more detail in Annex 1 and Annex 5 there are a number of generation projects under consideration. These projects are at various stages of development and have various issues associated with them. None of the listed generation projects has reached financial closure and all are, therefore, still pending at the time of writing of this Report.

Exhibit II-1 lists the known generation projects and briefly summarizes their status:

EXHIBIT II-1: CURRENT STATUS OF POWER GENERATION[9]

Type	Capacity	Name	Remarks
Thermal	800MW	Kudu	The Kudu gas-to-power project has been under development for a number of years and of all generation projects is the furthest advanced. It is currently pending agreement on a few critical issues such as the gas price, the foreign exchange risk associated with the gas development and a PPA with Eskom.
Hydro	360-500MW	Baines	The lower Kunene River (excluding Ruacana) has an energy conversion potential of 1600 MW if all the major waterfalls and water rapids are developed. Epupa and Baines sites have been investigated and each site has the potential of between 360 and 500 MW depending on the envisaged Load factor. Both stations could be developed as Base Load stations or Merchant plants. The major risk is that the Kunene River is the Border between Namibia and Angola and no development can take place without the involvement of Angola.
Hydro	100MW	Orange River	There is a potential of 100 MW run-of-the-river power stations (12 x small plants). The key barrier, however, is that the Border between South Africa and Namibia is still defined as the northern flood line of the river i. e.; the whole river belongs to South Africa.

9. Source: Compiled by CORE and EMCON team based on stakeholder discussions and information obtained from NamPower

Hydro	20MW	Popa Falls	This site is located on the Okavango River inside the Namibian border. However, the utilization must still be approved by OKACOM (the River-commission of all bordering countries). The station has a potential of 20 MW and would be a run-of-the-river station. The major barriers are the very small size of the plant and the environmental sensitivities of the Okavango delta situated in BOTSWANA.
Thermal	27MW	Walvis Bay	OCGT Power plant situated at Walvis Bay: This will be an emergency peaking plant to bridge the very challenging years until either or both Kudu and Caprivi interconnections are in place (2007 until 2009)
Thermal	50 – 400MW	Walvis Bay	50 – 400 MW Coal Fired Power Station situated in Walvis Bay. This plant is considered in case Kudu and Baines cannot be constructed or should very long delays occur.
Wind	20-50MW	Luderitz	At least 20MW of wind generation potential has been identified at Luderitz in a project commonly referred to as the Luderitz Windpark. An attempt was made by NamPower in 2003 to obtain a generation license for a small Windpark (3-6MW), however, this failed for largely commercial reasons.

The above generation projects are scattered across Namibia geographically as can be seen from the map provide in Exhibit II-2.

There are private efforts currently at early stages for the following potential generation projects:

- Reviving the Luderitz wind park (possible foreign investor);
- Invader bush to power project – potentially a larger number of small (500kW) generators fired using invader bush on commercial farm land.

Transmission
There are at least two transmission projects that are currently on NamPower's books which are intended at least partly to address the demand and supply balance in Namibia, to widen the scope for imports from sources other than Eskom and to enhance Namibia's position as a trader of electricity in the region. Exhibit II-3 describes the transmission projects' status in Namibia.

The main currently planned transmission extension is the Caprivi link, which is a HVDC project intended to link the Namibian system with Zambia and Zimbabwe. The link is intended to have a capacity of up to 600MW and will enable NamPower to trade electricity between Zambia, Zimbabwe and other countries in the North and South Africa in the South. It will also make Namibia less dependent on imports from South Africa by opening up new supply options from the North, and will also reduce Namibia's exposure to the South African transmission grid which currently has significant constraints threatening supply stability to Namibia in the short to medium term.

EXHIBIT II-2: GEOGRAPHICAL DISTRIBUTION OF CURRENT POWER GENERATION FACILITIES IN NAMIBIA[10]

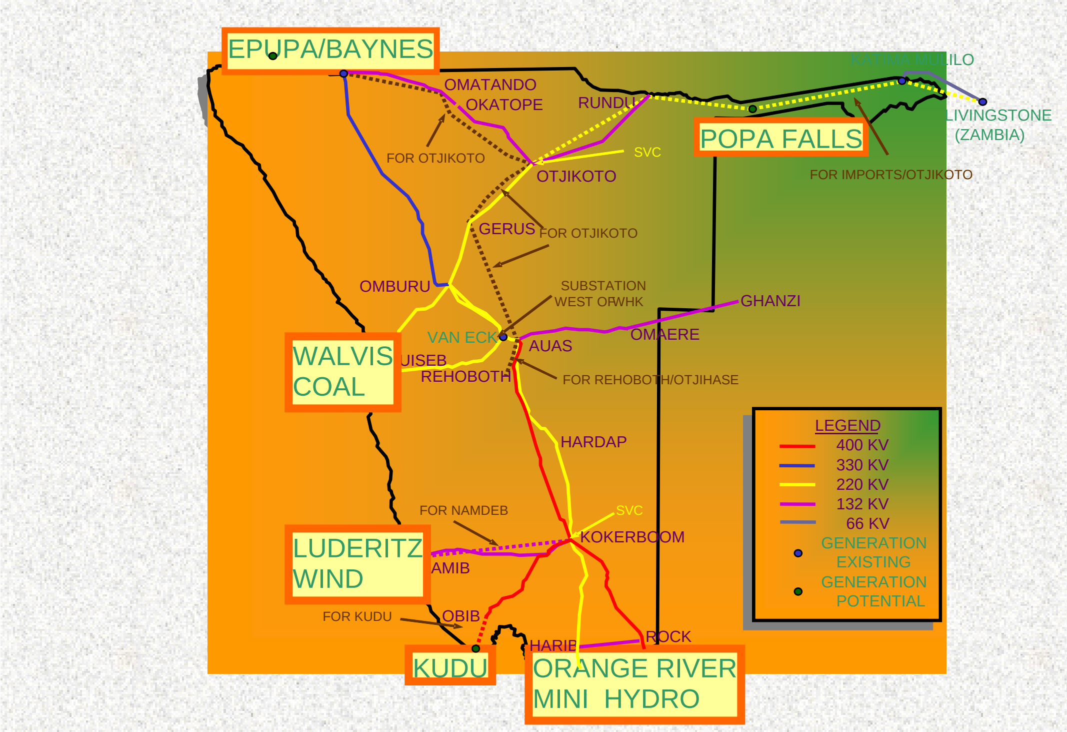


EXHIBIT II-3: STATUS OF TRANSMISSION PROJECTS IN NAMIBIA[11]

Name	Capacity	Remarks
Caprivi Link HVDC	600MW	The Caprivi Link is a HVDC project intended to link the Namibian system with Zambia and Zimbabwe. The link is intended to have a capacity of up to 600MW and will enable NamPower to trade electricity between Zambia, Zimbabwe and other countries to North and South Africa in the South. It will also make Namibia less dependent on imports from South Africa by opening up new supply options from the north, and will also reduce Namibia's exposure to the South African transmission grid which currently has some significant constraints which threaten supply stability to Namibia in the short to medium term.
Westcor	In the Planning stage	Namibia is part of the Westcor project which is intended to bring power from Inga in Democratic Republic of Congo (DRC) to South Africa and surrounding countries. Westcor is a grand project involving multiple countries and their utilities and is

[10] Source: NamPower Graphic modified by CORE and EMCON team
[11]. Source: Compiled by CORE and EMCON team based on stakeholder discussions and information provided by NamPower

		expected to take a significant amount of time to be realized. It would place Namibia strategically as a trader and key link in the West African transmission corridor.
Namib – Kokerboom 132kV AC	20MW	The second 132kV link between Kokerboom and Namib in southern Namibia is currently under construction and is being built primarily to serve additional demand in the Luderitz area. It is also a critical factor for the development of the Luderitz wind park since it increases the connection capacity between the planned wind park site and the main grid. From this perspective it may prove that a higher capacity line might have been warranted, since the total capacity with both 132kV lines is well below what is believed to be a realistic wind generation potential around Luderitz.

B. LEGAL ENVIRONMENT FOR IPPs IN NAMIBIA

The basis for the IPP business model is the legal description of the sector – relevant legislation and the roles, rights and responsibilities of the various parties. The legal foundations for the REDs and their rights and responsibilities as well as the appropriate legislation are described in Annex 5. This legal analysis and description covers not only the relevant legislation for the various governmental bodies, but also contains an analysis of the ongoing legal steps in the electricity sector restructuring process. In particular, the need for the government to issue new types of licenses (e.g., trading, distribution, etc.) is also covered in Annex 5.

There are three main legal acts that govern the IPP environment in Namibia and two additional acts that are under parliamentary consideration. These acts are:

1. Electricity Act of 2000
2. Foreign Investment Act of 1990
3. Competition Act of 2003
4. Electricity Bill of 2006 (pending)
5. State-owned Enterprises Bill of 2006 (promulgated since compilation of this report)

The Electricity Act of 2000 established the Electricity Control Board, providing the basis for the regulation of the electricity sector. The Act not only establishes the rights and responsibilities of the ECB, but also specifies the issuance of licenses for various electricity sector activities. As per the provisions of the Act, the ECB is not permitted to directly undertake any of the essential market activities in electricity – generation, transmission, sales, and distribution – but to issue licenses to various parties. The Act also provides for ECB supervision of environmental impact analyses for all new licensed activities and investment.

The Foreign Investment Act of 1990 sets forth the rights and responsibilities of foreign investors. For the IPP business the most important provisions of the Act are (i) no local investor requirement; and (ii) straightforward expropriation provisions.

The Competition Act of 2003 governs the enforcement of market exchange principles and defines various types of criminally restrictive business practices. The Act is relevant to the restructured electricity market and to IPPs since its provisions will probably govern any legal investigations into restrictive activities on the part of one or more electricity market participants. The most important provisions of the Act for the IPP business are the ones that (i) govern the relationship of related parties in transactions; (ii) proscribe price fixing; and (iii) prohibit the cartelization of industrial sectors.

The Electricity Bill of 2006 is expected to replace the Electricity Act of 2000 in its entirety. The primary intent of the Bill is to provide for the restructuring of the country's electric power system into its functional segments. The three key features of the Bill are the addition of electricity trading as a licensed activity, a strengthening of the ECB's power to issue rules governing the behavior of the market participants and the establishment of a firm legal basis for the Regional Electricity Distributors (REDs). The Bill is expected to be approved late in 2006 or early in 2007.

The State-owned Enterprises Bill of 2006 represents another effort to bring the country's state-owned enterprises (SOEs) into more effective governance with regard to oversight, performance and finances. Not only are such SOEs as NamPower brought under the purview of a newly-created SOE Governing Council, but certain regulatory bodies, including the ECB, will be governed by this law as well. The Bill is in an advanced stage of preparation and should be enacted in early 2007. The Governing Council will oversee business plans (mandated), budgets, priorities, salaries and will enter into a performance agreement with each SOE that comes under its purview. This Bill has been promulgated since writing of this report.

C. CURRENT POWER MARKET MODEL

The Namibian Electricity Supply Industry (ESI) is regulated by the ECB subject to the powers vested in the regulator under the Electricity Act (Act 2 of 2000). Under the Act, any person engaged in the generation, transmission, distribution, supply, import or export of electricity must obtain a license from the ECB for such operations. There are well defined processes for such license applications and the general license conditions have been developed and are generally well understood.

NamPower Transmission Trading, at this point, is the only trader in the country. Trading with neighboring countries (currently South Africa, and future Zambia and Zimbabwe) are contracted and managed by this entity. NamPower Generation's output is also effectively purchased by this entity.

NamPower Transmission then sells the power on to a small number of transmission customers. These are a mix of large users (mostly mines and water pumping schemes), the REDs and an array of smaller consumers who, for legacy reasons, are connected directly to transmission substations. There are also some cross border supplies where NamPower transmission supplies power at distribution or sub-transmission level to Angola, Botswana and South Africa. In some cases this power is wheeled through RED medium voltage networks.

The REDs then distribute and sell power on to end users in their respective areas of supply. They serve approximately 150,000 end consumers, the vast majority of which are domestic users.

Exhibit II-4 provides a schematic of the post-restructuring electricity market structure in the country.

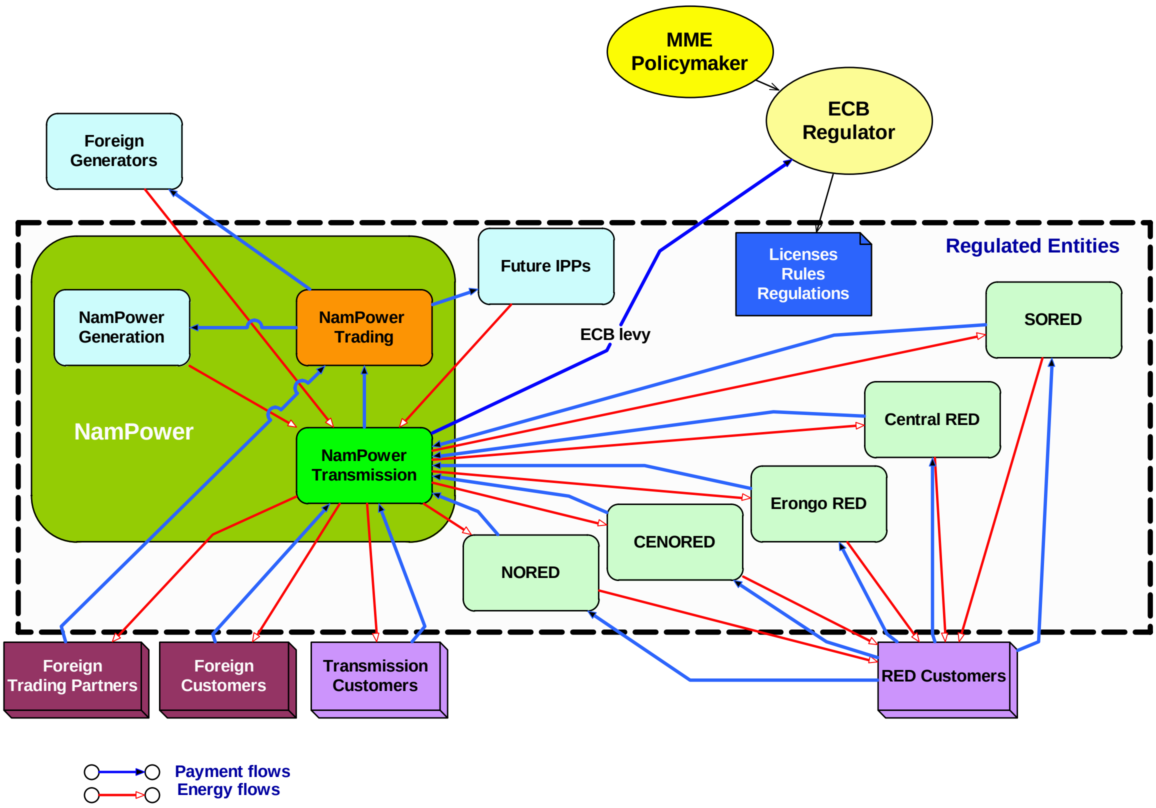
There is also one exception to the above system, namely Skorpion Zinc, for which power is effectively wheeled by NamPower on behalf of Eskom. In order to ensure firm supply and a competitive price this arrangement was negotiated to enable the development of the operation in Namibia. The contract with Eskom contains a clause allowing the contract to be switched to a Namibian supply source after seven years – this clause may have been included with the Kudu development in mind and may present an opportunity for local generation (depending largely on price competitiveness and security of supply considerations).

Market relations are largely contract based. NamPower has agreements in place with Eskom for the main trading activity. This agreement is largely modeled on SAPP principles. NamPower has more recently negotiated agreements with Zambian and Zimbabwean utilities for purchase of power, however this is very recent, and it is not clear whether those agreements have been signed or will be signed.

NamPower also has power supply agreements with all its transmission and distribution customers. Except for Skorpion Zinc, these agreements are largely standardized. The REDs have a slightly different form of contract from those used for end consumers.

The MME as policy maker has made clear policy statements in favor of an open, competitive and transparent market which promotes private sector involvement and investment (Energy Policy White Paper, 1998). The ECB as regulator, as mandated by the Electricity Act, also enables an open market through the licensing regime.

EXHIBIT II-4: POST RESTRUCTURING ELECTRICITY SYSTEM IN NAMIBIA



Some of the issues and shortcomings of the current market, when considering the promotion of IPPs, have been identified as the following:

- There is no independent Trader (or Single Buyer)

  - NamPower currently undertakes this function with its Transmission Trading unit; however this unit is not independent from NamPower which raises issues for any process where NamPower may compete with others for a new power project.

  - The small size of the Namibian market makes it difficult to justify the establishment of a legally and financially independent trader, especially since the balance sheet of NamPower is needed as a backing for the risks associated with the trading function.

- Namibian electricity prices are historically low compared with typical international prices due to the cheap imports from South Africa made possible by the historic over-capacity available in that country through fully depreciated generation investments.

  - These low prices create a barrier for new entrants whose costs will invariably be higher than current generation costs. However, price projections indicate that this issue is likely to be resolved within a few years by rising import prices from South Africa and other sources which will make new local generation projects much more feasible.

  - There are concerns about the impact of these price increases on the local economy and especially on the competitiveness of Namibia vs. South Africa. While this is a valid concern, it is also clear that sizable price increases are unavoidable if the economy and the Electricity Supply Industry (ESI) are to remain on healthy financial footing.

- Local Authority (LA) taxation of electricity is putting RED retail prices under significant pressure, which puts in question what growth can really be expected in local end consumption, especially from the residential sector which accounts for a significant portion of local consumption of electricity.

  - A normalization of LA taxation (leading to an overall reduction thereof) would create significant room at the retail price level to absorb some of the generation and transmission price increases which are being anticipated. This would contribute to making IPP projects more viable by increasing the likelihood of consumption growth and stability in the retail sector.

- Distribution and Supply restructuring is not complete. This is casting doubts over the status of the retail price of electricity, which in turn casts doubts over local consumption growth, the key driver for mobilizing IPP projects of various sizes.

  - There is a lack of stability at the consumer end of the electricity supply chain which should be addressed in order to reassure potential generation investors that the local retail market for electricity is stable and foreseeable.

- Eskom and NamPower are in a position to exercise market power through their historically entrenched monopoly roles and positions.

- Under the current market model, they can refuse to pay the price demanded by a prospective generator. Since any new generator needs to negotiate a PPA with NamPower Trading (except for very small IPPs who might negotiate PPAs with the REDs), a gap is left where NamPower can exert significant influence.

- Eskom and NamPower are used to exercising control and are naturally averse to letting go of this control, despite government policies in both countries favoring flexibility and openness. This may influence their behavior, and a change is required to enable more open access for IPPs.

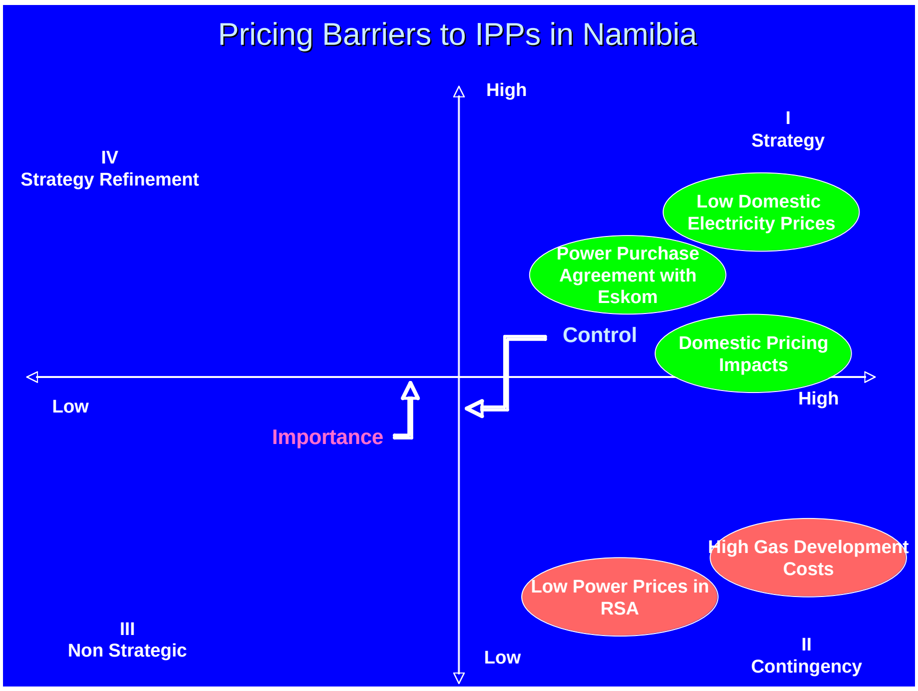
D. ROLE OF IPPs AND PRICING BARRIERS TO IPPs

At the beginning of this engagement, the CORE Team and ECB identified barriers to IPP development in Namibia. These barriers were split in a number of ways – controllable or not, important or not – that could facilitate the development of measures to remedy the barrier or otherwise mitigate the underlying risk to IPPs in Namibia.

Most of the findings from the project and the recommendations for future activities on the part of the ECB, NamPower, MME or others follow directly from the identification and categorization of barriers to IPP development. This section of the report focuses on the pricing barriers to IPPs and discusses measures that can mitigate the risks posed by these barriers. Kudu Power Project has been used only as an illustration as it is large project in a small power system in Namibia and inherently includes many barriers that need to be identified and controlled.

Using the same framework for categorizing barriers as was used from the start of the project, the CORE Team found that pricing barriers were generally important to the success of IPPs and varied chiefly by their degrees of controllability; that is, whether they could be mitigated in a strategic manner or dealt with as contingencies. Exhibit II-5 shows the pricing barriers to IPP success that have been identified in Namibia.

EXHIBIT II-5: PRICING BARRIERS TO IPPs



IPPs require critical attention from regulators and government policymakers, especially in a small system such as that in Namibia since a large project can have a profound influence on the overall level of pricing. Many analyses of international IPP experience have shown repeatedly that pricing problems are the most reliable way to doom an IPP project to failure. For that reason, the CORE Team has spent considerable effort in this area and provided further detailed discussions as shown in Annexes 6 and 7. Annex 6 addresses in greater detail the nature of pricing barriers and suggestions to mitigate the risks arising from such barriers. Annex 7 is more technical, and covers the pricing provisions for IPPs along with their implications for retail tariff policies.

Exhibit II-5 shows five pricing barriers to IPPs as follows:

1. Low domestic electricity prices;
2. Absence of a PPA with Eskom[12];
3. Concern about domestic pricing impacts of a new IPP;
4. High gas development costs for Kudu; and
5. Low power prices in South Africa.

Mitigating measures for each barrier vary with the controllability of that barrier. Low domestic prices, certainly a barrier to acceptance of higher prices for purchased power, can be remedied entirely by actions taken in the context of Namibia's own regulatory institutions. Indeed, the country is now taking steps to transition the tariff system to one that reflects costs on a forward-looking basis, rather than relying on historical and depreciated costs to set tariffs.

Continuing disagreements with Eskom about prices in a sales agreement for the Kudu Project output constitute another important barrier. The reluctance of Eskom to go forward with a PPA for Kudu is itself a result of a less controllable barrier from the Namibian perspective, the low power prices in South Africa. Although nothing much can be done by NamPower or ECB to change electricity prices in South Africa, the analysis of cost trends in that country indicates that prices are likely to rise significantly from their current low levels.[13] Many highly correlated factors would need to succeed in the very short-to-medium terms for there not to be significant readjustments in that country's electricity sector. In particular, the costs of new mines, cleaner coal technology and mine restoration, as well as technology and project management services, are significantly greater than they were when the current crop of Eskom coal-fired plants was constructed in the 1970s.

The CORE Team believes that, absent a severe reduction in demand for minerals exports from South Africa demand for electricity in that country will continue to rise more quickly than new generating stations can be constructed. The end result of this process, an aging and inefficient generation mix, augmented by very expensive combustion turbines, will induce higher price levels in the country. With new construction tending toward international price levels for output and existing generation capacity rising in cost as well, the output from a large power project such as Kudu, which has relatively high, but stable prices, may be increasingly attractive. In addition, the availability of additional supplies for the Western Cape Province may prove attractive to the distribution company in that region of South Africa, offsetting some of the opposition by Eskom to a PPA for Kudu or some other large power project. The value of unserved electrical energy is

[12]. As of end-November 2006 this barrier has been partially mitigated with a Heads of Terms. No details are available outside NamPower.
[13]. The question of South Africa's electricity expansion plan has been discussed at length in Section I of this report.

almost always significantly greater than the cost of supplying it. So unless it is absolutely certain that Eskom can meet all of the RSA domestic demand, alternative supplies that are a bit higher, say gas-fired plants in Namibia, will find a ready market in the region.

In some cases, mitigating a risk, such as the one posed to Namibian IPPs by low power prices in South Africa, cannot be tackled head-on. Rather, the barrier, which has become a risk to the success of Kudu or any other large IPP in Namibia, must be either reformulated or circumvented. Reformulation means focusing on the increasing costs in the South African market and stressing the reduction in pricing risk overall from stable Kudu prices. Circumvention means changing the object of the PPA effort to the Western Cape Province Distribution Company rather than Eskom itself.[14] It is well-known in the Region that the Government's directives to Eskom to build new generating capacity belie its claim to not need the output of the Kudu Project or any other large power project in Namibia. It is certainly possible to use that information to try to sell the output from Kudu to Cape Province as evidence accumulates on the difficulties faced by Eskom in expanding its generation mix to meet future demand.

High gas costs for the Kudu field illustrate another largely uncontrollable, though extremely important barrier that may be present for other large power projects as well. This barrier can only be partially overcome through deliberate effort. That effort centers on selling the project on the basis of its price stability. Given all of the factors now operating in South Africa to drive up future electricity generating costs, a stable, but higher level of cost from a project such as Kudu will reduce the overall level of pricing risk compared with a number of other available alternatives – LNG imports, combustion turbines using oil, new coal mines with new combustion technology. Recent work in the field of financial portfolio theory has been applied to investments in power generation portfolios.[15] As a general rule, lower average cost generators with high fuel price risk raise the overall risk in the generation mix more than the periods of low prices benefit consumers.

The final pricing barrier, concern about the domestic pricing impacts of higher priced independent power sources, can be mitigated to some degree through reformulation or splitting the problem into smaller and more easily managed pieces. The elements of such an effort could include a public outreach program on the part of the Government and ECB. These efforts will need to stress the importance of reliability from domestic generating sources along with price stability. Other putative benefits of IPPs for the country – jobs, development of domestic resources, construction outlays – can all be touted if the cost differential between domestic supplies and imports remains small.

Overlaying all of the individual pricing risks is the great risk of almost every gas or oil based IPP project. When fuel prices rise, the costs must be passed through. If the domestic pricing system is fully adjusted to cost pass-throughs of this type, then the process is relatively simple. Unfortunately, many countries wish to attract IPPs *because* their domestic pricing systems will not support new capacity investments. In such cases, the risks to the project and/or to the government are extremely grave and the project

[14]. CORE understands that such sales are not now permitted. However, pending changes in the legal environment for electricity in South Africa will enable the types of sales discussed in this section.

[15]. The type of risk that is most damaging and is certainly present in the Eskom expansion plan is called correlated risk. This is risk that is related to other risk factors. For example, the price risks of using oil to generate electricity are not much mitigated if one changes to LNG, since the price of LNG depends heavily on the price of oil products. Those two prices are said to represent correlated pricing risks. Similarly, engaging in heavy engineering construction at a time when many other industries with similar needs also wish to expand will give rise to correlated risk in construction costs – gas fields, oil wells, oil refineries, power plants, mines – all depend on the same, or similar, set of engineering and construction services.

may fail as a result.[16] Historically, when fuel prices and the requisite tariff adjustment processes move out of synchronization with one another, there are a limited number of possible outcomes, most of them very undesirable:

1. The country's regulator can redesign the tariff, inserting appropriate adjustment clauses to accommodate changes in the fuels market;
2. The regulator can try to "jawbone" the IPP operator, reducing the frequency, if not the severity of pricing adjustments;
3. Pricing adjustments take place, but at too slow a rate to maintain the profitability of the project, resulting in loss of reliability;
4. The Government can promise to pay for the additional fuel costs separately, in effect guaranteeing a fuel adjustment clause even when none exists; or
5. The Government can purchase the fuel, shifting 100% of the fuel price risk onto the taxpayers.

Annex 7 provides a detailed discussion of cost pass-through provisions. These provisions are intended to avoid the types of governmental or project failures that have formed such an important part of the history of IPPs. The CORE Team recommends that ECB and NamPower maintain close coordination when negotiating PPAs so as to keep prices paid for power and retail tariffs in reasonable synchronicity.

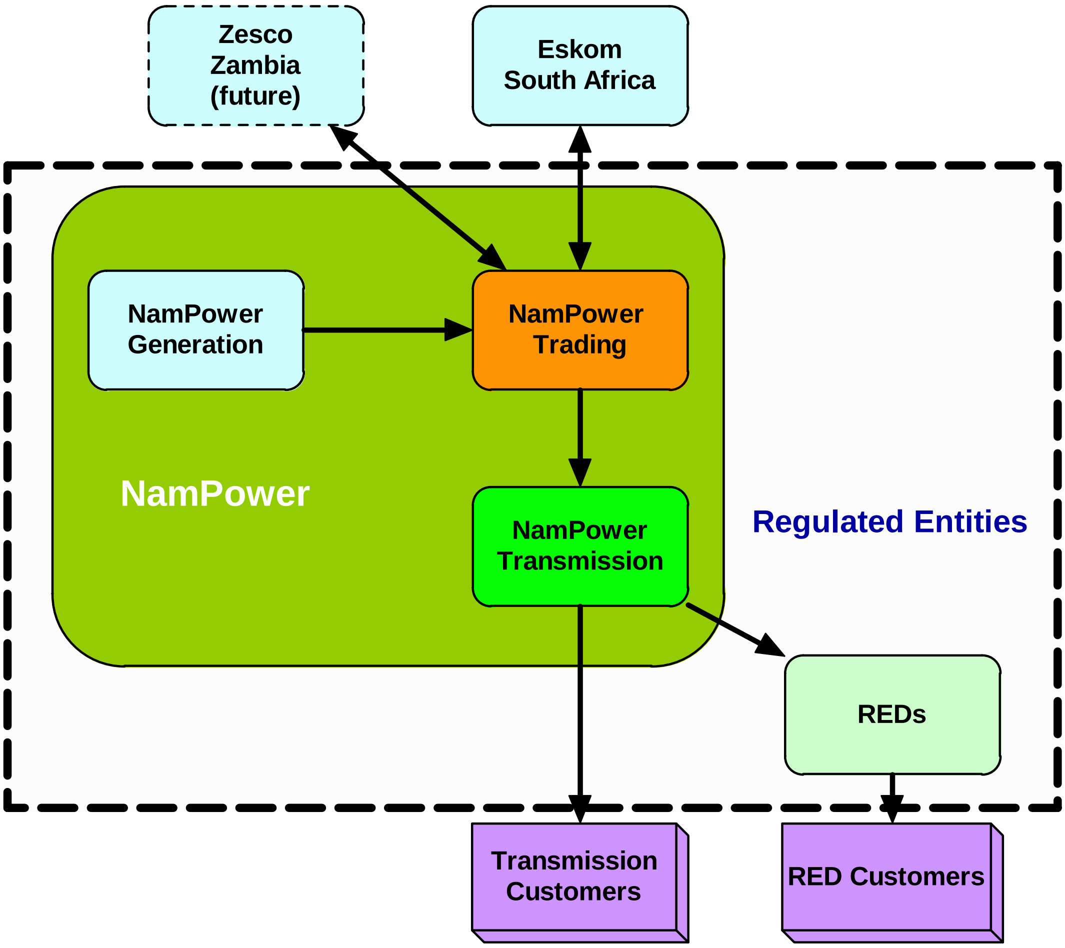
[16]. *This issue is treated in extensive detail in Annexes 8 and 9 of the Second Report.*

III. KEY FRAMEWORK MODELS FOR IPP DEVELOPMENT

A. POWER MARKET MODEL

Any large power project in Namibia including Kudu or some smaller project must fit into the institutional and regulatory context of the country's electricity sector. At the present time this means that the market operator, NamPower, is the same entity as the chief customer. Exhibit III-1 provides an illustration of Namibia's current electricity sector structure.

EXHIBIT III-1: CURRENT NAMIBIA ELECTRICITY SYSTEM STRUCTURE



As Exhibit III-1 shows, NamPower, in its roles as market operator, sole purchaser and seller of electricity and owner of network assets, still operates like a vertically integrated monopoly. The generation entity remains on the NamPower balance sheet. As the Regional Electricity Distribution Companies (REDs) continue to evolve, this responsibility will be fully removed from NamPower's remit.

NamPower's role in the electricity market has the potential to create problems once the country is forced to rely on IPPs to generate base load electricity. Experiences in other countries have shown that without proper structural changes in the electricity market and in the state-owned enterprise (NamPower, in this case), the following problems must be addressed:

- NamPower is the default single buyer and also the supplier of last resort; *meaning -*
- NamPower is the financially responsible party for PPAs due to the strength of its balance sheet.
- Without NamPower as the purchaser, IPPs will demand to have financial recourse to the Government; *therefore -*
- NamPower is the firewall between suppliers and direct government guarantee.

As long as IPPs are seen as the future of the country's generation system, a constructive way must be found to insulate the Government from the financial liabilities posed by power purchase agreements. This may require NamPower to shed or accept outside participation in or oversight of what are usually considered core functions of a power company: planning, procurement and operations (i.e., dispatch).

The issue of outside involvement in these core functions arises due to a perception that the ongoing affiliations between and among the former NamPower units will give rise to bias in these aspects of the NamPower operation. Experience in other countries has indicated that such affiliate transactions, effected through NamPower Trading as the single buyer, can lead to perceptions of:

- Bias in power development plan
- Bias in plant specification
- Bias in bid evaluation
- Bias in dispatch
- Bias in availability calculations

These perceived biases, all of which are seen by outsiders to favor NamPower's own plants or proposed investments, can reduce the willingness of investors to put funds into projects if they come to believe that there is systematic and ongoing discrimination against them. The ECB will need to play a vital role in overcoming these barriers. Exhibit III-2 provides recommended remedies to removing or reducing the barriers.

EXHIBIT III-2: INHERENT BIASES IN A SINGLE BUYER MARKET AND MITIGATION MEASURES

Problem/ Source of Bias	Mitigation Measure	Benefits	Problems
Investment Planning & Plant Specification	ECB active oversight & joint due diligence with NP	Reduces bias, Increases investor confidence	Taxing on ECB, no way to enforce compliance on NP
Bid Evaluation	ECB/NP due diligence exercise	Same as above	Increased chance of commercial information leakage
Plant Dispatch/ availability	Publish *ex ante* results of dispatch	Increased transparency & confidence	None

As the assessment of the suggested mitigation measures in Exhibit III-2 indicates, there are many options for the ECB and the government to increase investor confidence and transparency. And it should be noted that none of these measures relies on the Electricity Bill of 2006 for its legal power (Annex 5 provides a more complete discussion of the 2006 Electricity Bill). These measures may vary from current NamPower approaches to power acquisition and contracting methods. However, it is in the longer term interest of the country's electricity sector that as much transparency as possible be let into the process.

In particular, early coordination between ECB and NamPower may be necessary to forestall the "approve this PPA or else we will have blackouts" approach to PPA negotiations that has characterized many countries. While it is not necessary to have ECB involved in the negotiation process, it should be a matter of course to involve them in the oversight early in the initial negotiations, especially if there is going to be a major impact on tariffs or overall cost of supply.

In the bid evaluation phase the key regulatory issue is "prudence." In the end, the sums allocated to fuel and plant construction in a PPA must come from the ratepayers' pockets and assessing the prudential expenditure on behalf of those ratepayers is the quintessential regulatory task.

Many utilities claim to practice strict merit dispatch. However, public oversight is often useful as a check on the different interpretations of "merit" that can influence the plant dispatch order.

Thus, PPA design, prudence in bid evaluation, and strict merit dispatch represent fundamental good government responses to clearly articulated regulatory and public interests in the IPP and power procurement processes, when there is a single supplier to the retail market.

With some of these concerns, and others, in mind, the Electricity Bill of 2006 looks to remedy some of these potential sources of bias with further structural changes in the electricity market. One of the risks at this stage is the limited restructuring elsewhere in the region. As a price-taking entity, NamPower cannot afford to become a weaker negotiating entity vis-à-vis its suppliers or customers, especially Eskom. It is for that reason that the CORE Team believes that further significant unbundling and restructuring of the NamPower system should await complementary activities in neighboring nations, especially South Africa.

If the relevant choice for Namibia to accommodate more diverse sources of electricity is heavier regulation or more complex market structure, then CORE recommends a regulatory solution in the interim.

Utility De-Integration: How Have Things Worked Out?
In order to address some of the structural and potential conflict-of-interest issues that have arisen with regard to the role of NamPower, new legislation is under consideration for the power sector that would separate the operations of NamPower into its functional components. Whether such de-integration of NamPower is either effective or appropriate is beyond the scope of this study. Even so, the CORE Team feels obliged to draw the ECB's attention to some recent economic research on the costs and benefits of electricity system de-integration that stray from the consensus position on such de-integration as it has been adopted in many countries.[17]

[17]. *See Michaels, Robert J, Vertical Integration and the Restructuring of the US Electricity Industry, Washington, Cato Institute, 2006.*

The completion of the Kudu Project will require little institutional modification of roles and responsibilities[18]. This is because the interests of NamPower are generally aligned with those of the Kudu Partners as regards maximizing power sales from the project.

The success of Kudu or other large power projects (including large IPPs) sets the stage for other IPP programs involving smaller plants to proceed on a relatively quick basis. Once the medium term supply is secured, new projects using hydro, invader bush, wind or other sources can be evaluated solely in terms of merit. Once pricing issues are resolved, the remaining significant barriers for Kudu or other large IPPs revolve around the market risk of selling the output, especially to an uncertain South African market.

CORE recommends that NP remain a single buyer in structural terms, but that the Government consider bringing in other parties to mitigate some of the market risk.

As was noted above, investors in large IPPs tend to request government guarantees so as to offset both the commercial and financial risks of their projects. CORE believes that granting such assurances to IPP investors is unwise and will start the IPP industry off on the wrong foot.[19] Nevertheless, commercial and market risks are real and need to be mitigated somehow. One way to do this is to spread the risk among the most important non-governmental off-takers in the NamPower system, thereby distributing this market risk to others. CORE understands that this suggestion is a radical one to consider and that other alternatives may well prove suitable for Namibia. There is also the question of this proposal upsetting the planned implementation of a Single Buyer Market in the country, necessitating further restructuring delays for NamPower. However, one potential benefit of not having committed fully to an unbundling of NamPower is that Namibia retains the discretion to take up alternative approaches that make sense for the country in a changing external market environment.

Stated simply, CORE believes that it is possible to mitigate some of the market risk of IPPs by spreading it to new players. At the present time, major electricity customers in Namibia remain highly exposed to supply/price instability given the current supply context:

- Supply curtailments remain a real threat to the country;
- Prices cannot be guaranteed in the new supply environment; and
- Costs of a few days on backup power may well outweigh higher costs for reliable generation.

Given the likelihood of operating in an environment of increasing risks to major users, participation in the IPP off-take can reduce such risks at a price. The CORE Team makes the following recommendations in this area:

- Form a “Virtual JV” power plant with mining companies or other large private offtakers, *whereby*
    - Each company purchases output on Take-or-Pay basis with off-take responsibility for an amount in excess of the company’s needs, *resulting in*

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[18]. The proposed 400 MW coal-fired power station in Walvis Bay would pose market risk issues similar to those of Kudu unless there is a very large off-taker (say, a smelter) to mitigate most of the market risk.

[19]. Government guarantees were discussed extensively during the second field mission by the Team’s attorney, Professor Thomas Heller. International experience, detailed in the Stanford IPP report provided to ECB separately because of its large size amply demonstrates the pitfalls of government guarantees to IPP developers.

- Sales of excess power by off-taker to SA or SAPP with NamPower Trading as sales agent, so that
- Therefore, NamPower reduces some of the risk for off-take.

Exhibit III-3 and Exhibit III-4 show how such a system might differ from the expected market structure for the NamPower system. Exhibit III-3 represents the expected system structure plus the Kudu Project. Exhibit III-4 shows the restructured NamPower system with the "virtual JV" structure for Kudu or other large IPPs.

EXHIBIT III-3: INTEGRATION OF KUDU POWER INTO NAMPOWER SYSTEM (1)

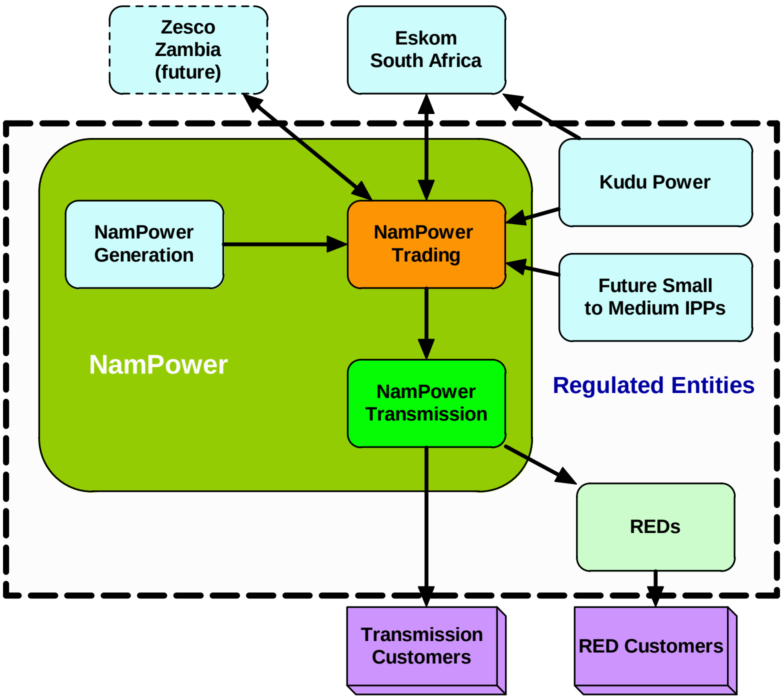
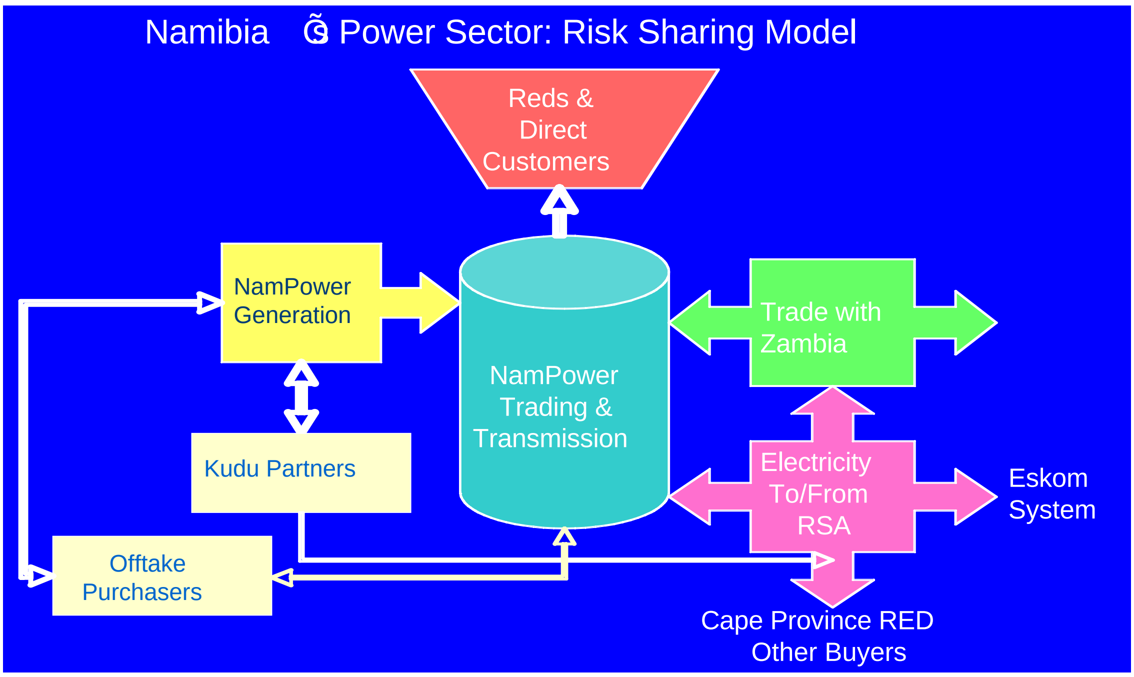


EXHIBIT III-4: INTEGRATION OF KUDU POWER INTO NAMPOWER SYSTEM (2)



A smooth incorporation of the Kudu or some other large project in the current system only partially eases the issues and problems facing other IPPs. In particular, smaller IPPs that wish to sell electricity into the national system must face the following hurdles:

- Lack of a direct connection to NamPower Transmission and trading for small or medium (5-100 MW) IPPs;
- Lack of a readily-available contract structure to sell directly to the REDs, in the case of very small (<2.5 MW) power plants; and
- Lack of an easily customized PPA and pricing formula for smaller power plants.

To more effectively incorporate large IPPs into Namibia's power industry, the thrust of current legislative initiatives is to split the functions of NamPower as shown in Exhibit III-5.

The proposed structure for the power system that can readily accommodate smaller IPPs would establish a modified single-buyer system with both NamPower generation and IPPs (above 5 MW) selling to NamPower Trading and Transmission on a contractual basis. Both entities would have access to the transmission system which would have access through the neutral system operator to both the REDs and other direct customers. This approach relieves the REDs and large users from costly and time-consuming PPA negotiations with small suppliers. Very small IPPs, those below 5 NW, are not shown in the picture, but would connect at the RED level.

The fully worked out new market model would have all of the various entities – generators, traders, transmission, distribution companies, direct customers, foreign generators – with contractual relationships. The core of the market would be governed by ECB-regulated transactions, as is shown in Exhibit III-6.

EXHIBIT III-5: PROPOSED NAMIBIA ELECTRICITY STRUCTURE TO FACILITATE SMALLER IPPs

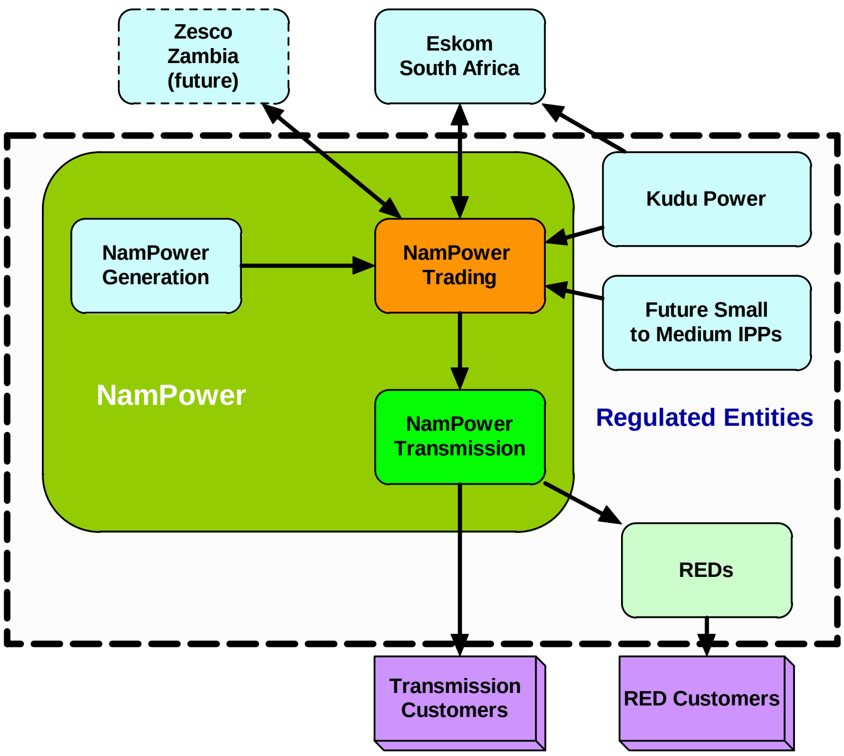
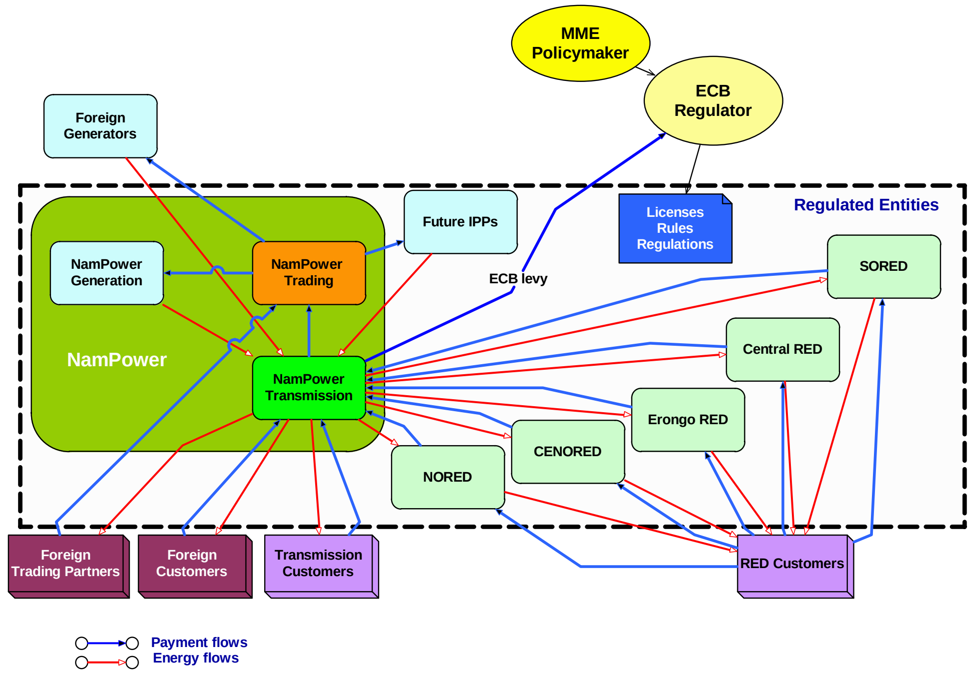


EXHIBIT III-6: POST RESTRUCTURING ELECTRICITY SYSTEM IN NAMIBIA



In the new market model NamPower would be unbundled (de-integrated) into three distinct entities (i) NamPower Generation, which would retain ownership of the three main power stations; (ii) NamPower Trading, the entity that would facilitate buying and selling of electricity between generators and the transmission system; and (iii) NamPower Transmission/system operator, the physical link between generators and customers. Such a structure will assist IPPs in their access to a variety of customers.

However, the barriers to IPPs, highlighted during the Inception Mission and explained in more detail in Annex 6, include a variety of non-structural elements that the Government and ECB will need to address in order to facilitate investment in IPPs, especially competitively procured ones. The barriers to IPPs include tariff issues, institutional and regulatory issues and matters related to the operations and finances of the REDs, and are shown in Exhibit III-7.

Annex 7 and Annex 8 include a discussion of barriers that are specific to different sizes of IPPs, with different fuel cycles.

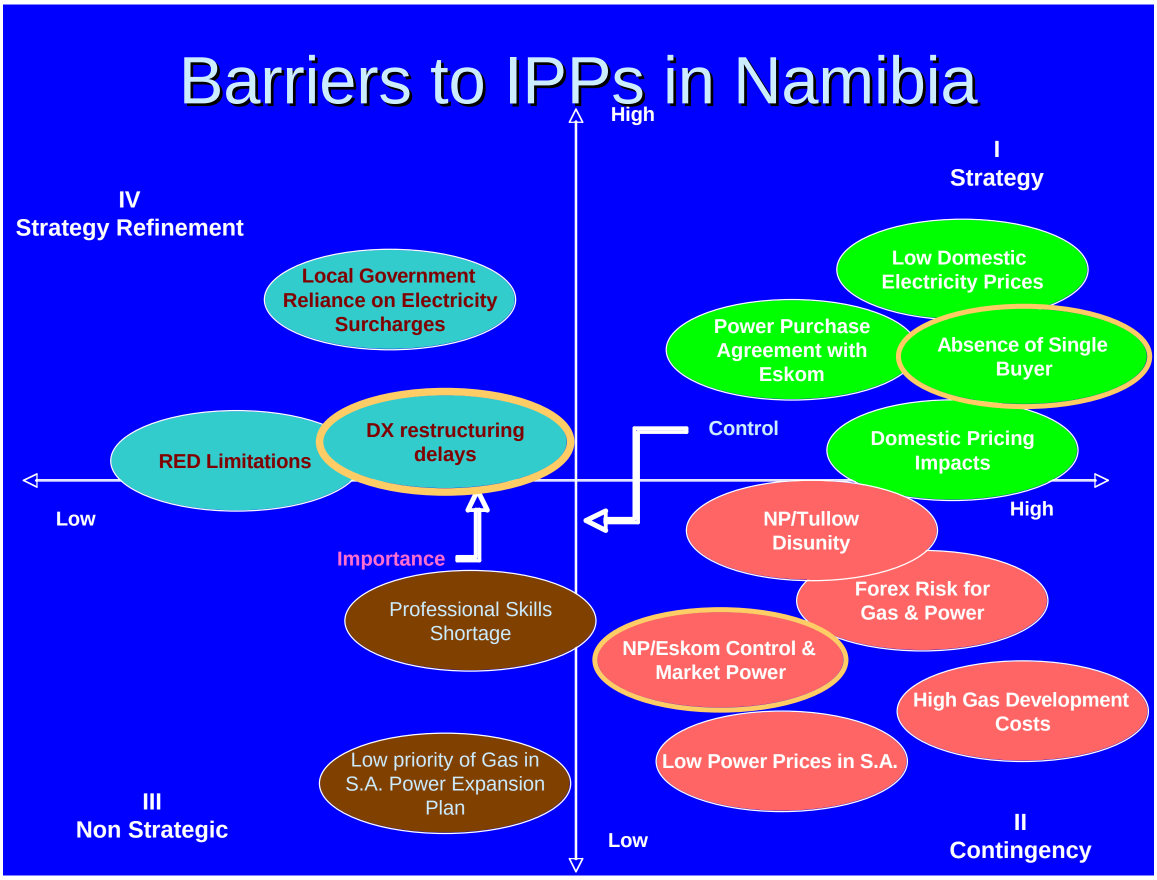
In order to overcome or successfully circumvent these barriers, it will be necessary to promote a series of policies that resolve the most important of these barriers. The next two sections of this report will focus on several specific solutions that should enable Namibia to create (i) a tailored contractual template; along with (ii) a more effective and efficient regulatory and market structure for independent power producers. The essential features of these proposed solutions include the following elements:

- **Contractual format**
    - "One-off" vs. standard format;
    - Open and competitive solicitation v. negotiated tender.

- **Tariff and pricing –**
    - Resolve cost pass-through issues and propose public rules for cost recovery from IPPs;

- Reform current tariff to reflect full "going-forward" cost recovery for all entities to eliminate increased marginal cost impacts of new generators;
- Initiate regulatory review procedures with specific information sharing clauses for power purchase agreements covering "prudence', impacts on consumers, diversity of generation sources and efficiency.

EXHIBIT III-7: TARIFF, REGULATORY, INSTITUTIONAL, AND FINANCIAL BARRIERS TO IPPs IN NAMIBIA



- **Risk allocation –**
  - Investigate risk sharing among large customers for off-take from IPPs to reduce risk to the IPPs for marketing of output;
  - Use NamPower Trading as instrument for aggregation of individual offers to sell power to outside buyers.

- **REDs as IPP customers –**
  - Provide technical and financial guidelines and training to REDs to facilitate their ability to purchase electricity from IPPs
  - Provide standardized PPAs for smaller power plants to reduce transactional costs;
  - Provide technical services to REDs on a contractual basis to allow them to use output from embedded small IPPs effectively.

The next section of this report provides guidelines for different types of IPPs with regulatory, pricing, and structural recommendations keyed to project size, fuel types, and the ECB's continuing responsibility to protect the public interest in IPPs and other areas of the ESI.

B. PROPOSED IPP MODEL

With the extraordinary variety of plant sizes, fuel cycles, locations and methods of connecting to the transmission system, even a relatively small utility such as NamPower will need to make careful distinctions in its approaches to IPPs and their contractual issues. The key distinctions are enumerated at the end of the previous sub-section as contractual matters, tariffs and prices, and access to customers (identity of the counterparty) and transmission of electricity. Recommendations that might work for small projects may not be appropriate for larger ones. There is no "one size fits all" solution for IPPs, nor is there a simple kit that can be used to craft appropriate documents and policies. In assessing the policy, structural and regulatory needs of different types of IPPs the following issues need to be kept in mind and will vary by size, fuel type and technology:

- Competitive solicitations v. negotiated offers;
- Technology – standard (off the shelf) v. custom design; and
- Fuel source – competitively supplied or tied to the project.

These issues are discussed, along with contract form, pricing, and customer access in separate sub-sections for large, medium and small IPPs.

1. LARGE IPP PROJECTS

In Namibia, the opportunities for building large IPPs are relatively limited. Looking at plant sizes above 100 MW, there may be opportunities to build *one* large gas-fired plant (Kudu), one or two coal-fired plants (Walvis Bay), and one or two large hydro stations (upstream of Ruacana). It is not clear at this time whether there exists sufficient wind potential to build a large wind farm.

If each project is the only one of its kind in the country, then it is unlikely to be worthwhile spending the time and resources to develop standard contractual formats for such plants. Experience in other countries has shown that developers of one-off plants of a large size will want to negotiate the project documents from scratch.

Nevertheless, there is a framework for the main project agreements, as well as a regulatory and procurement checklist that is essential for negotiating an appropriate PPA for the project. NamPower and ECB will need to weigh the following key issues in large IPP development:

- How many units will be built?
- How standard is the technology?
- How many vendors can bid on the EPC?
- Is the fuel supply competitive or single sourced?

The responses to these questions will help to determine the conditions under which the solicitation should proceed. In general, the more units to be procured, the more standard the technology and more competitive the fuel supply, the more likely it is that competitive procurement can be used for such plants. It is not likely that these conditions will prevail in Namibia. For each major plant type that might be built over 100 MW, there are one or two units likely to be constructed, fuel supply is particular to the site and technology for the plant will be keyed to the locations and the fuel supply, though probably relatively standard for each plant type.

CORE recommends that large IPPs be negotiated rather than competitively bid in Namibia.

Experience has indicated that with a small number of units there is an increased risk of "low-ball" competitive bids with subsequent problems in implementation. Experiences in East Asia are especially relevant in this instance: competitive solicitations for coal-fired power plants have resulted in acceptance of low bids that were subsequently found to be based on older, dirtier technology and dirty fuels as well. Countries that have used negotiated procurements with tight specifications have had fewer problems with variances in performance and emissions.

If a standard technology is to be used for the large power station, then it should be possible to obtain multiple bids for the EPC contract (at least 3-4 potential bidders). Competition at this stage should be capable of bringing *most* of the benefits of a fully competitive procurement to Namibia with far fewer downside risks.

Fuel supply is another area in which it may be possible to obtain competitive results without a fully competitive power supply situation. If a power plant can be supplied using a relatively generic fuel specification, then it should be possible to obtain multiple bids from potential fuel suppliers, increasing the overall competitively procured content of the plant. Regardless of the conditions of the fuel supply, where there is a negotiated sole source procurement of the plant developers themselves, it will be necessary to integrate the fuel supply agreement (FSA) with the PPA. As has been demonstrated, mostly in a negative sense, around the world, if the FSA gets out of synchronization with the PPA, then one of the parties, or possibly either the consumers or the government, will be called upon to absorb the excess risk arising from the misalignment of risks to the various parties. Annexes 7 (Cross subsidies, tariff design) and 9 (Experiences in other countries) demonstrate the need to retain as complete an alignment of the original allocation of risk as is practicable throughout the life of a PPA. A more complete discussion of FSAs can be found in Section IV of this report, as well as in Annex 12, which is a term sheet for a FSA.

Large IPPs: Role of the Regulator

The role of a regulator is primarily to make sure that the interest of all of the members of the public are represented in decision making on matters that affect regulated entities. This means that the regulator has an opportunity to mitigate some of the risks that may arise in large IPP projects, by ensuring that risks are allocated properly (the prudence review), that risks have been properly accounted for in the pricing methodology (the tariff review) and that the plant is needed and appropriate for the Namibian market (the planning review). Unfortunately, it is also possible for intervention to aggravate risks to the various parties.

A presentation on "Risk Mitigation vs. Risk Aggravation" was made to the ECB during the third mission under this assignment. It is contained in this report in various parts of Annexes 10, 11 and 12. The key points of this approach, as it pertains to large IPPs in Namibia call for mitigation of pricing risk and market risk. The following elements represent recommendations by the CORE Team for mitigation strategies for price and market issues. Regulatory risks are covered in Section III. C of this report.

1. Make sure prices in the PPA are aligned with prices in the domestic market, this means
    - Determine what elements of the tariff can be indexed; and
    - Restructure domestic tariffs to reflect specifically the pass-through provisions of the PPA and FSA.

2. Spread the market risk over new players
    - Large users in Cape Province;
    - Large users in Namibia - mostly mining; and
    - Base load consumers of electricity through the Caprivi Link.

In looking at the alignment of pricing pass -through provisions with the PPA and the FSA, the following key points need to be kept in view at all times. (See Annex 7 for a more complete discussion of pricing pass-through provisions.)

- Determine what can be indexed?
    - Amortization - generally no;
    - Fixed O&M - generally a fraction, subject to negotiation; and
    - Variable O&M - generally all, assuming there is no alternative benchmark for costs;

- Provide a specific schedule of adjustment indices; and
- Make sure that restructuring of domestic tariffs reflects pass-through provisions.

Item 2 has been discussed previously under market models. CORE believes that under appropriate circumstances it may be possible to implement some elements of a multi-market model, especially if this helps to offset market risk. The particular elements of this modified single-buyer approach are:

- Sign PPAs with domestic users (mines and factories) containing additional off-take requirements;
- Each customer, effectively a partner in project, now has incentive to sell excess capacity; and
- Reduce NamPower's share of total project output and project risk.

For each domestic off-taker, a higher price from Kudu or any other large power project is an insurance against the possibility of far higher prices and/or interruptible supplies from Eskom. The second "large project" market model presented earlier in this section shows the suggested relations among and between the parties to lay off market risk for large IPPs. The PPA and FSA, shown in the next section and in Annexes 10-12, are simply reflections of the allocation of risks. They do not create new market forms; rather they reflect decisions that must be made in Namibia concerning how flexible they wish the market model to remain. Under the present plans for the single-buyer market model, NamPower will be the main point of contact for large IPPs, with ECB playing a regulatory and secondary role. Neither REDs nor other customers will exercise any decision-making authority with respect to such projects. Exhibit III-8 sums up the expected information and regulatory flows.

EXHIBIT III-8: INFORMATION AND REGULATORY FLOWS FOR PROJECT AGREEMENTS (LARGE IPPs)

Large IPPs	ECB	NP	RED
Technical & Safety	⭘	◎	○
Sale-Purchase	⭘	◎	○
Tariff	⭘	◎	○
Physical Supply	⭘	◎	○
Delivery & Acceptance of Output	⭘	◎	○
Indemnity	⭘	◎	○
Dispute Resolution	◎	⭘	○
Key: ◎ - Lead; ⭘ - Secondary; ○ - No Role			

The nature of these information flows will be further laid out and detailed in Section IV of this report.

2. MEDIUM IPP PROJECTS

Unlike large IPPs, which almost by definition must be capable of taking a number of different forms, medium IPPs, those in the 5-100 MW range, may be far more standardized and restricted in conception. Also unlike large IPPs, which in Namibia are large enough to affect prices and quantities in the electricity market to a significant degree, medium IPPs are expected to be price takers. However, like large IPPs, medium IPPs will connect to the NamPower transmission system and their output will be sold through the NamPower Trading Company.

Form and Size:
The form of a medium IPP should be reasonably constrained to standardized technologies with competitive fuel supplies or renewable "prime movers". Hydro plants will generally be run-of-the-river in this category, and wind projects will contain 5-50 turbines. It is expected that most of the medium IPPs will make use of renewable sources of energy, except in the case of cogeneration from mining or other industrial projects. The rationale for this bias in favor of renewable projects is simply that larger plants can be expected to convert fuel into electricity at higher efficiencies and lower unit costs than smaller ones. The primary exception to this otherwise unexceptionable observation comes in the realm of cogeneration at industrial or mining facilities, where a steam or heat host can result in significantly higher overall thermal efficiencies for the power plant.

Customers:
A medium IPP will connect with the NamPower transmission system. It is expected that the major customer of the output of this power plant will be NamPower Trading. For intermittent suppliers, especially wind plants, it is unlikely that other entities would be capable of offsetting the variations in output. In some cases it is conceivable that a RED or large industrial user will also be a customer for a Medium IPP, however, this will happen only when the customer has the ability to offset variations in the output of the IPP or the company is co-located with a cogeneration plant. Medium IPPs are not

expected to sell into the export market unless availability and output levels more typical of larger plants can be achieved.

Pricing:
Medium IPPs will need to be price-takers. As a general rule the prices that they receive should be based on wholesale electricity prices (capacity plus energy) prevailing at any given time. The government may choose, as a matter of policy, to give certain preferential prices to renewable generating stations. However, that decision should be outside the NamPower price-setting mechanism and could be established by auctioning the subsidy for the renewable energy source.[20] Time and capacity-sensitive pricing will need to be reserved for plants that are capable of offering capacity to the system. This means that pricing provisions will probably need to be specified by technology according to the prime mover of the particular plant and will have to contain certain provisions outlining the prices to be paid according to (i) plant factor; (ii) plant availability and dispatchability; (iii) contribution to peak output; (iv) ability to contribute to supply of ancillary services; and (v) the ability of the plant operator to mitigate intermittent output (for wind and hydro). For most Medium IPPs, the time variability of pricing will be limited to seasonal and daily variations in the marginal energy component of the wholesale price.

Regulatory Concerns:
Unlike large IPPs where all of the access and technical issues are contained in the project agreements and are negotiated *de novo* for the project, Medium IPP developers should reasonably expect that their transactional costs can be reduced by signing project agreements that have been standardized with respect to the following key provisions:

- Assurance of firm legal rights to resources and sites;
- Competitive solicitation for plant construction;
- Technical and safety regulation provision standardized by technology;
- Pricing of output specified for plant type;
- Succession and transferability clauses provided.

The outline of a PPA for a Medium IPP will be provided in greater detail in Section IV of this report and in Annex 10. Exhibit III-9 shows the information and regulatory flows for a Medium IPP.

For large IPPs most of the information flow and decision-making occurs with NamPower Trading, with the ECB playing a supporting role. For Medium IPPs the ECB will have the lead role in establishing the sales conditions, pricing, and general transactional conditions for the PPA. The ECB will need to enter into an agreement with NamPower so that the utility can provide certain technical services to the Medium IPP projects especially around issues of safety, technical certification and verification and supply/dispatch conditions.

3. SMALL IPP PROJECTS

Small IPP projects, with total peak capacity of less than 5 MW, are expected to be located inside (embedded) in the sub-transmission systems of the REDs. As a general

[20]. The World Bank has used auctions of the differential between the offer price made by the utility and the price that wind generators are willing to accept to push prices for wind generation down in a number of countries. The Bank is currently working in Mexico to implement such a project and the bids have already been evaluated with contracts about to be awarded to the winning bidders – those who bid for the lowest subsidy per kWh from the renewable energy fund.

rule these plants are expected to make use of local resources to generate electricity, meaning little or no use of liquid fuels to generate power.

EXHIBIT III-9: INFORMATION FLOW AND REGULATORY FLOWS FOR PROJECT AGREEMENTS (MEDIUM IPPs)

Medium IPPs	ECB	NP	RED
Technical & Safety	O▯	◉▯	○▯
Sale-Purchase	◉▯	O▯	O▯
Tariff	◉▯	O▯	○▯
Physical Supply	O▯	◉▯	○▯
Delivery & Acceptance of Output	O▯	◉▯	○▯
Indemnity	◉▯	O▯	○▯
Dispute Resolution	◉▯	O▯	○▯
Key: ◉ - Lead; O - Secondary; ○ - No Role ***Note:*** *ECB has primary role in adjudicating indemnity issues. Contracting parties are still liable under PPA.*			

Such plants are expected to contribute to the energy supply in the electricity sector, but generally not to capacity. In some cases, such plants may be able to contribute to ancillary services at the RED level by reducing transmission congestion during peak periods.

Form and Size:
The form of a small IPP should be reasonably constrained to standardized technologies with competitive fuel supplies or renewable “prime movers”. Hydro plants will generally be run-of-the-river in this category, and wind projects will contain 1-5 turbines. Biomass plants will use locally available surplus supplies (e.g., invader bush) as a fuel source. It is expected that virtually all of the small IPPs will make use of renewable sources of energy. The primary exception to this recommendation may come in certain isolated systems, where the use of a hybrid (renewable prime mover plus small diesel engine backup system) is cost effective relative to grid extension.

Customers:
A small IPP will in most cases connect with the RED sub-transmission system. It is expected that the major customer of the output of this power plant will be the RED where the plant is located. For intermittent suppliers, especially wind plants, it is unlikely that other consuming entities would be capable of offsetting the variations in output. In some cases it is conceivable that a small industrial user will also be a customer for a small IPP, however, this will happen only when the customer has the ability to offset variations in the output of the IPP. Connection, dispatch and system stability issues will have to be addressed together with NamPower to ensure that the overall system is not destabilized by small IPPs. A technical framework should be developed jointly by NamPower, the REDs and the ECB that lays down parameters for the placing, sizing and dispatching of small IPPs.

Pricing:
Small IPPs will need to be price-takers. As a general rule the prices that they receive should be based on wholesale electricity prices (energy component only) prevailing at any given time at the RED busbar with NamPower Transmission. Some discount may

need to be factored into this price to account for the cost of incorporating such energy into the RED's system. The government may choose, as a matter of policy, to give certain preferential prices to renewable generating stations. However, that decision should be outside the RED wholesale price-setting mechanism and could be established by auctioning the subsidy for the renewable energy source. It is unlikely that small IPPs can offer time and capacity-sensitive output, so prices will need to be flat over a specified adjustment interval and be based on the displaced energy component only. Unlike large or medium IPPs, small plants will have little or no ability to be dispatched by the system operator; therefore they will be incapable of delivering peak capacity to the RED. Such plants, if they can be reliably operated during peak periods, may provide some ancillary services in the form of reductions in line losses during such periods.

Regulatory Concerns:
Like medium IPPs, small plants will need to have most of the technical and transactional elements of a contract put into standard format so that all of the access and technical issues are contained in the project agreements and are not negotiated *de novo* for the project. Project agreements should reflect standardized terms across the REDs with respect to the following key provisions:

- Assurance of firm legal rights to resources and sites;
- Competitive solicitation for plant construction;
- Technical and safety regulation provision standardized by technology;
- Pricing of output specified for plant type;
- Succession and transferability clauses provided.

The outline of a PPA for a small IPP will be provided with greater detail in Section IV of this report and in Annex 11. Exhibit III-10 shows the information and regulatory flows for a small IPP.

For the procurement of small IPPs, the ECB should take the lead in drawing up the rules for competitive solicitations. As with the Medium IPPs, NamPower should be providing technical services – inspection, safety, certification – on a contract basis to the RED and to the plant developer/owner. NamPower will also need to draw up operational and technical rules for construction and operation.

EXHIBIT III-10: INFORMATION AND REGULATORY FLOWS FOR PROJECT AGREEMENTS (SMALL IPPs)

Small IPPs	ECB	NP	RED
Technical & Safety	⭘	◉	⭘
Sale-Purchase	⭘	○	◉
Tariff	◉	○	⭘
Physical Supply	⭘	○	◉
Delivery & Acceptance of Output	⭘	○	◉
Indemnity	◉	○	⭘
Dispute Resolution	◉	○	⭘
Key: ◉ - Lead; ⭘ - Secondary; ○ - No Role			

C. REGULATORY MODEL

Regulatory Role in Encouraging Private Investment in the Energy Sector
It is an undeniable fact that most governments cannot come even close to funding the tremendous investment needed to expand, rehabilitate and develop the energy sector. The private sector is very much needed to finance the massive investment needed in the energy sectors in most countries. The regulator, if independent, can ensure that the government investment encouragement policies are implemented fairly and in a transparent manner. This provides the investors, both local and foreign, the confidence they need to consider investment. In some countries, the regulators are strong and independent enough to have judicial authority to adjudicate disputes between the government and industry. This also provides external players an added avenue of security and facilitates their decision making process for making large investments in a country. Mitigating real and perceived risks to enable IPPs to enter a market is one of the most important challenges faced by a regulator.

Exhibit III-11 provides a comparative assessment of regulatory framework structures relative to economic growth, electricity coverage, and international risk factors for investments based on a study conducted by Deloitte, Touche, Tomatsu in 11 countries (July 2004). Although it is a small sample and more direct data are needed, it is clear to note that both the economic growth rate and electricity coverage are closely dependent on the regulatory regime and the market structure in the countries. Countries with vertically integrated monopolistic power sectors and a poor regulator with little or no independence generally have lower economic growth and lower electricity coverage rates. This evidence, coupled with empirical and anecdotal data, would confirm that the independence of the regulator from government and market influences needs to be guaranteed if the country hopes to grow its economy and increase the quantity, quality, and reliability of energy service delivery to the consumers.

An effective regulator should be independent from those it regulates, protected from political pressure, and given the full ability to regulate the market by making regulatory policy and enforcement decisions. The regulator should have the authority and jurisdiction to carry out its regulatory and enforcement functions effectively. The other very important mission of an independent regulator in the development of the sector is transparency in decision-making. Transparency means that the process of arriving at regulatory policies and specific rulings is open, consistent and predictable. Transparency in decision-making allows investors, service providers, and the public the opportunity to have knowledge of and participate in the formulation of policies and regulations.

The Case for a Reformed Regulatory Model in Namibia to Promote IPPs in the Power Sector
The subject of the USTDA-funded technical assistance is to support the ECB in developing a framework that would create a climate for the entry of IPPs into the country's electricity market. Decisions with respect to adapting a regulatory model to allow entry of IPPs in the power market in Namibia need to be made carefully, particularly as there are many more failures of IPPs in developing countries and emerging economies than successes. The IPP industry worldwide is filled with many lessons that provide key insights to the design of the optimum regulatory model in Namibia.

EXHIBIT III-11: COMPARATIVE ASSESSMENT OF REGULATORY GOVERNANCE IN SELECTED COUNTRIES – ELECTRICITY ACCESS AND POWER MARKET MODEL

Exhibit I: Regulatory Framework Structure Relative to Economic Growth, Electricity Coverage & International Risk Factors for Investment

Country	Country Risk Rating (Out of 100)	Transparency Rating (Out of 10)	Regulatory Framework	Economic Growth	Electricity Coverage	Power Market Model
Moldova	18.7	2.4	Independent Contracted	6.50%	75%	Wholesale
Peru	21	3.7	Independent Contracted	4.80%	67%	Wholesale
India	47.3	2.8	Independent Contracted	4.30%	60%	Single-Buyer
Argentina	26.2	2.5	Independent	-14.7% in 2002	95%+	Wholesale Competition
Gabon	25.7	NA	Ministry Based	2.90%	40%	Vertically Integrated
Tajikistan	14.3	1.8	Ministry Based	5.00%	10%	Vertically Integrated
Morocco	40.9	3.3	Ministry Based	3.20%	50%	Single
Bangladesh	26.4	1.3	Ministry Based	4.80%	30%	Vertically Integrated
Pakistan	30.7	2.5	Independent Contracted	4.50%	83%	Single-Buyer
Bulgaria	47	3.9	Independent Contracted	4.80%	100%	Single-Buyer
South Africa	40	4.4	Independent	3.00%	80%	Vertically Integrated

Source: Deloitte Touche Tomatsu Emerging Markets, Ltd. (Emerging Markets Group)/USAID: Sustainable Power Sector Reform in Emerging Markets - Financial Issues and Options, July 20, 2004

Pricing issues for IPPs, especially the role of cost pass through, is one of the primary market and regulatory challenges facing the ECB as the IPP business develops in the country. Considerable analysis was done on this issue during the performance of the technical assistance and several specific remedies were identified as mitigating measures. The specific problems identified in the work on regulation included the following:

- Creation of additional risk and uncertainty by ex post cost reviews;
- The unreasonableness of certain IPP costs;
- Lack of knowledge on the part of regulators about how much certain goods and services should cost; and
- A belief that competitive procurement of IPPs will render moot the problems listed above.

Experience around the world with IPPs has indicated that most of the problems created by *ex post* cost and tariff reviews can be either mitigated or eliminated outright by a vigorous *ex ante* tariff review.

The CORE Team recommends that the ECB initiate a program for just such a review process for IPPs.

The unreasonableness of some costs incurred by IPPs and the lack of understanding about such costs by the regulators can be remedied by a regular benchmarking program for major cost elements in the generation of electricity. For smaller systems, such as that in Namibia, some of the cost benchmarks can be obtained from multi-client studies. A key caveat is to distinguish between locally specific costs (e.g., gas from the Kudu field) and internationally standard costs (e.g., dynamos and steam turbo-generators).

Even competitive procurements can result in excess costs, especially if it is assumed that all of the costs in the winning bid are at the lowest possible level and are largely uncontrollable. In most cases neither assumption is true and leads to a full pass-through of costs, many of which are at least somewhat controllable. To mitigate the potentially adverse impacts of "competitive procurement bias," the CORE Team recommends the following:

- Make use of performance benchmarks and incentives in pricing wherever feasible;
- Use competitive tenders only where a standard resource with replicable technology is called for;
- Rely on negotiated transactions for "one of a kind" plants and for first investors in a particular technology.

Annex 8 provides a detailed discussion on the regulatory barriers and risk mitigation for IPPs in Namibia. Specifically, this Annex discusses regulatory issues related to pricing of services, rate design, and the allocation of costs within which IPPs should be addressed in Namibia.

It is recommended that Namibia note the experiences with PPAs in larger markets, especially in the failure to protect consumers, and to prepare contingency plans for the failure of PPAs for large projects. Examples of India and China offer great insight into designing a regulatory model to mitigate risks associated with IPPs. Annex 9 provides interesting insights based on an IPP study by Stanford University. It summarizes results of a study in 10 countries with their experience with IPPs and analyzes the successes and failures in light of various market and regulatory factors. The regulatory and legal analysis focused on individual country studies. Both contractual and project outcomes were analyzed with respect to the country's IPP performance:

- Legal outcomes – did the country enforce critical IPP contracts?
- Project outcomes – did the country exploit private investors or respect the underlying relationship?

The study concluded that PPAs failed in most countries when they were stressed by either macroeconomic issues (Argentina, Indonesia, Malaysia, Philippines), or by events in the electricity sector itself, as in China. In these cases, the allocation of risk to the government was no protection for the investors, though lenders tended to come out somewhat better. The only two cases where the PPAs have not failed, Mexico and Turkey, are instances where there was no stress testing of the PPAs. The study makes a strong case for "stress testing" of all PPAs to assess whether the contractual framework can survive severe changes in the pricing and operational environment.

During the technical assistance, the Team also analyzed the regulatory roles and responsibilities, focusing largely on ECB, in the pricing aspects of IPPs. Annex 7 focuses attention on the role of the regulator in designing a wholesale tariff that can accommodate changes in fuel prices and operating conditions. Annex 8 focuses on a detailed pricing and regulatory barriers analysis. The key issues analyzed are cost pass-throughs and competitive tendering for IPPs.

The CORE Team recommends that ECB take an active role in assessment and approval of cost pass-through provisions for negotiated IPPs. For smaller IPPs, cost pass-through conditions should be included in a standard contract format. Recommendations for the role of competitive vs. negotiated tenders revolved around issues of size, replicability and technological uniqueness. For larger IPPs it is recommended that negotiated tenders be the norm. For smaller, more standardized projects, competitive procedures should be the norm.

A final element of investigation in the regulatory task concerns the interface between the market model and the regulatory framework. One of the most vexing issues in any IPP régime is the question of bias by the incumbent and the consequent disincentives and increases in risk and uncertainty for potential IPP investors. This perception of bias, already addressed in Section II, is critical to mitigate while assuring potential investors that Namibia's market is open and that their investments can be profitable.

As the assessment of the suggested mitigation measures in the table indicates, there is quite a bit that the ECB and the government can do to increase investor confidence and transparency. Also it should be noted that none of these measures relies on the Electricity Bill of 2006 for its legal power.

IV. MODEL DOCUMENTS FOR IPP PROJECTS

This section of the report provides a summary of the key elements of the project agreements for different types of IPPs. Contracts need to be keyed to project types and sizes, with the understanding that provisions that might be appropriate for one type of project may well prove insufficient or inapplicable for another.

As was discussed in the previous section, there are three key elements to a successful implementation of an IPP program: (i) market model; (ii) project agreements; and (iii) appropriate regulatory structure. The discussion of the market model showed that Namibia's single-buyer model will face certain challenges when confronted by the demands of different IPP types. It was suggested that some degree of modification to the single-buyer approach be used to ensure that project risks are appropriately allocated and that the pricing and other provisions reflect the value to Namibia for using electricity from different types of facilities. The regulatory structure, discussed in Section III as well, indicates the need to customize the approach to the demands of the projects and the method of integrating such a project in the country's electric power system.

Briefly discussed in Section III are the project agreements. These are the documents that legally bind the parties to various behaviors and allocate the risks among the parties. The project agreements also provide for the roles of regulators, mediators and government officials in the formulation of prices, the conformance of regulation to various provisions of the project agreements and resolution of disputes. The natures of these agreements parallel the needs of the project developers and the Government of Namibia to allocate risks, provide appropriate incentives and generally establish an environment that is conducive to successful IPP development and responsible project implementation.

Each type of IPP will be treated in its own sub-section of this chapter. For the most part, medium and small IPPs (5-100 MW and <5 MW, respectively) will be able to use relatively standard power purchase agreements (PPAs) while the large projects (>100 MW) will typically require more agreements and custom designed documents.

A. LARGE IPP PROJECTS

Based on the discussion and recommendations in Section III regarding large IPPs, this description of key project documents for large IPPs will take the following factors as given:

- Large IPPs will be negotiated individually and will not be solicited on a full and open competitive basis;
- Just one or two plants of each type (coal, gas, hydro) can be built in Namibia;
- Technology is relatively standardized for hydro and gas, but not for coal;
- Coal can be supplied competitively, while gas is inextricably linked to its final uses;
- A separate fuel supply agreement is essential to ensure that the allocation of fuel price risks remains generally in line with the regulatory guidance for tariffs and cost pass-through provisions.

This section contains summaries of the essential clauses of a fuel supply agreement and a power purchase agreement. Given the small likelihood of repetitive projects of any type for the large size in Namibia, the consultants have recommended in Section III that the PPA and FSA be negotiated from scratch, although a number of generic clauses can be adapted from other agreements. Investors putting more than US $150 million into a project are likely to insist on custom provisions and the time and expense taken by the quest for perfectly malleable project agreement templates can be better spent on drawing up such standardized documents for smaller IPP projects.

Of particular interest in this regard is the fuel supply agreement. A FSA for a smaller project is not really a matter for the public's interest, except insofar as the public wishes to be sure that the fuel was purchased with "prudence," a classic regulatory oversight responsibility. Such projects are generally too small, even in Namibia, to influence the price of electricity. However, large IPPs can and will exert overall influence on market prices for electricity in Namibia. The pricing pass-through provisions for fuel and other costs will directly affect the wholesale price of electricity and power (see Annexes 7 and 8 for a fuller discussion of these matters). Therefore, the CORE team has recommended in Section III that the FSA also be subject to regulatory oversight. This oversight is to ensure that the alignment of pricing risks remains as intended by the PPA and that prices and risks do not get out of alignment with one another.

The remainder of this section will summarize the key provisions of FSAs and PPAs in an annotated exposition to show what types of issues may be of most interest to Namibia in its IPP program.

Key Elements of Fuel and Power Purchase Agreements for Large IPPs

The key elements of a set of legal agreements that permit a project developer to construct and operate a large IPP are the FSA and the PPA. The major elements of these agreements should be negotiated in parallel to ensure that the allocation of risks is appropriate.

The Fuel Supply Agreement (FSA): Key Elements

Exhibit IV-1 lists the key provisions of a FSA for a large power plant project (Please see Annex 12 for a more detailed FSA framework). It discusses generic issues common to most FSAs.

EXHIBIT IV-1: FUEL SUPPLY AGREEMENT (GENERIC CLAUSES)

	Generic Clauses	Notes and Comment
1	Parties	Identifies buyer and seller, notes any other parties (transporters, storage, etc.) that may be named in the agreement
2	Term	Length of contract – usually co-terminus with PPA
3	Termination and Cancellation	Who can terminate contract and under what conditions
4	Conditions Precedent	Financing agreements that must be in place by buyer before agreement can be effective
5	Source of Fuel	Names type of fuel, plant or conversion facility, gas field or other raw source of supply (note: contracts with International Oil Companies will normally contain "Supply from Anywhere" clauses rather than specific refineries, LNG plants, etc.)
6	Substitute Sources	What alternative fuel will supplier provide if fuel named in §5 is unavailable – names a specific alternative
7	Provisions for supply of Substitute Fuel	Financial guarantees and physical arrangements for substitute fuel
8	Shipments	Who transports?

9	Breaches	Consequences of failure to supply – compensation activities and mechanisms
10	Transportation, Scheduling & Facilities	Who owns the ships? Where are the storage facilities? What is frequency of shipment, tolerable variances in delivery schedule?
11	Quality	Specific heat content, flash point, ignition resistance (octane, cetane, etc.), mineral, ash, emissions quality of fuel
12	Exchange Rates	Defined at start and how to adjust later
13	Force Majeure	Conditions that will permit breaches of general provisions – conditions of proof, compensation
14	Commercial Impracticality ("Excuse")	A clause sometimes invoked if a pricing provision is such that the cost of the fuel makes profitable operation of the power plant or profitable sale of the fuel impossible after some period of time. This is essentially a renegotiation clause that contains the parameters within which such renegotiations might take place.
15	Demurrage	Who pays for delays in harbor
16	Insurance	Certification of appropriate insurance
17	Delivery Point	Specific harbor or facility where fuel is to be delivered
18	Inflation Index (US Dollar)	Price adjustment indexed, named and year for basis defined
19	Inflation Index (Local Currency)	Price adjustment indexed, named and year for basis defined

Once the generic clauses have been agreed to, then there must be an agreement on the pricing provisions. The general goal in the pricing area is to satisfy a set of not-altogether-consistent requirements. Namely:

1. Profitable production of the fuel feedstock (natural gas, raw coal);
2. Profitable conversion to power plant fuel (LNG, pipeline gas, cleaned coal, etc.);
3. Cost-effective use of chosen fuel in the power plant;
4. Four different types of possible pricing provisions are presented here.
    a. A direct link to the commodity in question
    b. A direct link to a weighted index of the target fuel as well as other fuels (called the market basket approach)
    c. A mixture of fixed and market prices with escalation & adjustment provisions for the fixed cost components (called the "coal" approach)
    d. A netback methodology that relates prices at both ends of the transaction to market levels (called the "Trinidad" approach)

The market basket approach can have two variants. In one case, the price of fuel, CIF, is simply tied to the local market (including South Africa) prices for other fuels and chemicals by a fixed formula on an energy equivalent basis. In the second case the price of fuel is tied to a basket of factors, one of which is the target fuel itself in some other market (e.g., the use of Henry Hub, Texas, spot prices in Japanese LNG contracts). The netback methodology takes the market price of the fuels and the indices on the basis of some agreed benchmark levels, nets back to the implied gas price and then grosses up the price back to Namibia with agreed-upon conversion and transportation costs.

Exhibit IV-2 discusses the pricing provisions that include a number of schedules in the FSAs.

EXHIBIT IV-2: FUEL SUPPLY AGREEMENTS – DETAILED SCHEDULES

	Pricing Clauses	Notes and Comment
1	Floor Price	Minimum price the commodity can sell for, defined in US Dollar {year} per energy unit
2	Ceiling Price	Maximum price the commodity can sell for, defined in US Dollar {year} per energy unit
3a	CIF Price (Variant 1, single source), or	Bases price of fuel on index consisting of single source (e.g., LNG, Henry Hub Gas, ARA coal ± transport differentials, etc.)
3b	CIF Price (Variant 2, energy commodity basket), or	Bases price of fuel on index consisting of weighted average of substitute or complementary fuels (e.g., xx% naphtha + yy% kerosene + zz % fuel oil + . . . ± transport differentials, etc.)
3c	CIF Price (Variant 3, cost of supply), or	Formula consists of floor price (in US Dollar/GJ), ceiling price, cost at mine-mouth or wellhead ± transport differentials + conversion to desired form (if applicable)
3d	CIF Price (Variant 4, input market {ceiling} and output market {floor} provide price brackets)	Price of fuel consists of floor price (in US Dollar/GJ), reference price, reference price escalation, ceiling price (based on output price of electricity). Prices are adjusted annually from reference path depending on electricity prices and other fuel prices
4	Domestic Price conditions	Price adjustment intervals, adjustment indices, form of price adjustment, permissible bands for adjustment – purpose is to synchronize adjustment with domestic market adjustments and to serve as “sand in the gears” to attenuate amplitude of adjustment in market-based formulae.

The pricing clauses will generally contain detailed pricing formulae (see Annex 12 for additional provisions) and even spreadsheets or the resultant formulae for calculating the prices under a variety of conditions. It is critical to note that domestic pricing considerations for both the fuel and the output (electricity) markets come into explicit consideration in the pricing clauses of a FSA.

The Power Purchase Agreement: Key Elements
Exhibit IV-3: shows the main elements of a Power Purchase Agreement. These provisions are intended to serve as a guide for the types of elements that must be included in the PPA for a large electricity project.

EXHIBIT IV-3: POWER PURCHASE AGREEMENTS – GENERIC CLAUSES

	Generic Provisions	Notes and Comment
1	Definitions	This should be as complete as possible – borrow from other PPAs liberally

2	Sale and purchase of energy and capacity	Identify the seller(s); Specific terms regarding the size of the IPP, net electricity production, identity of the buyer(s); capacity during certain times of day and year, electricity output
3	Term and termination	Duration of PPA, termination conditions, extension conditions, renegotiation of PPA, sale of IPP to third party, definitions of default by either party, notice provisions
4	Control and operation of the power plant, dispatch control	Who is responsible for operation of IPP, how control of dispatch will be accomplished, rights of system operator, declaration of firm plant capacity, scheduling of operations, obligations by seller to notify buyer regarding availability, change in operating levels, emergency operations, record keeping from operations
5	Interconnection	Right to connect to transmission system, data required for interconnection, granting of Rights of Way for transmission, construction of transmission, testing and modification of equipment, guarantees of capacity on system, if appropriate (depends on who pays for transmission capacity reservation)
6	Metering and telecommunications	Specification of types of equipment, who installs primary, who installs secondary, reading of meters and recording data, discrepancies and disputes, repair and replacement of equipment
7	Compensation, payment and billing	Define capacity payments, define energy payments, define responsible parties at Buyer and Seller for preparing invoices and making payments, purchase of energy above Take or Pay level – terms and conditions, forced outages and derating of plant, format for disputes in billing and payments
8	Testing and capacity ratings	Seller's program to test output and operational characteristics of plant, tests of synchronization prior to commercial output, tests after synchronization, additional tests, demonstration of firm capacity rating
9	Insurance	Seller to provide evidence of insurance as per agreement, provision for continued insurance in event of Seller's default
10	Liability and indemnification	Liquidating damages provisions, conditions under which Buyer or Seller may be liable for certain payments, definitions of negligence, accident, etc.
11	Force Majeure	Definition, notification obligations, payments and operations during Force Majeure events, political events and change in local law as Force Majeure events – compensation and payments
12	Taxes	Allocation of tax obligations to Seller and to Buyer
13	Resolution of disputes	Fora for dispute resolution – by parties, by expert, by arbitrator, by court of law - terms and conditions for each forum for resolution
14	Representations, warranties and covenants	Ability of seller to operate power plant, assurance of regular supply of fuel, quality of output (voltage, cycles), system protection equipment obligations by buyer and seller

15	Miscellaneous provisions	Addresses and contacts, amendment procedures, choice of law, survival, rights of lenders, successor and assigns

These provisions must be filled in with the specifics of the project. Much of this language has, by now, become relatively standard, and CORE recommends that ECB and NamPower review publicly available PPAs for large projects to familiarize their legal and business staffs with the more standard provisions.

A separate set of schedules will normally be appended to the main body of the PPA. These schedules will cover specific technical matters relating to the characteristics and operation of the plant, its specifications, equipment, construction issues, technical interconnection matters and the like. There is a separate section that covers pricing. The pricing provisions, identified throughout this technical assistance as the key barriers to successful IPPs, are contained in a separate schedule. This schedule will contain numerous technical provisions, but it must also be compatible with the following domestic market considerations:

- Consistency with domestic market wholesale pricing;
- Consistency with export market wholesale pricing;
- Specific and compatible scheduling of time of day supply prices;
- Use of specified external price or cost references if contract prices are to depend on external markets;
- Escalation clauses must be consistent with both domestic and export market regulations.

The schedules that form the addenda to the PPA are provided in Exhibit IV-4.

EXHIBIT IV-4: POWER PURCHASE AGREEMENTS – DETAILED SCHEDULES

	Schedules	Notes and Comment
1	Functional Specifications	Gross and net generation capacity of individual system components (gas turbines, steam turbines, etc.), ambient atmospheric conditions (to calculate fuel consumption at different temperature and pressure conditions), other important equipment (fuel storage, gas compressors, condensers, etc.)
2	Technical Limits	Synchronization times, fuel consumption during start (by "hot", "warm", "cold"), ramping rates for turbine units, design maintenance limits (hours between major/minor maintenance)
3	Interconnection and Transmission	Design data for interconnection, technical specifications & equipment list, transformers
4	Commissioning and Testing	Certification of firm capacity, certification of output quality, reactive power capacity, response to step load changes
5	Metering Standards and Testing	Calibration of meters
6	Tariff, Indexation and Adjustment	Establishment of reference tariff – capacity purchase price (distinction between escalable and non-escalable components), energy price, supplemental charges and tariffs, pass-through items (identification and formula showing how these items appear in tariff calculation), fuel

		cost adjustment clauses, indexation factors, adjustment methods and intervals, methodology for establishing adjustment factors and examples applied to tariff formula, start-up charges, bonuses and penalties for over/under performance, pro-forma invoice containing full listing of charges and adjustments
7	Construction Reports	Progress reports during construction by type of activity – civil, mechanical, electrical, etc., comparison of planned and actual progress
8	Insurance	Coverage for construction by component, coverage during operations, certification of insurance
9	Company Letter of Credit	Shows specific form of letter of credit to be filed by Seller
10	Project Implementation Schedule	Key dates of project implementation for each component – financial, civil works, mechanical equipment, electrical equipment, start-up

As these tables of generic and specific clauses show, there is a significant volume of work that is required simply to reach a generic agreement. Following that, the detailed work must start on the schedules. CORE recommends that the generic clauses be negotiated from a template and adapted to the conditions of Namibia. The specific schedules will all need to be negotiated de novo and significant numerical testing of the formulae will need to be done to establish that large changes in one or more of the parameters will not result in unacceptable prices or tariffs ("stress testing" the PPA – see Annex 9 for more on this matter).

In light of the importance of the fuel and electricity adjustment clauses to the overall success and acceptability of the project, it is advisable to formulate the wholesale and retail tariffs in tandem with the fuel and tariff schedules of the FSA and PPA. A large project will certainly affect the overall level and structure of tariffs in the country and it is probably unreasonable to expect large investors to agree to an existing tariff adjustment schedule unless that schedule is either (i) generous in its adjustment and pass-through clauses; or (ii) already very high relative to the cost of output from the proposed project.

In order to implement the schedules and to negotiate the clauses appropriately, completely and accurately, CORE recommends that the negotiating parties in Namibia, NamPower and ECB, form a project unit that will merge the detailed financial model of the project with a detailed tariff and fuel calculator.[21] It is only through the exhaustive testing of prices and tariffs in tandem that the parties can state with confidence that prices and tariffs will not get out of synchronization with one another.

B. MEDIUM IPP PROJECTS

The distinction between large and small projects is not only one of size and investment at risk, but also a choice of prime movers. In order to effectively protect the consumers of electricity in terms of both price and reliability, it may be necessary to limit the choices that developers have with regard to the sale of electricity from medium-sized facilities. The discussion and presentation of typical PPA elements that follow are aimed largely at a renewable energy IPP in the 5-100 MW size range and not at a cogeneration plant. A

[21]. ECB's involvement in the project unit comes from its fiduciary and regulatory responsibilities with regard to "prudence" in overseeing investments that can impact tariffs. While the degree of direct involvement may be different for ECB and NamPower, both institutions will have responsibilities that follow the full project cycle.

cogeneration plant that uses fuel to produce electricity, heat and steam will normally use some type of fuel. Such a plant can be expected to furnish firm capacity to the Namibia electricity system and should be subject to the same type of legal documentation as a large power plant. To recapitulate from the Market Model discussion, the key characteristics of Medium IPPs are:

- Size - ~5-100 MW
- Technology - standard
- Resource - competitively supplied
  - Hydro – run-of-the-river with 72-280 hour controllability
  - Cogeneration - from mining or chemicals industries
  - Wind farms with 5-50 turbines

Unlike large IPPs, where the procurement is expected to be "one-off" and technology and fuel conditions may not be standard (at least for Namibia), a Medium IPP will use standardized technology, available from many vendors. It will be the responsibility of NamPower and ECB to specify location, size and off-take purchase conditions – how much electricity, when supplied and where delivered. It will also be the responsibility of the regulator to certify that the proposed power plant has a legal right to the resource in question – i.e., the right to erect wind turbines in a certain area, the right to use a specified volume of water on a particular seasonal schedule, etc. – if it is a common property resource. Issues of water rights, especially with regard to the decisions of foreign governments, should be resolved by the relevant Government Ministry or agency prior to the solicitation.

The competitive procurement of the Medium IPP will place additional responsibilities on NamPower and the ECB. In addition to the technical specifications for the plant, these entities will need to design a solicitation and bid evaluation procedure that is efficient, fair and transparent. There will need to be procedures for appeal and comment about the awards.

While the market model discussion delineates size ranges for different IPP integration approaches, these MW limits should not be taken as absolute. Rather, they should be taken as a distinction between power plants that can affect the cost of service and the operational characteristics of the country's electric power system in a significant way (large IPPs), and those that are connected to the transmission network but are essentially price takers (Medium IPPs). No allowance is made for multiple off-takers from the facility. The PPA outline below contemplates simply one off-taker, NamPower Trading. If the country decides to move toward a modified single-buyer system with multiple off-takers, as was discussed in Section III, then the PPA model will need to be modified so that either (i) there is a separate PPA for each off-taker; or (ii) each off-taker signs the NamPower PPA. There would then need to be separate agreements between NamPower and the other off-takers covering specific matters of energy off-take volumes, renewable energy credit allocation, and the like.

The illustrative example used in this report for a Medium IPP power purchase agreement is a wind farm. This example, while providing most of the major clauses and schedules of a PPA, also illustrates the special concerns that must be kept in mind when negotiating a PPA for a price-taking, intermittent output facility. In particular, there are issues of payments for capacity, if any, and backup power that are absent from the large IPP agreements. At the same time, there is little need for detailed synchronization of the PPA with the wholesale and retail tariff schedules since the plant is a price taker. The issue of special "green" payments for renewable IPPs is discussed in Exhibit IV-5. The detailed text of the PPA is presented in Annex 10.

EXHIBIT IV-5: WIND PROJECT PPA PROVISIONS – ARTICLES AND SCHEDULES

	Article	Notes and Comment	Key Differences From Large Project PPA
1	Definitions	This should be as complete as possible – borrow from other PPAs liberally	Some definitions on wind and renewable energy credits may be added
2	Sale and purchase of energy and capacity	Identify the seller (s); Specific terms regarding the size of the IPP, net electricity production, identity of the buyer(s); capacity during certain times of day and year, electricity output	Contract will specify that payment is for energy only; capacity payments, if any, will be subject to specific schedule; renewable energy credits, if any, will be subject to specific schedule and will be included in price of electricity with benefits from Government assigned to Buyer; energy payment rate will be specified as starting value in contract and will generally contain a ceiling price as well; time of day pricing to be used only if output is controllable by time of day[22]; contract must specify rights to purchase and prices for "excess energy" – electricity produced above statistical expectation based on wind resource data; clause will also detail payments to be made if Buyer does not accept contracted output from plant. Will need a clause on Seller's failure to deliver energy and consequences thereof.
3	Term and termination	Duration of PPA, termination conditions, extension conditions, renegotiation of PPA, sale of IPP to third party, definitions of default by either party, notice provisions	Key variation in this article concerns renewable energy credits and responsibility for failure to obtain them from Government. Since largest share of credit will normally go to Purchaser, the Purchaser is normally responsible for arranging for such credits to be included in project. In Namibia, this means that NamPower will be primarily responsible for appropriate acquisition of wind credits, if any.
4	Control and operation of the	Who is responsible for operation of IPP, how	Seller will be responsible for operation of plant; dispatch is to be

[22]. *Controllable generally means at the discretion of the Buyer. In the present context, controllability will generally refer to cogeneration plants with variable power and steam output and run-of-the-river hydro plants with 72-280 hour storage capabilities.*

	power plant, dispatch control	control of dispatch will be accomplished, rights of system operator, declaration of firm plant capacity, scheduling of operations, obligations by seller to notify buyer regarding availability, change in operating levels, emergency operations, record keeping from operations	done by Seller with appropriate notifications and technical safeguards for Buyer. There is no declaration of firm plant capacity since power is not sold as part of PPA.
5	Interconnection	Right to connect to transmission system, data required for interconnection, granting of Rights of Way for transmission, construction of transmission, testing and modification of equipment, guarantees of capacity on system, if appropriate (depends on who pays for transmission capacity reservation)	No change to technical specifications. However, Buyer may have to purchase transmission credits if seller has invested in system upgrades for project and Buyer uses this capacity when wind facility is not operating.
6	Metering and telecommunications	Specification of types of equipment, who installs primary, who installs secondary, reading of meters and recording data, discrepancies and disputes, repair and replacement of equipment.	Wind projects will typically include detailed wind measurement equipment as well as electricity metering equipment.
7	Compensation, payment and billing	Define capacity payments, define energy payments, define responsible parties at Buyer and Seller for preparing invoices and making payments, purchase of energy above Take or Pay level – terms and conditions, forced outages and derating of plant, format for disputes in billing and payments, etc.	No Change, but capacity component not important in billing calculation.

8	Testing and capacity ratings	Seller's program to test output and operational characteristics of plant, tests of synchronization prior to commercial output, tests after synchronization, additional tests, demonstration of firm capacity rating	Testing program will determine whether and to what extent output from the facility is predictable using wind data gathered from measurement equipment.
9	Insurance	Seller to provide evidence of insurance as per agreement, provision for continued insurance in event of Seller's default	Higher likelihood of complete loss of plant due to adverse weather event requires additional insurance coverage.
10	Liability and indemnification	Liquidating damages provisions, conditions under which Buyer or Seller may be liable for certain payments, definitions of negligence, accident, etc.	Generally less stringent than for fossil plants. Greater obligations on parts of both Seller and Buyer to make sure that the transients in system do not damage equipment on either side.
11	Force Majeure	Definition, notification obligations, payments and operations during Force Majeure events, political events and change in local law as Force Majeure events – compensation and payments	Generally more lenient than for large fossil plant.
12	Taxes	Allocation of tax obligations to Seller and to Buyer	Must include consideration of calculation and allocation of renewable energy credits and other renewable energy-specific subsidies or credits. This article will generally refer to a schedule at the back of the agreement.
13	Resolution of disputes	Fora for dispute resolution – by parties, by expert, by arbitrator - terms and conditions for each forum for resolution	Less recourse to courts than for large fossil plants. Emphasis on expert resolution rather than arbitration or court remedies
14	Representations, warranties and covenants	Ability of seller to operate power plant, assurance of regular supply of fuel, quality of output (voltage, cycles), system protection equipment obligations by buyer and seller	No Change

15	Miscellaneous provisions	Addresses and contacts, amendment procedures, choice of law, survival, rights of lenders, successor and assigns	No Change

Additional schedules are expected to cover important elements of the contract that are too detailed for the generic sections. These schedules will cover the contract price for power, the allocation of renewable energy production or tax credits, and the detailed technical specifications of the plant, as with a large fossil facility.

Payments of Capacity for Renewable Energy Facilities: A Summary of the Issues and Problems

The issue of capacity payments for renewable energy IPPs continues to be a controversial one. For run of river (ROR) hydro there seems to be an agreed-upon technical solution, but such a resolution has thus far eluded wind generation plants.

Firm capacity is generally considered to be the ability to generate on demand from the system operator a specific capacity figure with more than 90% probability. For ROR plants this figure can often be achieved through the use of short term storage (72-280 hours), which allows the system operator to control production through the course of a day – storing water at night rather than spilling – in order to save water for the peak hours. While the output from such a plant is not as reliable as an inter-annual storage plant, the contribution to peak output is undeniable and the capacity credits are earned by the facility.

For wind farms the situation is far less clear. The wind can be analyzed such that there is a statistical expectation of the 90% availability figure for a particular wind farm. However, the plant output cannot be controlled with the precision of dispatch of fossil or hydro units. In Northwest Europe the configuration of the electricity generating systems, aside from the hydro-dominated NordPool system, does not permit the cycling of plants necessary to accommodate the large hourly variations in wind output. As a result, the very large (>40 GW) investment in wind generation has a relatively small impact on capacity needs.

Recent investigations by the World Bank, General Electric and the PJM transmission system have shown that there exist several technical options that will allow greater value to be extracted from wind, in some cases permitting the payment for partial capacity contribution.

There are two main approaches that are applicable to Namibia for determining whether and to what extent wind can contribute to capacity. The first is to simply use historical data and turbine technical data to calculate the expected availability of the wind turbines as a percentage of total installed capacity during peak periods. The fraction that is available more than 90% of the time is then considered to be the firm capacity of the wind facility. PJM uses this approach and has published its payment schedule in the public tariff.[23]

A second alternative is to co-operate wind and storage hydro facilities so as to bid a specified volume of firm capacity during peak hours. In this formulation the hydro plant is responsible for backing up the wind generator, but is not needed when the wind generator is producing at above expected volumes. Such a scheme is being developed for Mexico by the World Bank and requires close coordination of system operation and plant operation. General Electric has

[23]. *That figure is now 20% of nameplate capacity.*

found that they need to track and control for one second variations in wind generation to maintain adequate system stability.[24]

A third approach, used in larger, market-oriented systems, involves the use of day-ahead bids for the expected generation from wind. This method is based on advanced weather simulations and forecasts and is now used in several power pools in the USA. Such an approach could be applied in Namibia if (i) South Africa were to open the Johannesburg Power Exchange for a full array of trading products; (ii) NamPower were fully integrated with Zambian hydro generation in real time; and (iii) wind generators in Namibia were geographically dispersed so as to partially reduce the specific temporal variations in output.

The final subsection contains a discussion on the characteristics of small power plants and the contractual issues that are unique to such facilities.

C. SMALL IPP PROJECTS

Much of the discussion related to Medium IPPs applies to Small IPPs with the following key differences:

- Size - less than 5 MW
- Technology – standard technology commercially available around the world
- Resource - competitively supplied
    - Hydro - run of river
    - Wind farms with small turbines 5-50 turbines
    - Other renewable energy resources

In the case of the Small IPPs, the only customer for the power will be REDs and there will be no capacity payments to them as they will be supplying energy only. Typically, the buyer, in this case the REDs will require the IPP to pay connection charges and these are typically deducted from payments from the energy purchased by the RED.

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[24]. Using elements of the GE Power Systems modeling suite, showed how technical analysis from a powerflow model could be integrated with statistical measures of risk, transmission system performance and bidding behavior to give a basis for estimating the reliability of supply with and without the wind resources in New York State. (See Doug Welsh, "The Effects of Integrating Wind Power on the New York State Power System" in D. Hertzmark, ESMAP, Power Investment Modeling and Risk Mitigation, World Bank, forthcoming)

Very detailed wind studies, with resolutions down to one second in some cases, were combined with NY ISO hourly load data and day-ahead forecasts. These measurement efforts were analyzed to determine the variance in system performance with regard to meeting load with and without wind generation.

Using day-ahead wind forecasting, it was possible to reduce substantially the use of fuel to meet peak demand for power when wind was available. As has been shown by a firm that specializes in advanced weather simulation for renewable energy generators, 3Tier (see 3Tier Group, "Risk Assessment in Renewable Energy Projects" in Hertzmark, op cit), the ability to predict wind even one day in advance at a fairly rudimentary level of precision can result in significant savings over the no prediction case. Both papers will be published in October 2006 by the World Bank in the Esmap Report, D. Hertzmark ed.

The GE researchers found that it was necessary to combine production simulation, transmission system performance and wind data to effectively understand the behavior of the system with additional wind generation. In addition, they found that load varies more than does wind availability from one day to another, minimizing the stability impacts of wind on the overall system. However, the authors suggested that seasonal wind characteristics needed to be assessed as a part of an optimal generation portfolio so as not to induce the underbuilding of other system resources, with a consequent degradation in reliability.

Much of the discussions for Medium IPPs can apply to small IPPs and following typical model documents need to be developed to promote renewable energy based Small IPP projects:

- No fuel supply agreement (FSA) will be needed if the IPP is based on renewable energy sources such as wind
- A license will need to be awarded to the Small IPP developer and typically the PPA is included in the license
- Since the CORE Team feels that the Small IPPs should be embedded in the REDs, contractual documents will be required between the RED and the IPP developer. These documents will include all terms and conditions for supply of power as well as technical performance standards and the usual clauses for default and compliance including penalties and dispute settlement.

The most practiced model for promoting Small IPPs is through a competitive tender that prescribes all the terms and conditions and the license to be awarded by ECB will explicitly incorporate all the elements that commonly go into a PPA.

A successful example of a Small IPP program is the development of the mini and micro hydropower industry in Sri Lanka over the last 6 years. The Government designed a Small Power Purchase Agreement (SPPA) in response to considerable pressure from the private sector interested in developing a small hydropower industry throughout the country. During the last 6 years, a total of are 36 small hydropower IPPs with a total capacity of 85 MW are operational throughout the country. The overall plant factor is 45% and these developers are offering cheap electricity to the Sri Lankan consumers. This sector represents an overall investment of around $100 million, all from the private sector - an impressive record in a developing country. The growth of this sector has surpassed the expectations of the energy planners in the country. Current trends indicate that the contribution of mini-hydropower to the country's energy sector could reach approximately 200-300 MW by 2010, as the sector is growing very rapidly. Three key factors have directly contributed to this growth:

- The SPPA implemented by the Ceylon Electricity Board provides a clear framework and pricing structure which encourages private investors;
- The financing available from the Energy Service Delivery (ESD) Project jointly financed by the Global Environment Facility (GEF) and the World Bank was very attractive. The second stage of the ESD Project is continuing under a new name – Renewable Energy for Rural Economic Development (RERED) Project, clearing the way for additional investments in the sector;
- The incentives offered by the Board of Investment (BOI) in Sri Lanka are attractive

In May 2006, the Government of Sri Lanka revised its energy policy. The new energy policy promulgated by the Government sets a target of 10 percent share from renewable energy in the country's generation mix by 2010. This opens up an additional market of approximately 200 – 300 MW. Given the impressive success with small hydropower IPPs, the Government has recently signed Letters of Intent (LOIs) with four commercial developers for the purpose of developing 34MW of wind power plants in the West Coast of the country. The Government is using a modified SPPA for these wind power IPPs. The Government plans to commission these projects by mid 2008.[25]

Annex 11 provides a model PPA for Small IPPs that could be customized and integrated into a model license for Small IPPs in Namibia. This model PPA include all key elements that are typically included in renewable energy based project licenses to private developers. The competitive procurement of the Small IPPs will place additional responsibilities on NamPower and the ECB. In addition to the technical specifications for the Small IPPs, these entities will need to design a standard tender document, and a standard license and tender evaluation and license award process that is fair and transparent. In addition, there will need to be procedures for appeal and comment about the license awards.

CORE recommends that ECB consider proceeding forward with a small IPP program and develop the necessary regulatory infrastructure and instruments to begin the licensing process.

[25]. Applications from IPP developers that are received prior to the establishment of a fully-implemented approval and contracting system will be treated using provisional procedures that will be similar to the final project approval processes and procedures.

V. DEVELOPMENT IMPACTS OF NEW IPP PROJECTS

A. KEY COMPONENTS OF ASSESSING DEVELOPMENT IMPACTS

All USTDA funded grants for technical assistance and feasibility studies require that the Grantee ensure that the selected Consultant conduct a development impact assessment of the grant in accordance with a detailed guideline prepared by USTDA. The following are specific activities that are required under the Grant Agreement signed between the USTDA and ECB:

- Follow USTDA Development Impact Assessment Criteria
- Assess impacts on: human capacity building, institutional capacity building, market reforms, and productivity
- Assess impacts on macro issues, including: overall sector efficiency, technology transfer, national income, employment, income distribution, labor skills, etc.
- Assess social and micro impacts such as population dislocations, land-use issues, environmental effects, etc.

The current project is a Technical Assistance Grant to the ECB to develop an IPP market framework and provide model documents in order to (i) encourage the entry of IPPs into Namibia's power market and (ii) prepared the ECB to discharge its regulatory responsibilities in accordance with the Namibian Law and the Government's energy policies. In this sense it is different from a typical grant by USTDA for the engineering and financial feasibility of a high priority infrastructure project such a new power plant, modernization of a refinery, or rehabilitation and expansion of an airport.

USTDA routinely requires that all Grantees receiving USTDA grants require the Consultant selected to perform the Terms of Reference under the Grant to conduct a development impact assessment of the project in accordance with USTDA guidelines. While this would be a straight forward task for a defined project, estimating such impacts for a technical assistance such as the grant to ECB must utilize a process that would measure both qualitative impacts of the technical assistance and quantitative impacts if the technical assistance leads to actual implementation of any infrastructure projects.

The proposed technical assistance to ECB is devoted to preparing the ECB to exercise its regulatory role in a reforming power market in Namibia. In keeping with Vision 2030, it is clear that Namibia will need to add significant new power capacity, much of which has to come from IPPs. Accordingly, the development impact of the technical assistance needs to be measured at two levels as follows:

1. Direct Impact on the Capacity and Human Resources of ECB – These include impacts such as increased skill levels, improved regulatory governance, improved environment for private participation in Namibia's power sector, improved transparency and accountability in the power sector, greater investor confidence, increase in customer satisfaction in terms of quality of service, and related tangible governance improvements creating a better climate for large private sector investments in the country's power sector.

2. Downstream Impacts of any IPP Investments – These will include impacts such as additional employment, contribution to the country's GNP, and increased business investment. Increase in urban and peri-urban development and

infrastructure investments leading to further new jobs, enhanced energy security and quality of life, benefits to consumer resulting from market competition and improved sector efficiency, and other direct and indirect economic benefits.

The methodology used by most analysts and the development finance institutions such as the World Bank, African Development Bank (AfDB), Asian Development Bank (ADB), and the European Union (EU), albeit different in the levels of detail, are similar in terms of the approach used to classify the various types of development impacts. In the energy sector, a large number of stakeholders are involved and therefore, the methodology for assessing development impacts should take into account all stakeholder groups that will be affected, directly or indirectly, by the improved environment for IPPs, and then examine what the impact on that group will be beyond what can readily be captured in project financial feasibility study's financial rate of return (FRR) analysis. Impacts are typically described as costs or benefits. Where quantification is impossible, as in assessing the value to others from the current USTDA technical assistance to ECB, qualitative judgments of value based on other similar initiatives elsewhere need to be made.

Developmental impacts of the current technical assistance to Namibia on key stakeholders in addition to the ECB as an institution will be as follows:

Financiers:
A part of the current TA has addressed the barriers on the banking system and its ability to participate in financing upcoming IPPs in Namibia. As a result of the TA, specific recommendations have been made that will significantly improve the market rules and regulatory oversight. This will provide the financial institutions a level of comfort that is expected to induce new investments in the power sector in the country.

Employees of Enterprises:
Net benefits of more power plant construction and operation likely to result from the entry of IPPs in Namibia's power sector will include increased wages received by employees as compared to alternative employment as well as health, pensions, special housing or access to special schools or similar fringe benefits. Other benefits to employees include training received as a consequence of employment in an IPP project company. Additional benefits will come from improved sector performance resulting from manger training as well as training in the use of new technology and new business methods by the power sector workforce.

Customers:
As ECB moves forward with many of the recommendations resulting from this TA, significant benefits to consumers from increased access to power are anticipated. Both the consumers that previously did not have access to electricity as well as those with improved services and more reliable supply of power will benefit in terms of both improved quality of life and enhanced economic activity.

The benefit to new consumers is how much they would be willing to pay for the electricity, that is, the area under the market demand curve. What they in fact pay is the market price, but this portion of the benefits is already counted as the revenues accruing to the project financiers from electricity sales. Better quality power to existing customers will bring additional benefit, if sold at the same price that is not included in the financial rate of return. Since the Project will add to the supply of the electricity in the market, the price of electricity may be reduced for additional benefit.

Producers of Complementary Products:
A complementary good is one whose value to the consumer increases when the supply of the good it is complementary to increases. Power sector improvements typically trigger significant increases in agricultural, commercial and industrial production. These are discussed below. Two diverse prime examples of complementary products are mining equipment and mobile telephony. Cell phone use is skyrocketing in Africa and electric power is needed critically to recharge batteries, operate microwave transmission towers and for other purposes. Crushing and heating rock for extraction of ores or stones requires a great deal of electricity. The more of such energy that can be supplied at a reasonable price, the greater will be the growth of that sector of the Namibian economy.

Suppliers:
Maintenance and operation of the power plant will increase demand for suppliers of these goods and services and hence produce higher profits. Similarly, the increase in wages (beyond what they would have been receiving elsewhere) of the additional workers employed by the suppliers will also be a direct development benefit of additional new power plants in the country.

The creation of new supplier networks can be extremely important to the development of Namibia. Quantifying their value to society will probably be too difficult, but at a minimum the value would include the extra profits they are now earning plus the extra wages of additional workers employed.

Competitors and New Entrants:
Some existing competitors—for example, the suppliers of back up diesel generator sets, suppliers of on-site power for mining operations—may see a reduced demand for their products. Positive impacts on competitors also exist and these might include demonstration effects. The project may demonstrate to others:

- The viability of some new technology, such as energy-saving or efficiency enhancing power equipment
- The viability of reorganizing a business that is inherent to this change in the power system structure
- The viability of some market that previously had been of uncertain size or strength
- Corporate best practice
- The availability of finance, perhaps in the innovative way IPPs will be financed.
- Positive effects of supplier or other networks.

New entrants may be drawn into the power market because of the value of these demonstration effects and network effects. In contrast to old competitors, there can be no doubt that new entrants benefit as they were not in the market at all before. Arriving at a quantifiable social value for this is not possible in the absence of a concrete project.

Neighbors:
"Neighbors" is used here as a loose term for all those who may be affected by an IPP Project, but who do not have a direct market relationship with the Project, i.e., they are not investors, employers, employees, customers, suppliers, or competitors. Impacts on neighbors that will be considered include environmental externalities, new infrastructure made possible by the availability of reliable electric power, and the development of social infrastructure. The construction of new IPP plants will impact the further development of the social infrastructure of the community: theaters, restaurants, community centers, and

so on, some of which might not have been viable before an IPP investment came into operation.

An excellent paper on the subject is a Discussion Draft Paper: Independent Power Production – Benefits to Local Communities, prepared by R. Guy Heywood, Renaissance Power Corporation. This paper discusses the case of British Columbia Hydro and focuses on small IPPs. For a 7 MW IPP project, for example, the development impacts are quantified as follows:

• Total Capital Cost	CAN $15 Million
• Employment Person Years	90 per year averaged over the construction and operation period
• GDP Contribution	CAN $5,750 per year
• Provincial and Local Tax Revenues	CAN $1,176 per year

The Draft Discussion Paper goes on to indicate that the small IPP industry can lead to many positive social and community development impacts in small communities throughout British Columbia.

The next section takes this discussion a bit further in terms of the types of development impacts that can be expected by Namibia as new IPPs enter the power market in the country.

B. EXPECTED DEVELOPMENT IMPACTS

There is no question that sooner rather than later, IPPs will enter the power market in Namibia. Electricity demand and Gross National Product (GNP) have a strong correlation; the more developed the economy greater the level of correlation. Similarly, the relationship between increase in energy use and corresponding increase in productivity offers a good measure of the economic benefits of increased availability of reliable and affordable energy. To foster increased productivity and development in Namibia, policy should stimulate increased efficiency of electricity use.

At a gross level, Namibia can expect the following types of direct impacts from the entry of IPPs in the country's power sector:

Impact of Independent Power Production of 1MW

1. Primary Employment	4 Employees
2. Secondary Employment	8 Employees
3. Temporary Employment	10 Employees
4. LT Line Construction	5 Kilometers
5. GNP Added (Direct from IPP)	$10,000 Per Year
6. GNP Added (Indirect from Other Activities)	$50,000 per Year

Note: These figures are indicative only and will vary widely depending upon individual country characteristics, technology, market factors, etc.

At a minimum, USTDA requires the development impacts to be characterized within the following broad categories of impacts:

- Infrastructure Related Impacts
- Market-Oriented Reform
- Human Capacity Building
- Technology Transfer and Productivity Enhancement
- Other Development Impacts.

Exhibit V-1 categorizes the expected development impacts from future IPP constructions in Namibia that are expected as a result of overall sector reform and the establishment of an enabling environment for private power investment, the focus of the USTDA technical assistance to the ECB.

EXHIBIT V-1: POTENTIAL DEVELOPMENT IMPACTS OF THE IPP AND INVESTMENT MARKET FRAMEWORK TECHNICAL ASSISTANCE TO THE ELECTRICITY CONTROL BOARD OF NAMIBIA

USTDA GRANT ACTIVITY		TYPE OF IMPACT	DESCRIPTION OF THE IMPACT
1.	**Namibia IPP and Investment Market Framework Technical Assistance**	**Infrastructure Related Impact**	The support provided under this Technical Assistance will result in energy sector reform and improved regulatory governance. A direct result of the grant will be to create an enabling environment for encouraging the entry of private investors into Namibia's power sector. As IPPs enter the Namibian market, there will be considerable impact on the infrastructure of the country. The direct and indirect infrastructure impacts will include the following: • Construction of power plants, additional transmission lines, distribution lines, substations, and electricity delivery networks to endues customers • Additional construction of roads, housing, communities service entities, and industrial facilities • Regional infrastructure developments related to regional interconnections needed for power exchange and trading in the Region • Other site-specific infrastructure impacts such as water supply systems, institutional buildings, etc.
		Market-Oriented Reform	This TA will cause significant market-oriented impact on the power market both within Namibia and in the Southern Africa Region in terms of power trading. Currently, Namibia seems to be operating on the basis of a single buyer (SB) model. As more and more IPPs are constructed, Namibia may move to a multiple seller multiple buyer (MSMB) model. This will create market competition in generation and will lead to efficiency gains and cost reduction. In a competitive market, the consumer will be the ultimate beneficiary as the quality of service and supply will improve whereas the cost of service and thus the tariffs will go down. As a result of transparent market rules to be promulgated by the ECB, Namibia will also strengthen its position in the regional electricity market and will be a

USTDA GRANT ACTIVITY		TYPE OF IMPACT	DESCRIPTION OF THE IMPACT
			stronger and effective player. Enhanced security of power supply will lead to overall energy security of the country; reduce its vulnerability to interruptible sources of supply; and lead to a more robust economic growth and a generally more peaceful society. Finally, increased diversity of prime movers in the power market will reduce Namibia's exposure to external pricing risks.
		Human Capacity Building	This TA included a number of workshops for not only ECB officials but also other energy sector stakeholders. Officials from NamPower, the Ministry of Mines and Energy, consumer associations, Regional Electricity distributors (REDs), industry associations, the NGO community, and other ministries in the Government participated in the various workshops on (i) Market Models, (ii) Regulatory Models, (iii) IPP Barriers and Mitigation Measures, (iv) Cost Allocation, Cross Subsidies, and Rate Design, and (v) various working sessions throughout the performance of the TA. These workshops served as mini on-the-job training sessions and the human capacity building effect is clearly evident in the sense that ECB, the enterprises, and the Government are moving forward with the specific recommendations of the TA. The officials from these entities have greater knowledge and enhanced skills in designing processes and procedures that will significantly strengthen the governance of the sector. Specific areas of human capacity building include the following: • Energy sector policy reform • Rational energy pricing and world class PPAs and tendering procedures • Fair and transparent regulatory regime • Improved licensing procedures and contracts • Improved customer relations management by utilities • Fair market and trading rules • Improved overall sector planning and linage with national economic development planning.

USTDA GRANT ACTIVITY		TYPE OF IMPACT	DESCRIPTION OF THE IMPACT
			As new IPPs are constructed, the developers will employ and train hundreds of new individuals to run the business of power generation. This will also add more new personnel in the transmission and distribution sector of the power business. Therefore, the human capacity building impacts will increase several fold.
		Technology Transfer and Productivity Enhancement	There will be considerable technology transfer impacts as a result of the implementation of modern electric power technology and systems that will be brought into Namibia by the IPPs. The introduction of new power generation technology will lead to overall power sector productivity enhancement as well. Specifically, technologies such as IGCC, Combined Cycle Gas, Cogeneration, wind power, etc., will not only diversify the generation mix but also result in substantial technology transfer and productivity enhancement.
		Other Development Impacts	Availability of reliable electricity will lead to considerable satellite industry and secondary development in the country. Also, availability of electricity to rural communities will lead to greater rural development and poverty alleviation.

VI. REGULATORY CAPACITY BUILDING REQUIREMENTS

A. INSTITUTIONAL ISSUES AND REGULATORY GOVERNANCE

Sustainable Development and Good Governance
Sustainable development encompasses economic, social, and ecological components and can be achieved only when these three components form the basis for an integrated approach to development. Economic sustainability requires that development is economically efficient and that resources are allocated and managed efficiently to support future generations. Social sustainability can be achieved through a development process that increases people's choices and control over their lives through democracy and good governance. Ecological sustainability ensures that development is compatible with the maintenance of essential ecological processes.

While good governance is critical to development in any sector, no where is it more needed than in the energy sector. Essentially, in the case of energy sector good governance involves at least three parallel components – (i) Policy Reform, (ii) Regulatory Strengthening and Reform, and (iii) Energy Enterprise Commercialization and Consumer Orientation. Tying all these three components together should be a bottom-up approach where the consumer or the citizenry is very much in charge.

The Energy Sector Challenge
This decade's main energy sector priorities that many developing countries and emerging economies face are as follows:

- Reforming energy sector governance by replacing traditional models resulting in poor energy service by best practices that have proved successful in providing clean, reliable, and affordable energy to fuel economic growth and the elimination of corruption in the sector;
- Transforming the institutions to be transparent and accountable to the consumer and the public and reforming the governance process through a sustained public outreach and public participation approach;
- Building sustainable capacity through knowledge and information networks, strategic partnerships among stakeholders, training, peer exchange, distance learning and other mechanisms to create a cadre of energy professionals committed to cause sector reform through locally developed solutions;
- Mobilizing increased private sector participation in clean energy development and management to foster environmentally sound and sustainable development; and
- Increasing international energy trade and energy security as important instruments of economic globalization and sustainable development.

In the industrialized countries these challenges include (i) proceeding towards full competition, (ii) further advancing privatization, (iii) increasing private investment, (iv) imposing tougher environmental standards, and (v) enhancing energy efficiency, reliability, and security. In developing countries and transitioning economies, the focus needs to be to (i) advance sector reform through enhancing sector governance and efficiency, (ii) commercialize energy enterprises and consolidate electricity markets to allow for competition, (iii) attract more private investment, (iv) increase consumer benefits, (v) expand access to modern energy, and ensure reliability and energy security, and (vi) ensure efficient and environmentally sustainable supply and use of energy. Central to achieving these objectives is the transformation of the energy sectors through best practices and sector governance.

On a practical level, therefore, proper governance of the energy sector requires the following:

- An open and transparent approach to sector policy making based on the rule of law, adequate consumer voice, transparent and accountable budgeting and sector financing, and a policy environment conducive to private sector investments.

- An independent regulator and effective consumer watch so that the government and the energy enterprises are accountable to the civil society. This will build the society's confidence in and acceptance of the sector governance.

- Modern management of the enterprises based on internationally acceptable accounting practices and customer service orientation.

The four pillars that define governance include (i) access to reliable and transparent information, (ii) open and frequent access to civil society participation, (iii) access to justice, and (iii) the capacity of governments to put the access principles into practice. This approach was tested in nine countries (Chile, Hungary, India, Indonesia, Mexico, South Africa, Thailand, Uganda, and the United States) in 2001-02, refined in 2003, and is currently being used to assess the quality of environmental governance in 20 countries worldwide. There is considerable empirical evidence that these general governance principles lead to more efficient energy sectors and broader public good - including a well served society.

Why a Regulatory Body in the Energy Sector

Economic development requires the public and private sectors to work hand-in-hand towards a common goal. Provision of reliable and affordable energy is crucial to any desired level of development. It is an indisputable fact that competition and private sector efficiency serve the consumer better than monopolistic approaches to public service. This is clear by the decisions made by virtually all the emerging economies in Asia, Central Europe, the former Soviet Union, and the Caucasus regions. Therefore transparency, accountability, and rule of law are essential in order to guide and regulate the market players in the energy sector. Once again, it has been demonstrated that establishing an independent regulatory authority is a crucial factor in the success of any country's effort to introduce competition and to privatize and liberalize the energy sector.

The generally accepted role of the regulator encompasses the following:

- **Encouraging competition, preventing monopolistic behavior, and regulating the energy market.** This includes responsibilities such as granting licensing, promulgating standards, developing and implementing rules that are transparent and fair.

- **Ensuring that energy enterprises are financially viable and are able to serve the consumer with reliability**. This area includes tariff setting based on cost recovery, requiring enterprises to provide energy to consumers on a fair basis, and balancing the sector ownership and diversity of market players.

- **Ensuring that the consumers are served efficiently and fairly.** An important element of the regulator's responsibility in this area is to provide the consumers a forum for public hearing, complaint resolution and public opinion on how the energy enterprises should be behaving. It is through this open and transparent process that the regulator plays an important role of increasing consumer confidence in the market players and the government policy makers.

- **Implementing the government's subsidy program for vulnerable consumers and selected market players (i.e., rural energy service providers).** An independent regulator run based on an open and transparent governance process without interference from either the government policy makers or the energy industry instills greater confidence in the society in the rule of law and market behavior.

- **Designing and implementing both incentives and penalty schemes in order to ensure that the market performs based on clearly articulated rules and procedures.** This is another major area where the independence of the regulator must be preserved and not compromised. Typically, the system has been abused by both the governments and the industry, and the consumer has suffered.

Regulatory agencies have taken many forms. Some countries have regulatory departments within a government ministry, thereby compromising the independence of the regulator. In the case of other countries one finds regulatory bodies that are separate organizations but are still accountable to a ministry or government body. In many developed economies, the regulatory agencies are legal bodies separate from and not accountable to any government ministry or department. A few countries have no regulatory bodies and regulate energy service providers through the country's antitrust or consumer-protection laws. Inevitable conflicts of interest arise when a government controls both the regulatory agency and the dominant players in the market. There is no "one size fits all" model for a regulatory regime and while conventional wisdom mandates that the regulator be completely independent of the government and market influence, in recent years some hybrid approaches have been used whereby the government, industry, and the regulator share certain functions. Regardless of the model, the central objective of emerging economies should be to create a regulatory body that has (i) substantial autonomy from short-term political and other interventions, (ii) adequate authority to establish sound regulatory practices (e.g., tariffs, licenses and monitoring), and (iii) clear accountability to assure transparency and credibility. A sound, transparent and stable regulatory body and process is important for the government, consumers and investors alike.

Regulatory Reform and Governance at the ECB

The development of regulatory regimes in the energy sector in Southern African countries is a relatively new development. As of now, only six countries in the Region have functioning regulators and many of them are undergoing a fast pace of reform in a rapidly changing power sector landscape. Regional organizations such as the Regional Electricity Regulators Association (RERA) and Africa Forum for Utility Regulators (AFUR) are very active in mobilizing international best practices in regulatory governance through regional workshops and regulatory exchanges funded under the USAID grant to National Association of Regulatory Utility Commissioners (NARUC), U.S.A. While these regional activities are very helpful in information and best practices transfer to the Region, more practical and targeted training is still needed on specific topics relevant to the decision making challenges that ECB is currently facing and new challenges that will come forward as Namibia's power sector goes through reform and restructuring including the introduction of IPPs in the Namibian power market.

B. SPECIFIC CAPACITY BUILDING AND TRAINING NEEDS OF ECB

Exhibit VI-1 provides a compendium of potential training needs of ECB managers and staff over the next two years. This list of training requirements is tentative and should be finalized and prioritized through a detailed Training Needs Assessment (TNA).

EXHIBIT VI-1: TRAINING AND CAPACITY BUILDING NEEDS OF ECB

(ILLUSTRATIVE LIST)

Training Area	Duration	Items to be Covered
1. Change Management in Regulatory Responsibility and Functions	1 week	• Best Practices in Regulatory Models in a Reforming Power Sector • Information needs, Information Flow, and Decision Making • Communications and Outreach and Transparency and Accountability • Stakeholder Coordination • Public Hearing Process • Case Studies and Role Playing
2. Tariff Development, Subsidy Management, and Tariff Review	1 week	• Methodologies for Different Types of Tariff • Cost of Service Determination and Tariff Setting • Subsidy Targeting and Administration • Process for Review of Tariff Proposals • Case Studies and Role Playing
3. Competitive Tendering Process for Small IPPs	1 week	• Preparation of Model tender Documents • Standard and Transparent Process for Tender Evaluations • Preparation of Standard Licensing Documents • Criteria for Award of Licenses and Transparency in the Process of Award • Procedures for Appeals and Dispute resolution • Case Studies and Role Playing
4. Performance Benchmarking and Technical Standards for IPPs	1 week	• Technical and Quality Standards for Different IPPs • Grid interconnections Regulations • System technical Requirements
5. Negotiations with Large IPPs	1 week	• Rules of Engagement • Principles of Negotiation • Balancing of Equities • Risk Allocation Formulas • Cost Allocation Principles

Training Area	Duration	Items to be Covered
		• Default Clauses • Environmental Regulations and Compliance • Safety regulations and Compliance
6. Techniques in Risk Mitigation and Cost Allocation for Large IPPs	1 week	• Identification of Risks • Methodologies to Quantify and Convert risks to Costs • Risk Mitigation Intervention Best Practices
7. Wholesale and Retail Markets and Competition	1 week	• Wholesale Market Models and Competition Rules and Procedures • Retail market models and Competition Rules and Procedures
8. Quality of Supply and Customer Service	1 week	• Power Quality Standards for All Power Generators • Customer Service Standards • Penalties and Administration Procedures
9. Regulations in Distribution Management	2 weeks Or two one-week courses	• General Regulations on Distribution Business Management • Systems Standards • Safety and Reliability Standards • Financial Performance of REDs • Customer Service Regulations • Operation and Maintenance Standards and Compliance Procedures • Outage Management, Fault Management, and System Planning
10. Contracts Dispute Settlement and Arbitration		• Contract Dispute Settlement Procedures and Rules • Arbitration Procedures and Rules • Penalties and Enforcement • Best Practices in Dispute Resolution and Arbitration
11. Rural Electrification Planning	1 week	• Regulations for rural Electrification • Regulations for Rural Electric Utilities (REUs) • Other Regulatory interventions such as Customer Service, Quality of Supply, Customer Complaint redress, Etc.

The above list of training programs is a tentative list and is not all inclusive as training may be needed in various other related areas.

VII: ADDITIONAL ITEMS IN CORE INTERNATIONAL'S TERMS OF REFERENCE

CORE International's Terms of Reference in its contract with ECB include a number of additional items – model fuel supply agreement, construction agreement elements, implementation agreement elements, operations and maintenance agreement elements, and land conveyance issues. This section provides brief descriptions of these instruments and list typical elements included in these documents.

A. MODEL FUEL SUPPLY AGREEMENT

Fuel Supply Agreements (FSAs) are a critical element of any IPP project and often require careful orchestration and extensive negotiations. Apart from the usual clauses related to the roles and responsibilities of the parties, the following specific clauses are common to most FSAs:

The following

1. Term of the Agreement
2. Termination and Cancellation Conditions and Procedures
3. Conditions Precedent - requirements for buyer to have financing and facilities for fuel receiving and storage
4. Source of Fuel and Fuel Supply
5. Substitute Sources
6. Delivery Procedures, Schedules, and Guarantees
7. Default Clauses and Penalties
8. Quantities of Fuel Supply
9. Fuel Storage and Security
10. Insurances
11. Prices, Currency, and Exchange Rates
12. Force Majeure

An illustrative Fuel Supply Agreement for a real project is outlined in Annex 12.

B. CONSTRUCTION AGREEMENT ELEMENTS

The purpose of the construction agreement is to govern the construction phase of the IPP project and to address the risks of that phase. Such an agreement should be modeled closely along guidelines such as FIDIC's standard contracts. Some key features are listed here:

General Provisions
This section deals with the general issues of the contract such as:

- Definitions, Interpretation
- Communications, Law and Languages
- Assignment
- Confidentiality
- Compliance with Laws
- Joint and Several Liability
- Documents

The Employer

This section sets out the details and rights of the Employer and deals among others with the following:

- Access to site
- Permits, licenses
- Staff
- Financial Arrangements
- Claims
- Employer's Representative
- Delegated Persons
- Instructions
- Determinations

The Contractor

This section sets out the details and rights of the Contractor and deals among others with the following:

- General Obligations
- Performance Security
- Representatives
- Subcontractors
- Safety
- Quality Assurance
- Sufficiency of the contract price
- Access, rights of way and facilities, site security
- Transport of goods, equipment
- Protection of the environment
- Electricity, water and gas
- Progress reports
- Unforeseeable difficulties

Design

The design clause is relevant for EPC contracts where the contractor has design obligations and should deal with the following:

- General design obligations
- Documents, both design and as-built
- Technical standards and regulations
- Training and manuals
- Design error

Staff and Labor

This clause deals among others with the following:

- Engagement, rates and conditions for staff and labor
- Use of local labor
- Labor laws and compliance therewith
- Work permits for foreign staff
- Working hours
- Heath and safety
- Facilities for staff and labor

- Supervision
- Records of personnel and equipment
- Disorderly conduct

Plant, Materials and Workmanship
This clause should deal with the quality of work and materials, such as:

- Manner of execution
- Samples
- Inspections
- Testing
- Rejection
- Remedial work
- Ownership of plant and materials
- Royalties

Commencement, Delays and Suspension
This clause deals with the timeline of the construction project, such as:

- Commencement of works
- Program and time for completion
- Extensions of time for completion
- Delays and damages
- Suspension of work (including consequences and payment)
- Resumption of work
- Taking over of works and sections
- Interference with tests

Completion, Tests
This clause should deal with completion procedures and testing before and after completion, such as:

- Contractor's testing obligations
- Delayed tests and retesting
- Failure to pass tests on or after completion
- Procedure for tests after completion

Defects Liability
This clause should deal with defects and procedures and liabilities surrounding defects, such as:

- Completion of outstanding works and remedying defects
- Cost of remedying defects
- Extension of defects notification period
- Failure to remedy defects
- Removal of defective work
- Right of access
- Performance certificates
- Unfulfilled obligations
- Clearance of site

Variations and Adjustments
This clause should deal with adjustments that may be made to the contract during execution, such as:

- Rights to vary
- Value engineering
- Variation procedure
- Currencies
- Provisional sums
- Day work
- Adjustments for changes in legislation
- Adjustments for changes in cost

Contract Price and Payment
This section should deal with the main financial issues of the contract, such as:

- Contract Price
- Payment scheduling
- Process for claims and payments
- Interim payments
- Delayed payment
- Retention money and payment thereof
- Statement at completion
- Application for final payment
- Discharge
- Final payment
- Cessation of Employer's liability
- Currencies of payment
- Taxes, duties and levies

Termination and Suspension
This clause should define the various scenarios for suspension and termination, such as:

- Notice to correct
- Termination by Employer
- Valuation and payment upon termination
- Employer's entitlement to termination
- Contractor's entitlement to suspend the work
- Termination by contractor
- Cessation of work and removal of Contractor's equipment

Risk and Responsibility, insurance
This clause should be designed to apportion and define risk and responsibility such as:

- Indemnities
- Contractor's care of works
- Employer's risks
- Consequences of employer's risks
- Intellectual and industrial property rights
- Limitation of liability
- Insurance of works and contractor's equipment

- Insurance against injury of persons or damage to property
- Insurance for contractor's personnel

Force Majeure
This clause should define force majeure and processes to be followed in case thereof, such as:

- Definition of force majeure
- Notice of force majeure
- Duty to minimize delay
- Consequences of force majeure
- Force majeure affecting subcontractors
- Optional termination, payment and release
- Release from performance under the law

Claims, Disputes and Arbitration
This clause should define how claims and disputes will be handled, such as:

- Contractor's claims
- Dispute adjudication process
- Amicable settlement
- Arbitration
- Failure to comply with dispute adjudication decisions

The full text of such an agreement can be obtained from FIDIC[26].

C. IMPLEMENTATION AGREEMENT ELEMENTS

The purpose of the implementation agreement is to govern the implementation of IPPs through whatever schemes may be implemented, e.g. through tender processes, through unsolicited bids or through issuing policies which promote IPPs. It mainly deals with overarching issues and policy or framework issues.

Some elements hereof will be the responsibility of MME, some ECB, some NamPower trading or other developers, depending on the scale of the IPP, the IPP development approach selected by ECB and MME and the scale of an individual IPP project.

Power Purchase Agreement
The power purchase agreement (PPA) is critical to the development of any IPP. Different approaches are required depending on the scale of the IPP envisaged.

a. **Large IPPs**

Large IPPs will require custom designed and negotiated PPA and will not easily be able to use standard PPAs except possibly as guideline. It is therefore expected that the IPP developer and the intended power purchaser will develop and negotiate an IPP, with regulatory oversight to ensure that the key policy and regulatory elements applicable to the IPP are adhered to, e.g. generation pricing methodologies.

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[26]. *e.g. "Conditions of Contract for EPC Turnkey Projects", FIDIC, or similar as appropriate to the mode of a specific construction projects.*

b. Medium IPPs

For medium IPPs it is expected that a model PPA will be used which will serve as basis for limited negotiation between the IPP developer and the power purchaser. Some aspects of this PPA are likely to be standard and pre-agreed by the regulator and trader, other aspects will be subject to negotiations. Again the rules, regulations and policies must be adhered to and regulatory oversight must be built in to ensure that the final product does comply with requirements.

c. Small IPPs

For small IPPs it is envisaged that a standard PPA be utilized in which most clauses are pre-agreed by the regulator and the anticipated purchasers (NamPower Trading and the REDs). Only some commercial aspects and detail operational clauses are likely to be subject to negotiation, as they will depend on the various possible types of power plant which can be quite diverse and may require some individualization of the PPA.

Market Rules for Private Participants
In order for private participants to enter the market there need to be clear rules which are published and for which there is a visible commitment that they will be enforced and adhered to by the key players. The ECB has already developed a transmission grid code which forms part of such a market framework, but efforts to develop a Single Buyer model have failed, mainly due to disagreement between ECB and NamPower about this model and its suitability to Namibia. It is therefore critical that this debate be re-opened and settled so that clear rules can be developed and published through which IPP developers can understand their place in the market and be assured of fair and transparent treatment.

Tenders for Medium and Small IPPs
The most likely approach to succeed in getting small to medium IPP development is through tenders for such projects. The projects so identified as desirable for Namibia would emerge from a resource planning process driven primarily by NamPower (on account of their being in possession of the best information and tools for this task) but must involve other stakeholders, specifically ECB and MME to reduce perceptions of planning bias.

The tender process for such tenders should also be developed. Such a process should address the issue of the Trader being an integral part of NamPower and hence its independence as possible bias in bid design and evaluation must be addressed.

Implementation of Key Elements of the Regulatory Model
The ECB should clarify when and how they intend to roll out the implementation of the key elements of the regulatory model regarding IPPs. This would involve a timeline for roll-out and some details of the envisaged phases of IPP development and promotion.

Implementation of Regulatory Capacity Building
The ECB should clarify the capacity building that it needs to effectively deal with the requirements of the envisaged IPP program, including resources to be acquired. The implementation plan for key regulatory model elements should serve as guideline to determine resource and capacity requirements at the ECB (or possible other entities such as NamPower Trader) and to design capacity building programs accordingly. This will give prospective IPP developers the assurance that the IPP program will be handled competently and transparently.

Procedures for Regulatory Actions
Potential IPP developers, especially private sector players, will need to understand how the regulator intends to run the IPP program and what procedures will be put in place from a regulatory perspective to ensure transparency, fairness and a level playing field, especially in the face of NamPower's dominant role in the local power market. The ECB should therefore develop and publish procedures for all the important regulatory actions in relation to the IPP program to ensure transparency and predictability.

D. OPERATIONS AND MAINTENANCE AGREEMENT ELEMENTS

The purpose of the operations and maintenance agreement is to govern the standards to which the power plant will be maintained and operated.

The following sections highlight some of the key elements that need to be dealt with in such an agreement.

Maintenance
The purpose of maintenance is to ensure that the plant remains in good running condition that the life of the plant is maximized and that operational availability and efficiency are maximized.

1. Maintenance Standards & Planning

The approach towards maintenance planning should be agreed, i.e. condition based maintenance, breakdown maintenance, scheduled maintenance. Different parts of the plant will require different approaches. Many maintenance items will be specified by the equipment supplier and these need to be taken into account. Maintenance procedures and approaches should generally be agreed to be aligned with international best practice for similar plants in similar circumstances.

2. Maintenance Impact on Availability

The maintenance part of the agreement relates closely to the operations part since maintenance has a profound impact on availability and efficiency of the plant. The maintenance needs of the plant need to be clearly understood and defined, and subsequently the impact of those maintenance needs on plant availability can be determined and included as parameters in the plant availability and performance requirements.

The availability of parts and personnel for emergency maintenance or repairs should also be specified, keeping in mind that higher availability costs more and may be difficult to ensure especially if the plant is located remotely. The costs and options need to be weighed carefully before the best option is determined.

3. Personnel and Equipment

This section should specify what maintenance tools and equipment must be available on site or from specified backup locations within a specified time. This should cover special tools and equipment required for troubleshooting and repairing common problems. It should also specify the number, qualifications, experience and specializations of maintenance staff, both on site and off site. For off site staff availability and arrival time should be specified.

The on and off site balance of these resources will be more critical for remotely located power plant than for those at or near larger existing towns.

4. Spare Parts Inventory

During the construction phase an inventory of critical and maintenance spares should be procured which will be left in the care of the O&M operator. The agreement must specify the list of such spares as an annex and clarify the time from which the operator assumes responsibility for such spares. The insurance needs of such spares should be specified, and the requirements for keeping the register up to date, including the keeping of records for when and where spares were used.

5. Record Keeping & Information Provision

The agreement should specify the record keeping requirements in terms of maintenance and should cover at least the following:

- Structure and frequency of records
- Data details to be recorded
- Software to be used for storing data
- Ownership of such software and data
- Backup procedures, both computer as well as paper
- Period for which records of various types must be kept
- Archiving procedures
- When, how and what information must be routinely reported on and to whom
- Who must be notified how of what events

6. Costs and Payments

The agreement should specify the costs and payment procedures for the various maintenance elements and should cover at least the following:

- Payment frequencies and schedules
- Price schedules for maintenance items
- Fixed price for standard maintenance
- Currencies
- Taxes and duties
- Claims and invoicing procedures

Operation
Operation is concerned with running the power plant as dispatched.

1. Operation Standards

Operation standards need to take into account the specifications of the equipment supplier as well as the operating regime and dispatch regime imposed by the power purchase agreement. Operational standards which comply with best practice and meet the requirements set by the manufacturer and power purchaser need to be specified in the clauses of this section.

This should also include advance notices of planned outages, advance notice of network maintenance which may affect the plant’s ability to supply power to the purchaser.

It should also specify the requirements for plant operators – qualifications, training, and experience – as well as supervision requirements.

The operating standards need to specify what services are to be provided, for what period, with what lead times or notice periods, by what resources and to what standard.

2. Operational Performance

Plant availability and efficiency need to be defined, if appropriate for various foreseeable operating modes and conditions. Penalties may be considered for performance that does not meet the specified standards, while bonus remuneration may be considered for performance that exceeds the specifications by a given margin.

3. Operating Costs

This relates to the financial aspects of the O&M agreement, i.e. how much the operator which charge for operating and maintaining the plant. This is likely to be specified in detailed schedules which contain both fixed monthly or annual costs for providing basic foreseeable services as well as rates for additional ad-hoc services.

A process for determining and approving costs for unforeseen and/or unspecified services needs to be put in place so that a framework exists for dealing with unforeseen circumstances.

The agreement should, among others, cover the following:

- Payment frequencies and schedules
- Price schedules for operation service items
- Fixed price for standard operations
- Performance bonus and penalty provisions
- Currencies
- Taxes and duties
- Claims and invoicing procedures

4. Record Keeping

The agreement should specify the record keeping requirements in terms of operations and should cover at least the following:

- Structure and frequency of records
- Data details to be recorded
- Software to be used for storing data
- Ownership of such software and data
- Data backup procedures, both computer as well as paper
- Period for which records of various types must be kept
- Archiving procedures
- When, how and what information must be routinely reported on and to whom
- Who must be notified how of what events

General
The following are the main general clauses that are included in typical Operations and Maintenance Agreements.

1. Force Majeure

Force majeure events need to be considered and dealt with, clarifying responsibilities, notifications, remedies, reinstatement clauses. The agreement may foresee certain types of force majeure events, specifically related to labor issues or climatic/environmental influences, and these should be dealt with separately from general force majeure provisions if applicable and appropriate.

2. Dispute Resolution

A dispute resolution procedure should be laid out. Typically this will specify

- How notice of dispute must be given
- What steps of dispute resolution will be followed

Typically, disputes may be subject to a structured dispute resolution process involving an adjudicator, failing which they may be arbitrated with or without recourse to the courts as a last resort.

3. Insurance

The agreement should specify what insurance cover must be taken out by which party, to what amounts, for what events and/or equipment. Insurance should also cover third party liabilities such as injury to persons and damage to property; it should also cover appropriate insurance for the contractor’s employees.

4. Labor Disputes

The agreement may need to deal separately with the possibility of labor disputes and how they may be resolved and how the risk of the possible effects thereof will be shared between the parties.

E. LAND CONVEYANCE ISSUES

The following clauses are typically considered in all agreements related to land conveyance. In the case of IPP development, land conveyance is a big issue as the developer enters into an agreement with the government on land conveyance and land use.

Land Ownership
In surveyed areas land ownership is registered and land can be bought and sold. In such areas an IPP would normally purchase the land on which the plant is to be built, unless it is a mobile plant which does not remain on one site for significant periods of time.

In commercial farm areas, where some small IPPs could be located, a portion of the land would normally be purchased from the land owner in a commercial transaction at negotiated price. The portion of the land would be surveyed by a registered land surveyor, and registered as sub-division at the deeds office in the name of the IPP developer who would hence gain full rights to the land.

A legal practitioner would normally be employed to arrange the transfer of ownership and deeds registration. The legal fraternity has standard rates for such services.

In local authority areas land ownership is also registered and transfer of properties is also subject to deeds registration. In such areas the zoning of properties is important, and the developer may need to apply for re-zoning of properties if required. This is normally a process involving public notices inviting comments and objections to the proposed re-zoning.

In the case where significant amounts of farm land are needed then the land redistribution program in Namibia may become an issue, since economic units of land have to be offered to Government first before being sold in the open market. Government therefore has the right of first refusal to any large farm land transaction. This is however not likely to an issue for most IPPs since they are not likely to require such significant amounts of land in farming areas.

Permission to Occupy (PTO)
In communal land areas there is no land ownership by private entities or persons *per se*. Land rights in such areas are acquired through a permission to occupy (PTO), which is normally issued for a set period of time. The PTO is obtained from the relevant local or regional authority with jurisdiction over the land in question.

Movable Plant
Some potential IPPs may be movable installations (e.g. potential small thermal plant fuelled with intruder bush in commercial farm areas). Such plant would require permission from the registered land owner to occupy a specified area of land for a specified period of time and to undertake certain specified activities on such land (e.g. removal of certain types of bush). Such an agreement would also need to deal with issues such as

Access to the Site
Such a clause needs to specify via which roads the site may be accessed, at which times such road may be used, procedures for locking of gates, responsibility for maintenance of access roads.

Access to Water
Access to water for drinking and other purposes is a sensitive issue in most areas of Namibia. Rights to utilize existing water sources need to be specified, i.e. quantities that may be used, tap of points must be specified, costs and metering need to be specified.

If new water sources are to be developed this will also need agreement with the land owner, specifying location of such developments, allowed extraction rates, ownership of the infrastructure, disposal when occupation ends.

In addition to permissions from the land owner it may be necessary to obtain water extraction permissions from the water authorities.

Removal of Waste / Environmental Protection / Pollution
Waste disposal is an issue in rural areas and on farmland. Normally the land owner will expect proper waste disposal, i.e. removal of non-biodegrading waste and proper local disposal of degradable waste to ensure that wildlife and livestock do not have access to waste.

Restoration of the Site upon Termination

Restoration of the site after completion of activities should form part of such an agreement so that it is clear who takes responsibility for restoring the site as well as the condition to which the site is to be restored.

Precautions for Fires

Sites in remote areas where people live usually have a fire issue due to people cooking with fire. On farmland this poses a major risk of wild fires which devastate large tracts of farmland in Namibia every year and cause significant damage and losses. An agreement for site access and use will need to specify fire precautions that are to be taken, conditions under which and places where open fires may be used and apportionment of liability and insurance in case of fires spreading.

Access Control / Livestock Control

Where a power plant is sited on farm land livestock and access control is an issue that needs to be dealt with in an agreement. This should specify rules regarding the closing and locking of gates. It may also be expedient to deal with the camping off of the power plant site and possibly its access road to avoid disputes over access or livestock losses. Compensation procedures and rules should be clarified in case livestock is lost as a results of the activities.

Poaching

Poaching by workers at the power plant is likely to be an issue to the land owner and must be dealt with in the agreement, i.e. prohibition of poaching should be specified, and if limited hunting is allowed then this needs to be specified in detail, including compensation therefore if any. Recourse and compensation to accrue to the land owner in case of unauthorized hunting should also be specified, e.g. that employees of the power plant operator caught in such act may be removed from site.

Insurance

The agreement should specify the type and extent of insurance required to be obtained by the power plant operator in favor of the land owner for possible losses, specifically related to such eventualities as bush fires and livestock losses.

VIII. CONCLUSIONS AND RECOMMENDATIONS

This section contains a summary of the key findings of the CORE Team for each of the substantive areas of the technical assistance. Where appropriate, recommendations regarding each subject area are provided for consideration by the ECB as it moves forward.

Electricity Supply and Demand in Namibia

One of the first tasks conducted by the CORE Team during the technical assistance was to assess the current status of the power sector in Namibia. This was necessary to define the context within which any new IPPs will potentially make an entry in the sector. Specifically, the CORE Team reviewed the current electricity supply, demand, and pricing issues in the country to develop a baseline for the rest of the technical assistance.

Findings:

1. Namibia's demand is quickly outgrowing its traditional source of supply in South Africa. The Caprivi Link will buy only two more years before additional sources of supply are needed.

2. The Namibian power system is based on hydro and thermal generation sufficient to meet minimal demand conditions. At present, the system relies heavily on imports from Eskom to meet base load electricity demand and indigenous hydro to meet most of the peak demand. The current peak demand for electricity in the country is 400 MW, which exceeds the current NamPower generation capacity by about 5%. Captive generation in the mining industry is probably capable of preventing an overall shortage of electricity, at least for a short period of time.

   Generation capacity, aside from standby generation in the mining industry and a few isolated generating sets, consists of three power plants. These are:

Namibia's Power Generation Plants, 2005	
Plant	Capacity
Ruacana	240/249 MW
Van Eck	120 MW
Paratus	24 MW

The new Caprivi Link with Zambia will provide a little less than 100 MW of new capacity to the system. This transmission link is expected to become operational in late-2006 and will provide for about 2-3 years of demand growth.

3. NamPower's Base Case forecast for electricity demand shows that even under rather modest assumptions, the demand for electricity will approximately double by 2020. Over the next few years, as the surplus from South Africa, traditionally meeting more than half the country's electricity demand, continues to fall, Namibia will need to look at new sources of supply. The following figure shows the short term supply-demand balance for the

country, assuming that both the Caprivi Link and Kudu are completed on time (2006 and 2008, respectively).

4. A successful implementation of the Vision 2030 would result in a quadrupling of electricity peak demand by 2030, requiring not only the Caprivi Link and Kudu, but also a number of other sources of electricity generation.

5. The same factors that drive the domestic demand for electricity – population growth, mining activities, tourism, and rising affluence – also operate in the main electricity supplier, South Africa. There, Eskom has faced unprecedented difficulties in meeting demand growth and has unveiled an ambitious program to increase capacity significantly over the next ten years. The implications for Namibia are as follows:

    - Eskom will have its hands full meeting domestic electricity demand over the next 10-15 years;
    - Transmission capacity within South Africa needs to be significantly augmented in the short term;
    - New generation stations are likely to cost more than the older technologies that they replace;
    - Bringing old plants out of mothballs will likely lower the overall level of system reliability; and
    - South Africa faces unprecedented challenges from shortages of skilled labor and project management to meet its stated construction goals and deadlines.

Electricity Pricing Issues in Namibia

Findings:

1. New sources of electricity will be considerably more costly than current supplies. The discussion on the looming change in electricity supply economics in this report has been supported by the recent changes in power supply contracts from Eskom. With South Africa no longer willing to provide long-term fixed price contracts to NamPower, this can only mean higher electricity prices in Namibia.

2. New sources of supply can provide some negotiating leverage with Eskom, but the inevitable acquisition of new generating capacity at world prices, rather than the special low costs of the 1970s in South Africa, means higher electricity prices throughout the Region. This finding has already been reflected concretely by rising prices on the Southern African Power Pool trading market.

Recommendations:

1. Namibia will need to (i) maintain a more flexible tariff structure to cope with variable prices for electricity and (ii) pay significant attention to the economy in acquiring new supplies which can be facilitated by improved regulatory oversight of, and cooperation with, NamPower.

2. Namibia will have to adapt to this change in its electricity supply conditions by making sure that the prices received from customers will support the prices paid to suppliers. This requires that the domestic tariff system be keyed to the sources of supply, adjusted in synchronization with changing supply costs and be overseen by a more proactive regulator.

Electricity Market Model for IPPs

Findings:

1. Namibia has moved appropriately to restructure its electricity sector to a modified single-buyer market and has achieved most of its objectives in that vein. NamPower has been ring fenced into business units that carry separate financial accounts and operational controls, with NamPower Trading acting as the electricity system's Single Buyer and only trader thus far.

2. A pure single-buyer market is not appropriate for the country and introduces unnecessary limitations on the flexibility that a small nation can have in its power supply decisions.

3. At the same time that Namibia has settled on a single-buyer model, most restructuring programs in neighboring countries have become stalled, limiting the usefulness of further moves toward a more liberalized market environment. It may be inappropriate for Namibia to expose itself to additional market risk until the relevant market institutions (e.g., the Johannesburg Power Exchange) have been fully established and opened to outsiders.

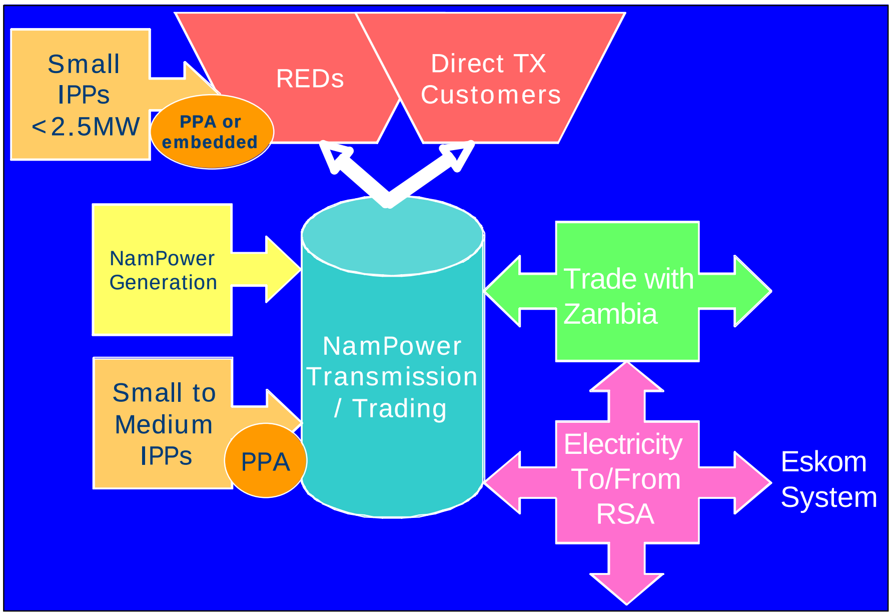
4. Most current problems on the generation and supply sides are appropriately handled through regulations rather than further extensive legal restructuring of the country's utility system.

5. To integrate large IPPs, a slightly modified single-buyer approach can be used as discussed in Section II. C and Section III. A. Under the current model, NamPower Trading remains the sole off-take purchaser of electricity from Kudu or another large IPP. In the modified single-buyer approach, some larger companies will sign PPAs with the large independent generator, permitting NamPower Trading to reduce its market risk. This is in reality a financial risk sharing mechanism, since the excess power is routed through NamPower Trading in either case.

6. For Medium and Small IPPs the relevant access is to transmission and distribution, respectively. A suggested variant on the Single-buyer model for these smaller IPPs is shown in Exhibit VIII-1. This Medium and Small IPP model accounts for the differences between projects that use standard technologies and renewable fuels in multiple locations at the smaller end of the scale and those using one-off fuel and technology combinations at the large end. Smaller IPPs that wish to sell electricity into the national system must face several hurdles: (i) a lack of a direct connection and easily adapted PPA structure for sales to NamPower transmission and trading for medium IPPs, (ii) a lack of a readily-available contract structure to sell directly to the REDs, in the case of small power plants, and (iii) the need for modified single-buyer model to facilitate small IPPs.

Most of the structural and contractual arrangements noted above can be implemented without a thoroughgoing legal de-integration of the NamPower system. As has been observed, Namibia's neighbors have yet to fully liberalize their systems, and as long as this is the case Namibia would find itself negotiating with state-owned power companies from a position of weakness while capacity for generation and transmission is short region-wide.

EXHIBIT VIII-1: MODIFIED SINGLE BUYER MODEL FOR SMALLER IPPs



Recommendations:

1. NamPower and the ECB should hold off on additional legal and financial restructuring once the single-buyer market is fully established;

2. Medium IPPs should sell to NamPower Trading;

3. Small IPPs should be imbedded in the REDs and will need specific access to sub-transmission; and

4. Enabling several specific regulatory actions at ECB can reduce investor perceptions of bias by NamPower in its planning and operations, thereby encouraging additional activities by investors.

The recommendation that ECB take some regulatory steps to entice investors in IPPs to Namibia is part of the overall recommendation for Namibia to rest at the single-buyer stage of restructuring for the foreseeable future. In a system with an integrated utility that is internally unbundled, there are often perceptions of bias in the way that the utility relates to outside investors. These perceived biases may deter investment. They can be significantly mitigated with the specific activities by ECB and NamPower, acting in concert, as shown in Exhibit VIII-2.

The findings and recommendations for market structure translate straightforwardly to the recommended methods for acquiring new generation capacity from IPPs. These findings and recommendations are discussed below.

Proposed IPP Models

Findings:

1. Competitive procurement of large IPPs often results in underbids and poor performance

2. Many elements of a large IPP can be competitively procured, including fuel and the EPC

EXHIBIT VIII-2: BIASES AND POTENTIAL MITIGATION MEASURES

Perceived Bias in a Single-Buyer Market and Mitigation Measures		
Problem/ source of bias	**Mitigation Measure**	**Benefits**
Investment Planning & Plant Specification	ECB active oversight & joint due diligence with NP	Reduces bias, Increases investor confidence
Bid Evaluation	ECB/NP due diligence exercise	Same as above
Plant Dispatch/ availability	Publish ex ante results of dispatch	Increased transparency & confidence

3. Most large project PPAs will be negotiated from scratch

4. Many of the large IPP project disasters worldwide can be traced to a lack of synchronicity between fuel and power prices on the supply side and prices paid by electricity customers on the demand side

5. Most Medium and Small IPPs use standard technology and can be competitively procured; and Small IPPs need to reduce transactional costs in order to be competitive.

6. In Namibia the opportunities for building large IPPs are relatively limited. Looking at plant sizes above 100 MW, there may be opportunities to build one large gas-fired plant (Kudu), one or two coal-fired plants (Walvis Bay), and one large hydro station (upstream of Ruacana). If each project is only one of its kind in the country, then it is unlikely to be worthwhile spending the time and resources to develop standard contractual formats for such plants. Countries that have used negotiated procurements with tight specifications have had fewer problems with variances in performance and emissions.

7. Competition can still play a role in the Large IPP market. As a general rule the more units to be procured, the more standard the technology and more competitive the fuel supply, the more likely it is that competitive procurement can be used for some elements of such plants. If a standard technology is to be used for a large power station, then it should be possible to obtain multiple bids for the EPC contract (at least 3-4 potential bidders). Most of the benefits of a fully competitive procurement in Namibia can be obtained with far fewer downside risks through competitive EPC and fuel supply agreements.

8. Fuel supply is another area in which it may be possible to obtain competitive results without a fully competitive power supply situation. If a power plant can be supplied using a reasonably generic fuel specification, then it should be possible to obtain multiple bids from potential fuel suppliers, increasing the overall competitive market content of the plant.

9. Due to the small size of the Namibian market relative to large IPPs, any new IPP will exercise significant influence on overall electricity pricing levels in the country. As a result, it will be necessary to integrate the fuel supply agreement (FSA) with the PPA. As has been demonstrated - mostly in a negative sense - around the world, if the FSA gets out of synchronization with the PPA, then one of the parties, or possibly either the consumers or the government, will be called upon to absorb the excess risk arising from the misalignment of risks to the various parties.

10. For smaller IPPs, both Medium (5-100 MW) and Small (<5 MW), it is expected that almost all of these projects will use renewable sources of energy and will be price takers. That is, the prices paid to the generator will reflect the prices in the NamPower system or in the RED system appropriate to the project. Smaller fossil power plants are simply not as fuel efficient or environmentally friendly (per kWh) as larger fossil plants.

Recommendations:

1. Large IPPs should be negotiated from single developers using tight specifications

2. Medium and small IPPs should be competitively procured with an open solicitation

3. The ECB should draw up regulations that maximize the competitiveness of fuel and equipment elements for large IPPs

4. ECB needs to make sure that the pricing adjustments for large IPPs are consistent, and in synchronization with those of the Namibian electricity market

5. ECB needs to draw up standard PPAs for smaller projects that include pricing adjustment provisions that reflect the wholesale market prices (for Medium IPPs) or the retail tariff structure (for Small IPPs).

6. ECB should play the critical role of ensuring that pricing risks are aligned appropriately between the FSA and PPA and the retail markets. It can do this through (i) exercising oversight on FSAs and PPAs and (ii) designing appropriate indexing tools for the domestic market to maintain reasonable synchronization of retail and generation prices.

7. The PPA should distinguish between plants that contribute capacity to the system and those that contribute only energy. For Medium IPPs, a capacity payment should be paid for plants that can be dispatched by the system operator. This will generally exclude wind plants but will include well-managed run-of-the-river hydro stations. Small IPPs that are embedded in the REDs will generally not be able to contribute capacity to the system and

should be paid on the basis of their energy contributions only. To reduce costs of doing business and to make sure that investors enter the market with appropriate expectations these pricing conditions should be laid out publicly by the ECB.

8. The roles of the three key governmental institutions, NamPower, ECB and the REDs will vary by project size. For large projects NamPower will be the customer and will conduct most of the negotiations, ECB should play a supporting role. For Medium IPPs, NamPower is still the customer, but ECB's role should be enlarged given the reliance of the Medium IPP contracts on standard provisions. For Small IPPs, the REDs should have overall authority, with ECB providing contracting assistance. For both Medium and Small IPPs NamPower should provide technical and safety assistance to provide for both standardization of design elements and to reduce transactional costs for investors.

Regulatory Model and Regulatory Strengthening

Findings:

1. Pricing issues for IPPs, especially the role of cost pass throughs, is one of the primary market and regulatory challenges facing the ECB as the IPP business develops in the country. Considerable analysis was done on this issue during the performance of the technical assistance and several specific remedies were identified as mitigating measures. The specific problems identified in the work on regulation included the following:

    - Creation of additional risk and uncertainty by ex post cost reviews
    - The <u>unreasonableness</u> of certain IPP costs
    - Lack of knowledge on the part of regulators about how much certain goods and services should cost
    - A belief that competitive procurement of IPPs will render moot the problems listed above.
    - Experience around the world with IPPs has indicated that most of the problems created by ex post cost and tariff reviews can be either mitigated or eliminated outright by a vigorous ex ante tariff review.

2. Even competitive procurements can result in excess costs, especially if it is assumed that all of the costs in the winning bid are at the lowest possible level and are largely uncontrollable. In most cases neither assumption is true and leads to a full pass-through of costs, many of which are at least somewhat controllable.

3. As is common in most countries at the beginning of introducing an IPP regime, regulatory barriers (perceived or real) affect both the decisions to entering the market and the speed of entry of prospective IPPs. Annex 8 provides a detailed discussion on the regulatory barriers and risk mitigation for IPPs in Namibia. Specifically, this Annex discusses regulatory issues related to pricing of services, rate design, and the allocation of costs within which IPPs should be addressed in Namibia.

    IPPs have found trouble when countries have gone through macroeconomic reverses or when the power sector itself is significantly out of alignment with the terms required by the governing PPAs. Annex 9 provides interesting insights based on an IPP study by Stanford University. The study concluded that PPAs failed in most countries when they were stressed by either macroeconomic issues (Argentina, Indonesia, Malaysia, Philippines), or by events in the electricity sector itself, as in China. In these cases, the allocation of risk to the government was no protection for the investors, though lenders tended to come out somewhat better. The only two cases where the PPAs have not failed, Mexico and Turkey, are instances where there was no stress testing of the PPAs. The study makes a strong case for "stress testing" of all PPAs to assess whether the contractual framework can survive severe changes in the pricing and operational environment.

4. During the technical assistance, the Team also analyzed the regulatory roles and responsibilities, focusing largely on ECB, in the pricing aspects of IPPs. Annex 7 focuses attention on the role of the regulator in designing a wholesale tariff that can accommodate changes in fuel prices and operating conditions. Annex 8 focuses on a detailed pricing and regulatory barriers analysis. The key issues analyzed are cost pass-throughs and competitive tendering for IPPs.

5. A final element of investigation in the regulatory task concerns the interface between the market model and the regulatory framework. One of the most vexing issues in any IPP régime is the question of bias by the incumbent and the consequent disincentives and increases in risk and uncertainty for potential IPP investors. The nature of this bias problem and potential mitigation measures are discussed earlier in this section along with the market model.

6. During various working sessions and workshops involving a number of ECB managers and staff throughout the technical assistance, the CORE Team identified a number of areas where ECB's regulatory capacity needs to be enhanced. There is a sense of urgency in this area, particularly as it is clear that the climate for the entry of potential IPPs is ripe despite the usual real or perceived barriers. Specifically, considerable capacity building and training of ECB managers and staff will be needed in a number of areas including, governance models, best practices in transparent rule making, consumer participation and customer protection, tariff setting, tender preparation and licensing process, and development of model contracts and licenses. Section VI.B of the Main Report includes details of the training needs of ECB as identified during this technical assistance.

Recommendations:

1. The CORE Team recommends that the ECB initiate a program for a detailed review process of competitive procurement tenders for IPPs as well as for reviewing applications for licenses from Small IPPs.

2. To mitigate the potentially adverse impacts of "competitive procurement bias," the CORE Team recommends the following:

   - Make use of performance benchmarks and incentives in pricing wherever feasible;
   - Use competitive tenders only where a standard resource with replicable technology is called for;

- Rely on negotiated transactions for "one of a kind" plants and for first investors in a particular technology.

3. It is recommended that Namibia note the experiences with PPAs in larger markets, especially in the failure to protect consumers, and to prepare contingency plans for the failure of PPAs for large projects. Examples of India and China offer great insight into designing a regulatory model to mitigate risks associated with IPPs.

4. The CORE Team recommends that ECB take an active role in assessment and approval of cost pass-through provisions for negotiated IPPs. For smaller IPPs cost pass-through conditions should be included in a standard contract format. Recommendations for the role of competitive vs. negotiated tenders revolved around issues of size, replicability and technological uniqueness. For larger IPPs it is recommended that negotiated tenders be the norm. For smaller, more standardized projects competitive procedures should be the norm.

5. ECB should implement the bias control measures discussed under the market model recommendations earlier in this section.

6. In the area of capacity building and training, it is recommended that ECB initiate a comprehensive exercise to develop a detailed training plan for ECB staff and managers along the lines of the preliminary training program developed and presented in Section VI.B in the Main Report.