GOVERNMENT OF THE REPUBLIC OF NAMIBIA

NAMIBIA ELECTRICITY SUPPLY INDUSTRY

NATIONAL INTEGRATED RESOURCE PLAN REVIEW AND UPDATE

FINAL REPORT

SEPTEMBER 2016

MINISTRY OF MINES AND ENERGY

Developed for the Ministry of Mines and Energy by the Electricity Control Board in consultation with the Electricity Supply Industry Stakeholders

September 2016

Ministry of Mines and Energy
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EXECUTIVE SUMMARY

The Electricity Control Board (ECB) was tasked by the Ministry of Mines and Energy (MME) to review and update the National Integrated Resource Plan (NIRP). Hatch, a Canadian Consultancy firm, was contracted to do the review and update of the NIRP for Namibia focusing on electricity. The NIRP is a 20 year electricity sector development plan. It aims to provide an indication of Namibia's electricity demand, how this demand could be supplied and the cost of supply. The NIRP does not deal explicitly with the overall energy needs for the country but focuses on electricity only. The plan is expected to be dynamic and be continuously revised and updated to incorporate the latest available information and technologies.

It was recognized that the review and update of the NIRP requires the input of all stakeholders in the Electricity Supply Industry (ESI) in Namibia and these were involved as participants in the NIRP review and update process and several stakeholder workshops were held to obtain stakeholder input. The principal goal of the NIRP project was to identify the supply mix of resources to meet the near and long-term electric power needs in Namibia in a sustainable, efficient, safe and reliable manner at the lowest reasonable cost. The NIRP is focused on electricity supply, but should also take into account the impact of developing other energy sources and demand side management measures capable of reducing electricity demand in Namibia. The NIRP report presents the recommended NIRP Plan and documents the development of the plans for new generation and transmission additions taking into account the increase in demand, the aging of the existing generation fleet, the possibility of curtailment of imports from other networks and the implementation of the security of supply aspects outlined in the 1998 White Paper on Energy Policy. This document, herein called Final Report, summarizes all project deliverables and presents the recommended base case expansion plan, as well as the implementation plan. In earlier stages of the project, estimates were prepared for the capital and operating costs and performance characteristics of power generating plants utilizing the different primary energy resources. The NIRP is a national level plan and the primary analysis as described above has been carried out as an economic analysis rather than a financial analysis.

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List of Abbreviations

BFB	Bubbling Fluidised Bed
CC	Combined cycle
CCGT	Combined Cycle Gas Turbines
CFB	Circulating Fluidised Bed
COP 21	21st Conference of Parties of the UNFCCC
CSP	Concentrated Solar Power
DC	Direct Current
DSM	Demand Side Management
ECB	Electricity Control Board of Namibia
EIA	U.S. Energy Information Administration
EPC	Engineering, Procurement and Construction
ESI	Electricity Supply Industry
ESKOM	Electricity Supply Commission of South Africa
FGD	Flue Gas Desulfurization
FOB	Free on Board
FPS	Floating Plant System
FSRU	Floating Storage & Regasification Unit
GHG	Greenhouse gases
GT	Gas Turbine
HFO	Heavy Fuel Oil
HPP	Hydroelectric Power Plant
HRSG	Heat Recovery Steam Generator
ICRE	Internal Combustion Reciprocating Engine
IDC	Interest During Construction
INDC	Intended Nationally Determined Contributions
IPP	Independent Power Producer
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
LRMC	Long-run Marginal Cost
MME	Ministry of Mines and Energy
MSB	Modified Single Buyer
MSW	Municipal Solid Waste
MW	Megawatt, i.e. One Million Watts
N$	Namibian Dollar
NG	Natural Gas
NIRP	National Integrated Resource Plan
OPE	Oshakati Premier Electric

PC	Pulverised Coal
PPA	Power Purchase Agreement
PV	Solar Photovoltaic
RE	Reciprocating Engine
RED	Regional Electricity Distributor
SAPP	Southern African Power Pool
TOR	Terms of Reference
UNFCCC	United Nations Framework Convention on Climate Change
US$	United States of America Dollar
USTDA	US Trade and Development Agency
WB	The World Bank
WTE	Waste to Energy
ZESC	Zambia Electricity Supply Corporation Ltd.
ZPC	Zimbabwe Power Company

1. Background

1.1 Introduction

This report is the Final Report prepared as the fifth and final deliverable under Hatch Ltd.'s (Hatch) contract with the Electricity Control Board (ECB) for Consultancy Services on Review and Update of the National Integrated Resource Plan (NIRP) for Namibia (NIRP Update). The NIRP is a 20-year development plan for Namibia's Electricity Supply Industry, spanning the period between 2016 and 2035. The report provides the context for the NIRP Update, outlines the existing electricity supply facilities, describes the parameters used in preparing the NIRP Update, presents the load forecast, summarises the generation resources and options included in the analysis, outlines the analysis carried out to determine the preferred generation options and puts forward the recommended National Integrated Resource Plan along with an implementation plan.

In carrying out this assignment Hatch was supported by the Namibian consulting firms EMCON Consulting Group and VO Consulting.

1.2 Scope of Work

The scope of work for the project is provided in the ECB's Terms of Reference which are included as Annexure A to the contract between the ECB and Hatch. For easy reference, these Terms of Reference are provided in Appendix A of this report.

1.3 Timeframe for the Project

The contract for this project was signed on October 23, 2015. The Inception Mission took place during the period October 19 through October 28, 2015. The first one-week training workshop was presented at the end of November and the first Stakeholder Workshop was held on December 2, 2015. A Progress Report was submitted on January 7, 2016 and a Preliminary Draft Final report was submitted on February 19, 2016. The latter report formed the basis of the presentation given at the second Stakeholder Workshop held on March 2, 2016. The second one-week training workshop was presented in early March. The Draft Final Report for the study was issued on March 31, 2016. This Final Report includes responses to the ECB and stakeholder comments that have been received on the Stakeholder Workshop presentation and the Draft Final Report. A companion summary report has also been prepared that focuses on the Plan for implementation of the NIRP.

1.4 Data Collection

Data collection has proceeded through two main channels – 1) meetings with and/or data requests to ESI agencies and, 2) collection of reports and other documents.

The ECB prepared an official letter signed by its CEO introducing the project consultants and requesting ESI agencies to engage in the project and be available to meet with and provide the required data to the Consultant (see Appendix B).

At the start of the Inception Mission, Hatch provided its overall data requirements list to the ECB. This list is also provided in Appendix B. This list was used as the basis for the preparation of specific listings and templates which were then distributed to the relevant ESI agencies.

Given their locations across the country, a survey was judged to be the most expeditious approach for initial data collection from distributors. This survey questionnaire is also included in Appendix B.

Table 1-1 lists the documents that have been collected to date.

Table 1-1: Reports and Other Documents Collected

No.	Description	Published by	Date
1	Annual Report	Electricity Control Board	2015
2	Electricity Supply Industry – Statistical Bulletin	Electricity Control Board	2014/15
3	Terms of Reference – Consultancy Services for the Review and Update of Namibia's IPP and Investment Market Framework	Electricity Control Board	July 2015
4	Terms of Reference for Procurement of Consultancy Services to Develop a Renewable Energy Policy for Namibia	Electricity Control Board	August 2015
5	Tender for Namibian Consultant to Support the Energy Policy Committee to Review and Update the White Paper on Energy Policy	Electricity Control Board	September 2015
6	Annual Report	NamPower	2015
7	Demand Side Management – Progress Report	NamPower	October 2015
8	REFIT Power Purchase Agreement Template – Solar PV	NamPower	n/av
9	REFIT Power Purchase Agreement Template – Wind	NamPower	n/av
10	REFIT Power Purchase Agreement Template – CSP	NamPower	n/av
11	REFIT Power Purchase Agreement Template – Biomass	NamPower	n/av
12	REFIT Transmission Connection Agreement	NamPower	n/av
13	White Paper on Energy Policy	Ministry of Mines and Energy	1998
14	Namibia Vision 2030	Office of the President	2004
15	Namibia Household Income & Expenditure Survey	Namibia Statistics Agency	2012
16	Energy Demand and Forecasting in Namibia	Office of the President	2013
17	Renewable Energy Feed-in Tariff Rules	Nexant	August 2014
18	Annual Review	Chamber of Mines	2014
19	Mines in the Pipeline & Non Chamber Members	Chamber of Mines	October 2015
20	Newsletter	Chamber of Mines	August 2015
21	Commodity Markets Outlook	World Bank	October 2015
22	Harvesting Namibian Encroacher Bush	GIZ GmbH	2015
23	WattsOn	NamPower Newsletter	Edition #1 2015
24	Intended Nationally Determined	Government of Namibia	September

No.	Description	Published by	Date
	Contributions		2015
25	Eskom Schedule of Standard Prices 2015/16	Eskom	April 2015
26	SAPP Generation Planning Criteria	SAPP	November 2011
27	Commodity Markets Outlook – Quarterly Report	WB	April 2016
28	Annual Energy Outlook 2015	EIA	April 2015

1.5 Outline of the Report

This report is presented sequentially in 8 sections and 3 appendices.

Section 1 provides background information on the scope and timing for the project as well as the data collection program. Section 2 provides a brief overview of the existing Namibian electricity sector and indicates the context for the NIRP within the various activities required for a successful electricity supply industry (ESI). Section 3 presents the parameters that will be used in the preparation of the NIRP Update. Section 4 identifies the generation options that will be considered and outlines the key data that will be used for each in the technical/economic analysis. Section 5 provides the updated load forecast for the study period and the supply-demand balances for the initial years of the study period. Section 6 presents the formulation of the expansion scenarios and Section 7 provides the basis for selecting the preferred scenarios based on alternative national policies. Section 8 provides the implementation plan for the NIRP.

Turning to the appendices, Appendix A provides the contract statement of work. Appendix B provides the ECB's letter introducing the consultants and requesting the cooperation of stakeholders in providing data and information for the project, Hatch's data request list and a copy of the survey questionnaire sent to electricity distributors. Appendix C provides schedules of unit/plant additions/retirements for a number of the expansion scenarios analyzed in preparing this updated NIRP.

2. Context for the NIRP Update

2.1 Introduction

This section provides an overview of the Namibian ESI and indicates where the NIRP fits within the various activities carried out in the development of the sector. Following this, the characteristics of the existing power supply and delivery assets are outlined.

2.2 The Namibian ESI and the Role of the NIRP

Namibia has a well-developed ESI that has many features in common with best practices around the world for ESIs. Figure 2-1 identifies the agencies that make up the ESI and depicts how these agencies combine to supply electricity consumers with the services they require.

As the national power company fully owned by the Government of Namibia, NamPower has played, and continues to play, many roles in the ESI. Included amongst the roles played by NamPower has been the single buyer role in which it has been responsible for power import/export agreements with neighbouring countries as well as the purchase of power generated by any Independent Power Producers (IPPs) operating within Namibia. Current developments in the ESI see the role of IPPs increasing. NamPower has recently signed Power Purchase Agreements (PPAs) with a number of individual companies that plan to develop some 70 MW of renewable power projects. Additional IPP generation projects are in the pipeline.

At the same time, a modified single buyer (MSB) model has been proposed with the intent of allowing IPPs to sell power directly to distributors and large users. It is understood that implementation of the MSB model is ongoing.

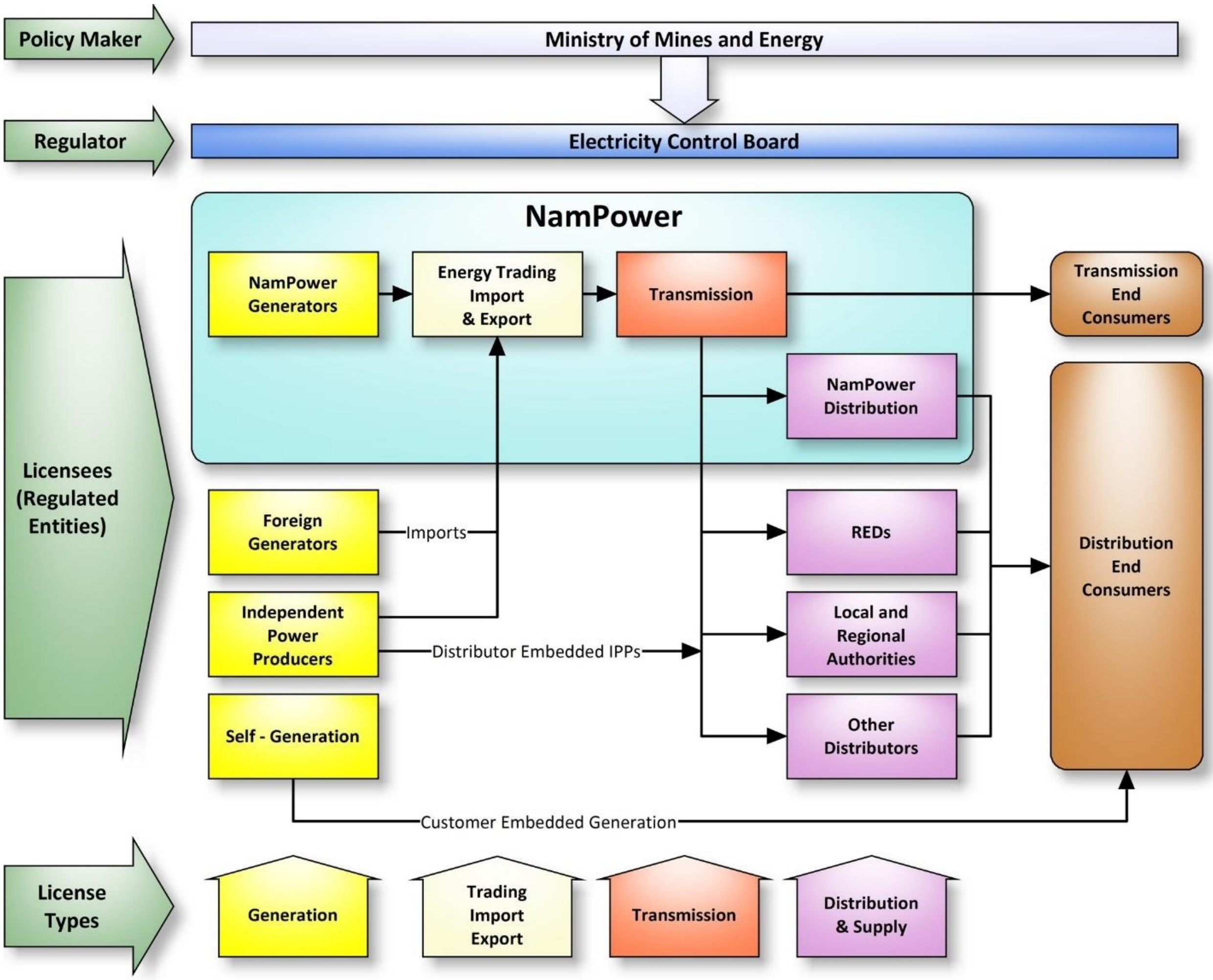

Figure 2-1: ESI in Namibia

Following on from the overall structure of the ESI as shown in Figure 2-1, it is important to note the overall context for the NIRP, in particular the key inputs to the NIRP and the ways that the NIRP would be used in the ongoing development of the sector. Figure 2-2, in which the NIRP is highlighted in green, is designed to convey this information.

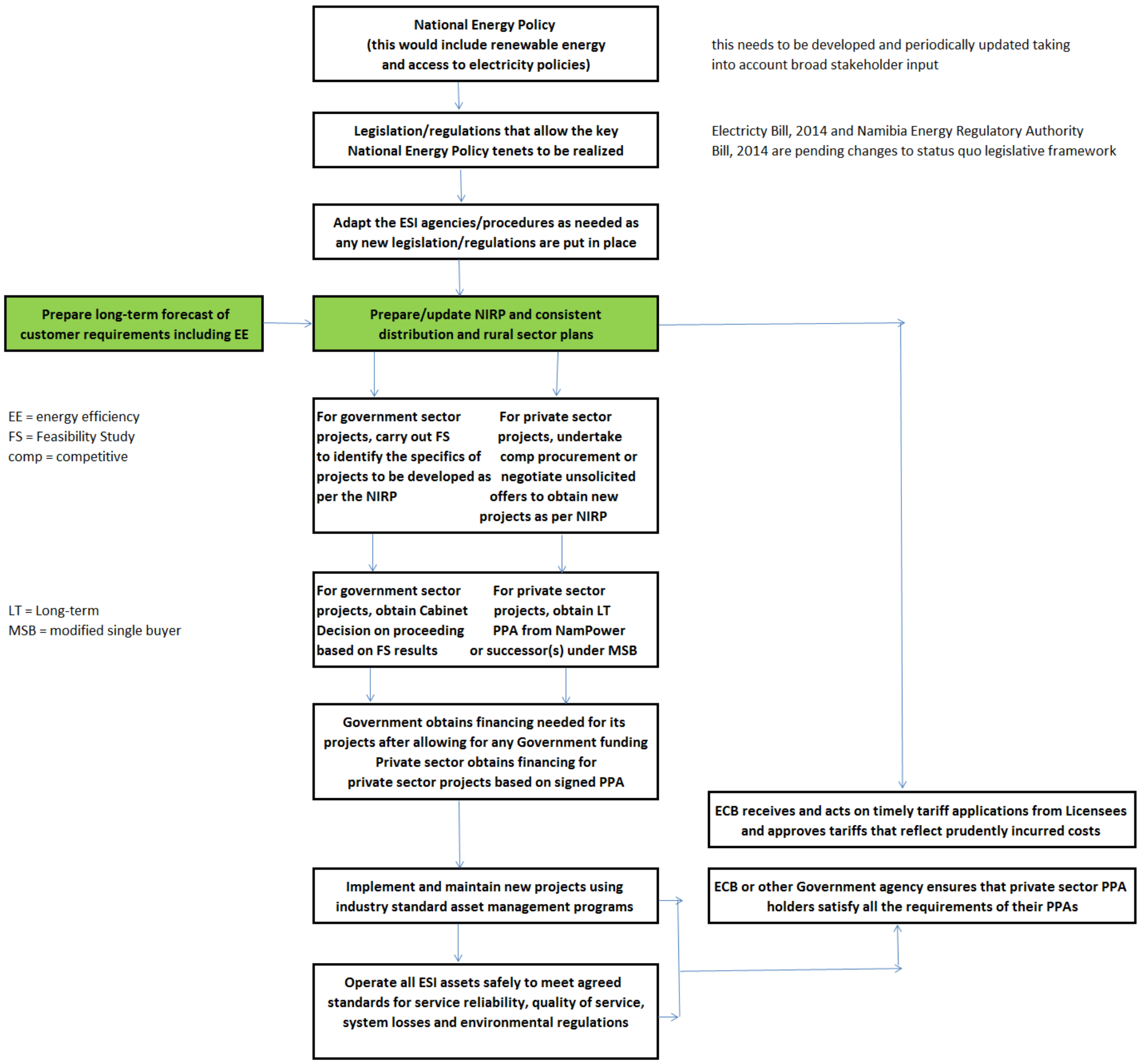

Figure 2-2: Context for the NIRP

As indicated in the chart, national energy policies should set the stage for all aspects of the ESI. At the present time, the White Paper on Energy Policy of 1998 is the key policy document for the ESI. The ECB is currently undertaking three very important policy reviews that will have important implications for the ESI. The first is the review and update of the White Paper itself. At the same time, the ECB is developing the country's first Renewable Energy Policy and is also carrying out a review and update of Namibia's IPP and Investment Market Framework. These initiatives will potentially have significant impacts on the ESI and in turn on future NIRPs. The current review and update of the NIRP will be informed by these initiatives but due to the timing of the current study will likely not reflect the final outcomes of the three policy initiatives.

2.3 The Namibia Power System

2.3.1 Inventory of Existing Power Plants

Summary

Table 2-1 provides summary information on the existing grid connected commercial power plants.

Table 2-1: Power Plants in Namibia January 2016

Plant Name and Type	Installed Capacity - MW	Current Maximum Net Output - MW	Upgrades Underway extra MW	Upgrades Underway Complete	Planned Retirement
Ruacana - hydro	332	332	15	2016	TBD
Van Eck - coal	120	60	21	2016	2025
Paratus - LFO/HFO	24	6			2018
Anixas - LFO/HFO	22.5	21.5			TBD
Innosun - solar PV	4.5	4.3			TBD
HopSol - solar PV	5	5			TBD
	508	428.8	36		

Ruacana Hydropower Station

The Ruacana hydro power station is located on the Kunene River, in the north of Namibia, where the Kunene River becomes the border between Namibia and Angola. The station was commissioned in 1978 and consists of three 80 MW hydro generators and a fourth unit of 92 MW commissioned in May 2012 for a total capacity of 332 MW. The station has black start up diesel generators and a 330 kV transmission line running from Ruacana to the Omburu substation which is some 570 km in length.

The Ruacana station is mainly operated as a run-of-river power plant as its upstream storage dams are either not completed or were damaged in the Angolan civil war. The output of the hydro power station depends on the amount of water available in the river. A small diversion weir just upstream of Ruacana allows the power station to produce at its full capacity for eight hours. During the rainy season (from February to May) the station is run at full output level and operated as a base load power plant, while for the remainder of the year it is operated predominately as a peaking power plant.

NamPower has identified the need to repair the runners in the turbines of units 1 to 3. Since the repair of the runner structure is required, NamPower has considered a major refurbishment of the turbines including replacing runners with more efficient design. This refurbishment will increase efficiency by approximately 6% for each unit. This increase will provide approximately 5 MW of additional peaking capacity per unit. In addition, on average, the plant’s generation will increase by about 60 GWh on an annual basis. Once the refurbishment is completed, the maximum plant output will be approximately 347 MW (3x85 + 92).

The monthly energy production for Ruacana, once the refurbishment is completed, is shown in Table 2-2 for average and firm conditions. In this case “firm” energy is that energy that is associated with a hydrology of 90% probability of exceedance. While a 95% probability level of exceedance is often used in planning work to allow for a reliable supply level in case that a dry hydrology is encountered during any particular year, the 90% level was selected for this study due to the existing interconnections of the Namibian network with other networks in the region.

Table 2-2: Ruacana Generating Capability

Month	Firm Energy (GWh)	Average Energy (GWh)
January	90.74	148.44
February	101.49	166.03
March	142.35	232.86
April	139.19	227.69
May	120.42	197.00
June	69.82	114.22
July	57.74	94.45
August	45.36	74.21
September	35.92	58.77
October	27.27	44.61
November	32.45	53.09
December	57.24	93.64
Total	**920.0**	**1,505.0**

For planning purposes and in order to construct a system model, the plant will be modelled with a forced outage rate of 4% and planned maintenance of 2 weeks per year for each unit will be modeled by derating monthly capacities over the months with energy limitations.

Van Eck Coal Power Plant

The Van Eck coal-fired power plant is situated on the northern outskirts of Windhoek. It has a total rating of 120 MW using four 30 MW generators and was commissioned in 1973. Due to various reasons, only up to three units can currently be operated at the same time. The station needs external power for start-up. Due to the frequent water constraints in Windhoek the plant was designed as a dry cooled station. The coal used is imported from South Africa, transported by ship to Walvis Bay and then by rail or road to Windhoek. This is costly and the plant is normally operated as a standby and peaking power station only. During the recent regional constraints, it has been run at mid-merit to base load. The power station has very limited emission control equipment and thus emits high levels of air pollutants. The station is therefore limited to burning 3,500 tonnes of coal each week, although it may use emergency stockpiles if necessary.

These aging units are becoming less and less reliable as they approach the end of their technical life. At present, the maximum continuous output of the plant can reach is only some 60 MW due to various constraints.

A study on the rehabilitation options for the plant funded by the US Trade and Development Agency (USTDA) was completed a few years ago. The study examined several rehabilitation options which would result in different output, extension of life and capital costs.

As per the information collected, refurbishment of the Van Eck Power Plant started a few years ago and it is expected the refurbishment will be completed by early 2016. After the rehabilitation work, it is expected that the plant would meet its original design output of 120 MW (gross) and will be able to achieve a guaranteed base load output of at least 90 (gross) MW. Table 2-3 presents the expected main parameters of the plant after refurbishment, to be used in the NIRP Update study.

Table 2-3: Characteristics of the Van Eck Coal Power Plant

Item	Refurbished
Net Capacity (MW)	108
FOR (%)	10
Planned Maintenance	42 Days
Net Heat Rate (kJ/kWh)	17,569
Fixed O&M (N$/kW-Yr)	2,200
Variable O&M (N$/MWh)	In the Fixed O&M

Anixas Power Station

The Anixas power station is located near the Paratus power station in Walvis Bay. This station benefits from new and proven technology which has a higher efficiency and reliability, and less emissions and noise than older power stations of its type. There are 3 Caterpillar V16 cylinder internal combustion reciprocating engines (ICRE) generator sets, each with a net electrical capacity of 7.5 MW, for a total of 22.5 MW (gross). The power station started operations at the end of July, 2011 with the official inauguration in November 2011.

The three generator sets are housed in a building with its own control room, offices and a black start generator of 810 kVA capacity. The generators use LFO for starting and stopping and HFO once they have reached a certain output. The station has fuel offloading facilities and a fuel treatment system.

Radiators are used for cooling. A high exhaust stack disperses emissions high up, reducing ambient concentration of any pollutants. Noise attenuation and control conform to international standards. Care was also taken to select materials capable of withstanding the extreme corrosive environment of Walvis Bay.

Table 2-4 presents the characteristics for the generating units at Walvis Bay.

Paratus Power Station

The Paratus power station is located in Walvis Bay. It has a total rating of 24 MW using four 6 MW (nominal) ICRE generators The rating of each unit is dependent on the ambient temperature, with a rating of approximately 5 MW at low temperatures and some 2 MW at high temperatures. The station has a black start up generator and was commissioned in 1976. It is used mainly as a standby and peaking power station respectively but it is also contractually bound as an emergency standby plant for the city of Walvis Bay. Paratus runs at very high marginal cost and can only generate a maximum of 6 MW (gross).

The power station uses light fuel oil (LFO) to start-up and shut down, switching to heavy fuel oil (HFO) once a unit is generating more than 2.7 MW.

NamPower expects to retire the Paratus power station by the end of 2017 and advised that the site may be used to construct a 4X10 MW RE power plant, which could be commissioned by the end of 2018. Table 2-4 presents the characteristics for the existing units at Paratus.

Table 2-4: Characteristics of the Walvis Bay Diesel Plants

Item	Anixas	Paratus
Net Sent Capacity (MW)	21.5	6.3
FOR (%)	5.0	18.0
Planned Maintenance	3 weeks/unit	4 weeks/unit
Net Heat Rate (kJ/kWh)	9,040	19,194
Fixed O&M (N$/kW-Yr)	705	3,292
Variable O&M (N$/MWh)	Included in Fixed O&M	Included in Fixed O&M

2.3.2 Power Import Agreements

Imports continue to account for a large proportion of the electricity requirements in Namibia. According to the ECB's Electricity Supply Industry Statistical Bulletin 2014/15, of the approximately 4,400 GWh sourced in FY 2014, some 2,900 GWh (approximately 66% of the total) were brought into the Namibian grid from external sources. These imports were obtained from several electricity markets as summarised in Table 2-5 and described in more detail below.

Table 2-5: Summary of Namibia's Power Import Sources

Supplier	Maximum Supply - MW	Capacity Factor - %	Expiry Date
ESKOM -Supplemental	200	20	Annual
ESKOM - Off Peak Bilateral	300	50	31/03/2017
ZESCO – Zambia	50	100	31/12/2020
ZPC – Zimbabwe	80	50	31/03/2025
Aggreko - Mozambique	110	N/A	31/12/2015
Total	740		

Imports from South Africa

There are two contracts in place between NamPower and Eskom, the Bilateral contract and the Supplemental contract. The former could be renewed on an annual basis and the latter will expire on March 31, 2017. It is noted that the Bilateral contract may also be renegotiated and/or renewed.

The imports associated with the Bilateral contract can only be used during off peak periods which are defined by Time of Use schedule. There is no capacity charge on the import and energy prices are specified by season (high and low demand seasons) and time period (Peak, Standard and Off-Peak). The weighted price to be used for the Bilateral contract is N$ 627.1/MWh.

A supply contract with up to 200 MW of Special Assistance or the Supplemental contract was negotiated with Eskom with the provision that it will be reviewed annually. Due to power supply shortages within South Africa, this supply option can only be requested by NamPower after all local supply options have been exhausted, including any active demand management programs within Namibia. There is no capacity charge on the import and energy prices are specified by season (high and low demand seasons) and time period (Peak, Standard and Off-Peak).

Based on the contract clauses, NamPower must also shed its load if there is load shedding in South Africa due to generation shortages. The load to be curtailed in Namibia is equal to the Eskom load shedding ratio multiplied by the amount of Special Assistance.

This agreement is vital to Namibia's security of supply as depicted given the percentage of Eskom's share of the total imports over the last few years.

The tariffs associated with this contract are complex and require intelligent meters to be in place to accurately record the power that is imported. For the present study the model to be used is unable to correctly model the complexity of seasonal and three daily tariffs and as such it was decided to blend the tariffs into a single value taking into account the duration of each time of use value. The price actually paid is heavily dependent on the number of hours of imports during each time period the foreign currency exchange rate as the prices are based on US$. Under the agreement with Eskom, the lower the number of hours of import during the off peak period, the higher the blended price. The weighted price to be used for the Supplemental contract is N$ 2,782.3/MWh.

Power Supply Agreement with Zambia

The power supply agreement with the Zambia Electricity Supply Corporation Limited (ZESCO) came into effect on 16 January 2010. The agreement has a 10-year duration and a firm capacity of 50 MW, which will be expiring on December 31, 2020.

There is also a non-firm agreement with ZESCO for 50 MW which would be confirmed on a daily basis but this agreement has not been executed. This could be partially due to transmission constraints in the ZESCO system and could be executed once the constraints are resolved.

The ZESCO import has a two-part tariff, a demand charge and an energy charge. The import has a very high capacity factor and has been identified as being close to 100%. The capacity charge has to be paid regardless of the amount of energy being withdrawn. At 100% capacity factor the blended cost of energy will be N$712.8/MWh.

Power Supply Agreement with Zimbabwe

NamPower has a power supply agreement with the Zimbabwe Electricity Supply Authority (ZESA) for the supply of 80 MW. The contract will expire on March 31, 2025. The weighted tariff for this contract is N$ 2,224/MWh.

Power Supply Agreement with Aggreko in Mozambique

This agreement for up to 110 MW expired on December 31, 2015.

2.3.3 Transmission and Distribution Systems

As shown in Figure 2-3, the Namibian transmission system extends from Ruacana close to the Angolan border in the North to the border of the Republic of South Africa in the South, where it joins with the ESKOM interconnected grid. In the North, the system also reaches the

Zambezi Region where it borders with the Zambian system. In the East the system extends to the border of Botswana.

The NamPower transmission backbone consists of transmission running at 330 kV from the Ruacana power station to the Omburu substation and from there at 220 kV to the South Africa border for a total length of 1,518 km. There is a 220 kV transmission ring connecting the Van Eck power station to Kuiseb (Walvis Bay is supplied at 66 kV, being upgraded to 132kV) with the link between Van Eck and Omburu having two 220 kV transmission lines.

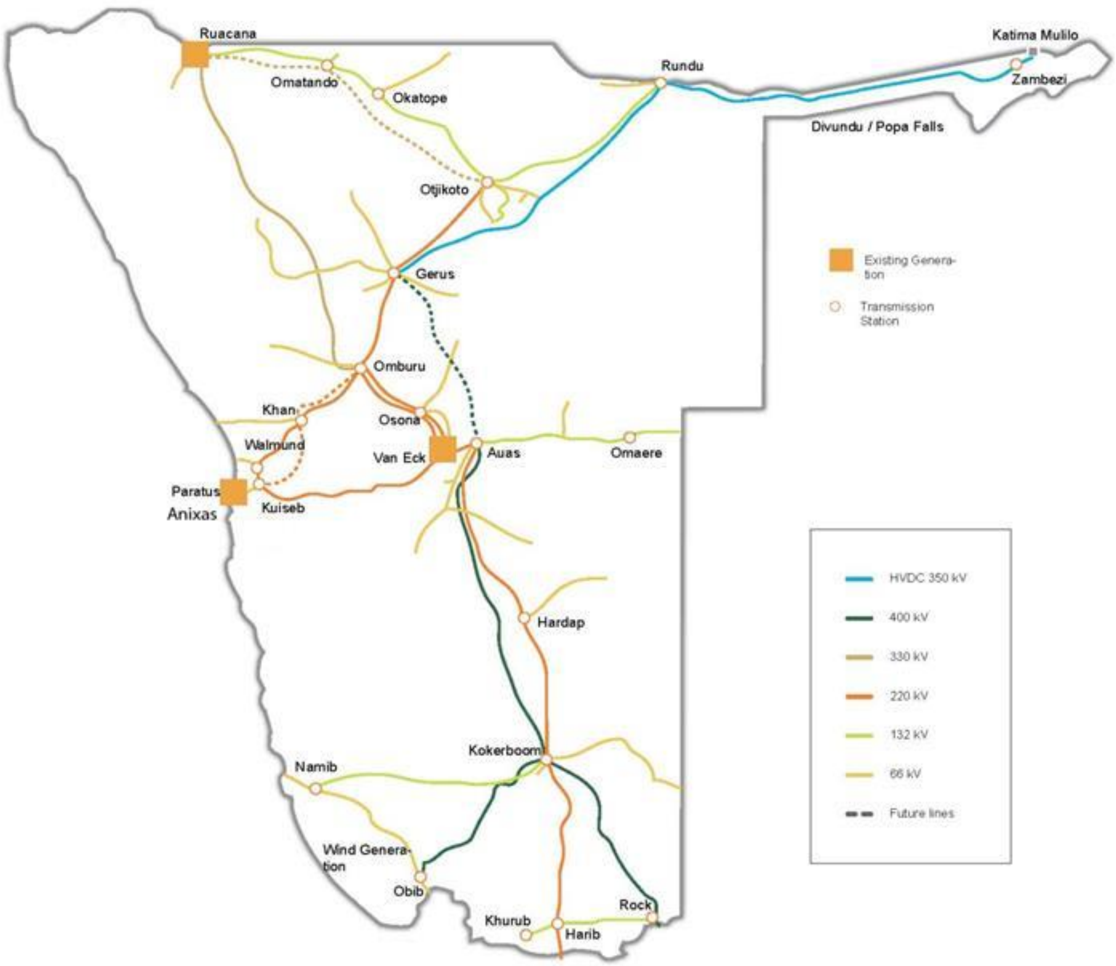

Figure 2-3: Transmission System of Namibia

The transmission system consists of several transmission voltages including 66 kV, 132 kV, 220 kV, 330 kV and 400 kV as well as 350 kV HVDC.

The first stage of the Caprivi Link Interconnection project was officially commissioned on November 12, 2010, which comprises a 951 km 350 kV HVDC line with converter stations at Zambezi and Gerus substations. The Zambezi substation is located in Katima Mulilo, the Capital of the Caprivi Strip at the border between Namibia and Zambia. The Gerus substation is situated outside Otjiwarongo in central Namibia.

The Caprivi Link Interconnection was built in monopole mode with capability of transmitting 300 MW of power. It could be upgraded to 600 MW in bi-pole mode as demand increases and as trading opportunities evolve in the region. The link is an important component of the future ZIZABONA connection.

ZESA of Zimbabwe, ZESCO of Zambia, BPC of Botswana and NamPower of Namibia signed an Inter-Utility Memorandum of Understanding (IUMOU) for co-operation in new transmission infrastructure investment. The project is planned to be commissioned in two phases, namely the Hwange/Livingstone (Phase 1) and Victoria Falls – Pandamatenga – Zambezi Transmission Stations (Phase 2). Due to challenges encountered with regards to the financing of the ZIZABONA Project, it was decided to engage a consultant to repackage the project. The scope of the consultant is to conduct market studies, transmission pricing and system studies in support of the realisation of the project.

Distribution lines with the voltage 33 kV and below extend radially from the main substations for further dispersion of power to the consumption areas along the coast and inland. As great parts of the country are rather sparsely populated, the area served by the distribution network covers quite a small portion of the total area.

The REDs and certain local and regional authorities are responsible for the distribution and supply of electricity to end consumers within their respective areas. As of the end of the 2014/2015 fiscal year they serve approximately 233,000 end consumers, of which some 90% are domestic users.

2.4 Committed Power Plants

There are several power generation projects which could be treated as committed power plants. These are summarised in Table 2-6.

Table 2-6: Committed Power Plants as of January 2016

Project	MW	Notes
REFIT	70	PPAs signed, up to 6 months for financial close
NP Solar	37	currently in bidding stage
GreeNam solar	20	PPA signed
Diaz Wind	44	PPA signed
Total	171	

The 70 MW REFIT program includes 14 individual projects, each at 5 MW. Only one of the 14 projects will be from wind and the rest will be from solar PV.

3. Study Parameters

This section provides the economic parameters on which the NIRP Update analysis will be based, defines the power system reliability criteria that will be used and outlines the assumptions on fuel prices.

3.1 Economic Parameters

3.1.1 National Focus

The development of the NIRP Update is carried out from a national perspective to maximise the benefits to all Namibians rather than being concerned with particular interests of individuals or entities. The NIRP Update is to cover the entire territory of Namibia and take into account existing policies and the national development strategy of Vision 2030.

3.1.2 National Focus and White Paper on Energy Policy

The Namibia Energy Policy Committee (NEPC) of MME published the White Paper on Energy Policy in May 1998. It is noted that the ECB has recently tendered for selection of a consultant to assist the Energy Policy Committee review and update the 1998 White Paper. However, the updated policy is not expected to be prepared and approved in time for reference as part of this work on the NIRP Update.

The 1998 White Paper is quite a comprehensive document consisting of an executive summary and five principal sections. Section 1 provides the rationale for the White Paper on Energy Policy and the sector's profile, Section 2 focuses on energy demand for the productive sectors, urban energy needs and rural energy needs. Section 3 addresses energy supply and deals with electricity, gas, liquid fuels and renewable energy. Section 4 deals with cross cutting themes including economic empowerment, environment, health and safety, energy efficiency and conservation and regional energy trade. Section 5 points to the way forward.

The following goals served as a framework for the energy policies;

- ***Effective governance -*** Systems were to be in place to provide stable policy, legislative and regulatory frameworks for the sector.
- ***Security of supply –*** To be achieved through an appropriate diversity of competitive and reliable sources, with emphasis on the development of local resources.
- ***Social upliftment –*** Consumers to have access to appropriate, affordable energy supplies.
- ***Investment and growth -*** The sector to expand through local and foreign fixed investment, resulting in economic benefits for the country. Attention to be given to black economic empowerment.
- ***Economic competitiveness and efficiency -*** The sector to be economically efficient and to contribute to Namibia's economic competitiveness.
- ***Sustainability -*** The sector to move towards the sustainable use of natural resources for energy production and consumption.

As part of the energy policy, Government is to promote the use of renewable energy through the establishment of an adequate institutional and planning framework, the development of human resources and public awareness and suitable financing systems.

The energy policy goal of sustainability is to be promoted through a requirement for environmental impact assessments and project evaluation methodologies which incorporate environmental externalities. While energy efficiency was to be promoted through policies on better information collection and dissemination, and particularly with respect to energy efficiency and conservation practices in households, buildings, transport and industry. Security of supply was to be achieved through an appropriate diversification of economically competitive and reliable sources, but with particular emphasis on Namibian resources.

As part of one of the policy statements, the White Paper on Energy Policy outlines the amounts of generation to be from internal sources stating: “Duly considering associated risks, it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand will be supplied from internal sources by 2010. Risk mitigation measures will be pursued, including the possibility of regional equity participation in, and guarantees for, Namibian generation projects.”

As of the time of writing, the targets for internal supply specified in the policy have not been realised. Generation resources located within Namibia’s territory can currently supply up to a maximum of 420 MW (even though the installed capacity is now approximately 500 MW) to meet a peak demand that has reached 597 MW (in June 2015); imports from sources outside Namibia have provided an average of just over 60% of the annual energy requirements over the last five years.

3.1.3 Economic Costs

The NIRP Update is prepared from a national perspective using economic costs rather than financial costs. As shown in Figure 2-2, financial factors come into play when specific projects in-line with the NIRP Update are developed by government, the private sector or by means of public private partnerships. The NIRP Update analysis is based on economic values that do not take into account such factors as the imposition of taxes or royalties by government or any risk premium that may be charged by private sector investors. Government taxes and royalties are not included in the calculation of economic costs, as these are a transfer payment between one group in the economy and another, rather than a cost to the economy as a whole. The analysis is carried out using a social discount rate, that is, the rate of return on capital expected by society, rather than the investment criteria that may be used by the private sector.

Economic costs are used to determine what the right choices would be from the point of view of the Namibian economy and society as a whole.

3.1.4 Planning Horizon

As per the requirement outlined in the Terms of Reference, the plan is to cover a development period of 20 years and it is intended to model the system from 2016 to 2035.

At the end of the simulation period, the various expansion scenarios can have different plant mixes with different remaining lives and different operation and maintenance costs as well as different investment costs. In order to measure all benefits of the plants that are commissioned in the planning period and take into account different plant lives, it is a common practice in integrated resource planning to extend the planning horizon by a period ranging from 10 to 15 or more years. For the extended period, demand and supply are maintained at the same level as at the end of the simulation period. An extended period of 15 years is used in this study.

In order to simplify the overall analysis and for ease of understanding the overall concept, the report will show the cumulative present worth of costs to the end of the 20-year planning period for each generation expansion scenario and the cumulative present worth of costs for the extended period.

3.1.5 Cost and Present Worth Datum

All costs will be expressed in January 2016 prices. All present worth and discounting calculations will also use January 2016 as their reference point.

3.1.6 Escalation

The economic analysis will be based on real costs expressed at January 2016 price levels, omitting projections for general price inflation during the planning period. However, if any parameters are expected to exhibit price changes that are significantly different than the rate of general price inflation, a differential escalation rate will be included.

3.1.7 Currency and Exchange Rate

All monetary values will be expressed in constant Namibian Dollars (N$), in border prices or equivalence. All economic costs and benefits will exclude all local duties and taxes. The Namibian Dollar is pegged at parity to the South African Rand thus a border price to South Africa would be equivalent to the Namibian border price with the addition of an appropriate transportation cost.

For this assignment, prices that are obtained in United States Dollars (US$) will be converted to N$ at an exchange rate of 1 US$ to 16 N$ although the exchange could fluctuate significantly. On December 11, 2015, one US$ was approximately equal to 15.8 South African Rand (ZAR), which is equivalent to N$. One recent forecast indicates that ZAR will be continuously devalued over next two years and one US$ could be equal to 17.5 ZAR by the middle of 2016.

3.1.8 Discount Rate

Typical practice for national economic studies is to set the discount rate at 10 percent. This rate is used in this study to calculate the present worth of input costs expressed in real terms.

The study will also consider discount rates of 6%, 8%, 12% and 14% as part of the sensitivity analysis.

3.1.9 Cost of Expected Unsupplied Energy

A customer survey of the market sectors of the ESI in South Africa indicated that the cost of unserved energy could be in the order of 20,000 N$/MWh. Recent surveys in South Africa have suggested even higher values, as high as 75,000 N$/MWh.

An economic expression for the cost of unserved energy is to divide the country's GDP by the total electricity consumption. Considering Namibia's GDP of N$ 141 billion (for 2014 in current prices) and electricity generation plus imports of some 4,400 GWh (in 2014) this would result in a value of about 32,000 N$/MWh.

Based on this information, a value of 30,000 N$/MWh or 30 N$/kWh will be used for the cost of unserved energy in this NIRP Update.

3.1.10 Cost of Losses

To evaluate the different transmission expansion plans it will be necessary to compare and cost losses between the different plans. The energy value of losses will be based on the most expensive cost of energy import, while capacity losses will be evaluated based on the cost of gas turbines.

3.1.11 Duties and Taxes

Duties and taxes are not included in this economic study.

3.1.12 Interest During Construction

Interest is a financial cost and as such is excluded from the economic evaluations. The impact of construction periods of different lengths will be taken into account by distributing the capital over the entire construction period. In order to align the distributed investment flow and present value calculation, the rate used will be equal to the discount rate.

3.2 Reliability Criteria

The primary objective of generation expansion planning is to find the least cost long-term expansion scenario that supplies the forecast demand at an acceptable or specified level of reliability. In any given year it is essential to verify that the generation capacity reserve is sufficient so that the system can meet the load demand even if one or more units are out of service and/or, for systems with significant hydroelectric capacity, unexpected hydrological conditions are encountered. The reliability criteria are usually the deciding factor in scheduling the addition of new generating plants. There are usually two types of reliability criteria used in generation expansion planning: deterministic and probabilistic.

3.2.1 Deterministic Criteria

There are a number of ways to define deterministic reliability criteria. The core part of these criteria is, however, generation capacity. Depending on the application, these criteria could be measured using the values calculated using generator gross MCR (maximum continuous rating), net MCR (gross MCR less station services), or seasonal MCR (MCR less seasonal derating and/or energy limitation). Some utilities/systems apply the deterministic criteria prior to allowing for generating unit planned maintenance outage while others apply them after.

The deterministic reliability criteria are normally expressed in three different ways: (1) a fixed amount of capacity in MW to account for the random outage of one, two or more largest units, (2) a percentage of annual peak demand, or (3) a percentage of annual peak demand plus a fixed amount of capacity.

3.2.2 Probabilistic Criteria

The probabilistic reliability criteria include both the loss of load probability (LOLP) and the expected unsupplied energy (EUE), which are obtained from the convolution of the load demand and available generation.

LOLP is used to measure the risk associated with having insufficient generation capacity to meet the forecast load demand, which is normally expressed in days per year or hours per year, or as a percentage. For example, a 1% LOLP indicates that the installed generation will not be able to meet the forecast demand in a given year for 3.65 days or 87.6 hours. It is important to understand that a simple LOLP value may have different implications as it could be calculated based on either a daily peak load duration curve or an hourly load duration curve. In the case of the daily peak load duration curve, each day is represented by one point, the highest hourly demand during the day.

EUE is the quantity of expected energy that a system would not be able to serve with the planned generation system in a given year. It is expressed either in MWh or as a percentage in which case it is equal to the expected unsupplied energy divided by the annual energy demand and multiplied by 100.

In this study, a LOLP criterion value of 5 days per year was adopted for the period from 2016 to 2020 and 2 days per year for the balance of the study horizon, which allocates adequate time to achieve the reliability goal. The EUE criterion has been used as companion criteria with EUE not to exceed a value of 1%.

3.2.3 Southern African Power Pool (SAPP) Reliability Criterion

As a member of SAPP, Namibia is required to operate its power sector within parameters established by SAPP which include a reliability criterion. The SAPP reliability criterion is that the reserve capacity obligation of a member for any given period is to be equal to 10.6 % of the annual system peak of such member when the generating plant is thermal and 7.6 % when the generating plant is hydro. A weighted average is to apply to members who have a mixed system which implies an overall reserve of less than 10% for Namibia.

The SAPP criterion is classified as a deterministic criterion and since a probabilistic criterion is used in developing this NIRP Update, checks will be carried out that the SAPP criterion is satisfied.

3.3 Emissions Criteria

The development of any power plant needs to take full account of the environmental impact of the plant irrespective of its location. Due consideration must be taken of both the indirect and direct environmental effects and, where appropriate, suitable mitigation measures should be put in place.

Environmental considerations for power plants are addressed in Section 6 of this report. One of the environmental considerations for the thermal plants is the expected levels of emissions from the stacks of those plants (sulphur dioxide, nitrous oxides, carbon dioxide and other greenhouse gases, particulate matter, etc.).

In today's practice it is common when comparing different forms of generation to apply an economic levy on thermal plants to take account of the cost to society of emissions that, while within the legal limits, do create costs that society as a whole must bear. This is normally done on the basis of the level of emissions such as CO_2, SO_2 and NO_x expected to be emitted by the relevant plant type. Some studies levy a cost in terms of US$ per tonne for the emissions to represent the societal cost for these emissions. This study includes a penalty of 60 N$ per tonne of emissions, representing a societal cost, levied against thermal options, which reflects the current low market prices on voluntary GHG reductions.

3.4 Fuel Prices

This section presents price assumptions in January 2016 US dollars for the fuels to be included in preparation of the NIRP Update. The fuels considered include diesel (light fuel oil – LFO), residual (heavy fuel oil – HFO), natural gas (NG), liquefied natural gas (LNG), coal, uranium, biomass and medium blend fuels. The prices of fuels are converted from their native and usually used units into US$/GJ and subsequently into N$/GJ.

3.4.1 Fuel Background in Namibia

Liquid fuels, mainly in the form of petrol and diesel, dominate the Namibian energy sector. As per the report prepared by the Government of Namibia[1], the energy from oil products consumed (liquid fuels) in 2010 was some 73% of all energy consumed. The second largest energy form was electricity, accounting for some 15% (it is noted that the use of biomass was not taken into account in the report). The oil industry is controlled by five private oil companies, although the price and distribution of fuel is regulated by government. All liquid fuels are imported.

In 2010, coal and coal products accounted for only some 2% of Namibia's net energy consumption. As Namibia does not have economically exploitable coal reserves, all coal, is imported.

Biomass is the main fuel of households in the North where much of the population resides.

Namibia has an excellent solar resource and good biomass resources as well as fair wind resources. It has yet to record a commercial oil discovery, but it is endowed with largely undeveloped energy resources in the form of hydro-power and natural gas (Kudu field) in addition to uranium.

Exploration licenses for offshore and onshore drilling have been granted to a few major companies. The exploration is for both oil and natural gas.

3.4.2 Underlying Assumptions

All liquid fuels used in Namibia are imported and obtained in the world market; therefore, for the NIRP Update the price for these fuels will follow closely international prices for crude oil. As such it was decided to investigate the publicly available forecasts for crude as they could provide a good indication of the most likely future price trends.

Similarly, the coal used in Namibia is also imported and as such new generation sources using this fuel would also have to obtain coal in the international markets for which there are a few long range price forecasts.

Finally, it was judged that the base case price forecast for the Kudu natural gas would follow closely the price of internationally traded liquefied natural gas. It was assumed that natural gas available in the international market would be a good proxy for the price of the Kudu gas and in this case the cost of re-gasification would have to be considered.

The forecast prices were collected from four well known institutions, the EIA (Energy Information Administration), WBG (World Bank Group), KPMG and Sproule.

[1] Energy Demand and Forecasting in Namibia – Energy for Economic Development, National Planning Commission, Office of the President, 2013.

The U.S. EIA collects, analyses, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

The WBG's engagement in the energy sector is aimed at supporting developing countries to secure the affordable, reliable and sustainable energy supply needed to end poverty and promote shared prosperity. The WBG acts as a knowledge hub for Sustainable Energy for All, leading numerous agencies in major collaborative projects to monitor and report on energy development outcomes.

The KPMG Global Energy Institute allows global industry experts to share knowledge, insights, collaborate and participate in timely and relevant issues facing the market. Its Global Energy network works with major organisations in a variety of energy related sectors to respond to business issues and trends.

Sproule is a diversified, world-wide petroleum consulting firm with 60 years of experience in all aspects of the energy sector throughout North America and the World.

The outlooks produced by each of the four institutions are recent and are dated as of:

1. The EIA Annual Energy Outlook 2015 with Projections to 2040 was released in April 2015
2. The WBG Commodity Markets Outlook was released in April 2016
3. The KPMG Coal Price and FX Consensus Forecasts June/July 2015 issue presents the coal price outlook for the period from 2015 to 2019
4. The Sproule forecast was released in September 2015

Given its broad perspective on commodity markets, it was decided to base the price forecasts for oil and coal on the World Bank projections. The Sproule forecast was taken into account in selection of the forecast for natural gas prices.

3.4.3 Crude Oil Forecast

Crude oil price forecasts were collected from three institutions, the EIA, WB and Sproule.

Figure 3-1 shows the forecast prices for crude oil over the next 11 years, i.e. from 2015 to 2025. The EIA price is for imported crude delivered to U.S. refiners. The WBG price is for the average spot price around the world and the Sproule price is for UK Brent crude oil.

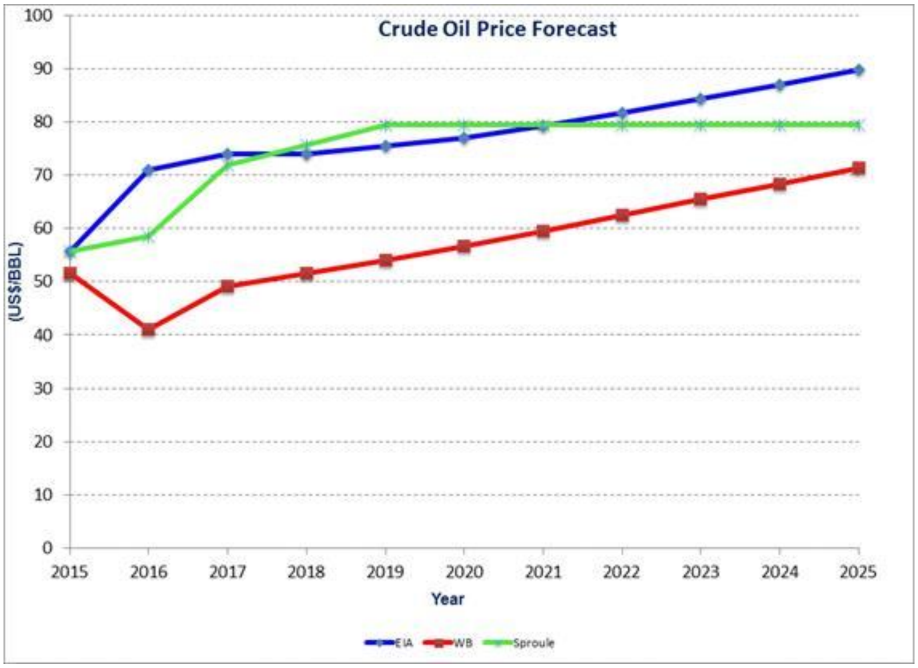

Figure 3-1: Crude Oil Price Forecast

The following could be observed from Figure 3-1:

1. The EIA forecast price is expected to increase over the forecast period, i.e. from the price of some US$ 54/BBL in 2015 to some US$ 88/BBL in 2025
2. The WB forecast predicts that the crude price would decrease to some US$ 40/BBL in 2016 and then increase to some US$ 70/BBL gradually from 2017 to 2025. It is noted that in December, 2015, the crude price was only approximately US$ 37/BBL
3. The Sproule forecast shows the price would be very close to US$ 80/BBL from 2019 to 2025
4. Based on the WB forecast, it was determined that an average price of US$ 60/BBL for crude oil will be used in this NIRP Update

It is important to note that the price forecasts shown in Figure 3-1 are the FOB prices and do not include the cost of transportation to the refinery, refining cost and delivery cost of the refined products to the end user.

To account for transportation, handling, refining, insurance and losses an additional cost of US$ 20/BBL will be added.

For forecasts beyond 2025, it is assumed that the trend for 2020 to 2025 would be followed from 2026 to 2034.

3.4.4 Price Forecast for Kudu Natural Gas

The forecast prices for natural gas were collected from the EIA, WBG and Sproule. As previously mentioned, it is assumed that these forecasts would serve as a proxy for the expected prices for the Kudu natural gas. Figure 3-2 shows two groups of forecasted prices, for Henry Hub (U.S.) and Europe. It can be seen from this figure that the Henry Hub prices are much lower than the European prices. The WBG predicted an almost constant price for the European gas. For Britain, Sproule forecasts a price increase over the next couple of years and after that the price will be relatively constant.

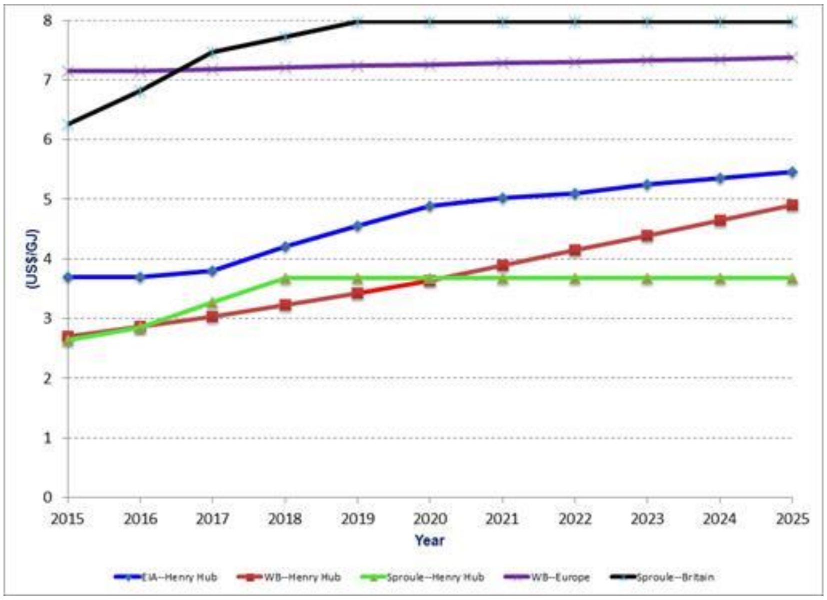

Figure 3-2: Natural Gas Price Forecast

In view of the above values it is difficult to forecast a proxy price for the Kudu natural gas. From the values shown in Figure 3-2 it appears that Henry Hub prices will increase significantly over the 10-year period (from 2011 to 2020) and that European and Henry Hub prices could become closer in the future. It is noted that on December 11, 2015, the natural gas price at Henry Hub was approximately US$ 2/MMBTU, i.e. some US$ 1.9/GJ.

Given the physical location of Namibia, the current LNG prices and its likely LNG sources, one could argue that a modified Sproule's price forecast for the European gas could be more reasonable for use in this NIRP Update study. It is also important to note that the prices presented in Figure 3-2 are the ones at main hubs and they do not include the component required to transport the gas to its final destinations. For natural gas price forecasts beyond 2025, it is assumed that the trend from 2020 to 2025 would be followed from 2026 to 2034.

Given the above, it is assumed that the delivered cost of Kudu natural gas would be in the order of US$ 10/GJ.

3.4.5 Estimate of Natural Gas Price from Liquefied Natural Gas

Natural gas transported as LNG needs to go through the LNG chain from its production at a well to the use for electricity generation in a power plant, i.e. production, liquefaction, transportation, regasification and transport to the power plant location. The price of gas delivered at a power plant must therefore include all cost contributions from these five processes.

Although LNG supply under spot and short term contracts (with duration of four years or less) has decreased over the past couple of years, LNG transactions have mainly been based on long-term contracts lasting for 20 or more years. The prices of some of these long-term contracts are indexed at approximately 90% of crude oil prices. The terms and conditions of the long-term contracts will include at least several key clauses such as annual supply quantity, price, delivery format (such as FOB – free on board and destination) and price adjustment mechanism. The LNG FOB price usually covers two components in the LNG chain, production and liquefaction. As an LNG contract is subject to many factors, its price therefore varies widely, from a couple of US$ per GJ to some US$ 15 per GJ, i.e. from N$ 32 to N$ 240 per GJ. An LNG FOB price of US$ 6 per GJ (N$ 90/GJ) is assumed in this study.

A transportation cost of US$ 50 per tonne will convert to a rate of US$ 1 per GJ based on the assumption that the heating value of LNG is 50 GJ per tonne. In this estimate it was assumed that the lease fee of one LNG vessel with a capacity of 135,000 cubic meters would be some US$ 100,000 per day and each LNG delivery trip would require the ship for some 30 days.

In order to estimate the costs associated with the other two processes, i.e. regasification and transmission, it is necessary to estimate the LNG requirements of a CCGT power plant. Presuming natural gas with a heating value of 1,050 GJ per MMCF (million cubic feet) or 50 GJ/Tonne and a 150 MW CCGT unit with a heat rate of 7.4 GJ per MWh (HHV) and an annual capacity factor of 85%, the daily and annual gas consumption of two 150 MW units would be some 43 MMCF (906 tonnes of LNG) and 15,743 MMCF (330,600 tonnes of LNG) respectively.

As per commercially available technologies, regasification of LNG could be processed via either an on-shore based LNG receiving terminal or a floating storage and regasification unit (FSRU). An on-shore terminal needs a very large amount of capital investment and could handle some 6 to 12 million tonnes of LNG per year. For this project, a small scale FSRU is adequate to deliver the required amount of natural gas which can be leased as opposed to a permanent land based facility. It is estimated that the capital cost of the FSRU will be some US$ 250 to US$ 350 million. With an assumption of 15 years of capital repayment period, 15% return requirement on capital and operation and maintenance (O&M) cost of 3% of capital investment, the annual rental and O&M cost of the FSRU will be some US$ 50 to US$ 70 million, or US$ 3.04 per GJ to US$ 4.26 per GJ.

By assuming the pipeline from the floating terminal to the CCGT power plant to be 20 km long, the unit capital cost of US$ 2.5 million per kilometre, a capital repayment period of 15 years, 15% return requirement and O&M cost of 3% capital investment, the annual capital repayment and O&M cost of the pipeline will be some US$ 10 million per year, i.e. US$ 0.61 per GJ.

Based on the above calculations, the estimated unit cost of the natural gas will be some US$ 11.65 per GJ to US$ 12.86 per GJ. Taking into account 10% allowance for losses and other contingency factors, the unit cost will be some US$ 12.81 per GJ to US$ 14.15 per GJ. Based on this, an LNG gas price of US$ 13.5 per GJ (N$ 216 per GJ) will be used in this study.

3.4.6 Coal Price Forecast

The coal prices shown in Figure 3-3 were obtained from forecasts by the EIA, WB and KPMG and are for the FAS (free alongside ship) or FOB (free on board) prices and do not include the fees and costs for internal unloading, loading and transportation. It is noted that the price from the EIA is for exported coal produced in the U.S., the WB forecast is for Australian coal and the KPMG forecast is for Australian thermal coal. It is possible that the higher EIA price has a significant portion of coking coal.

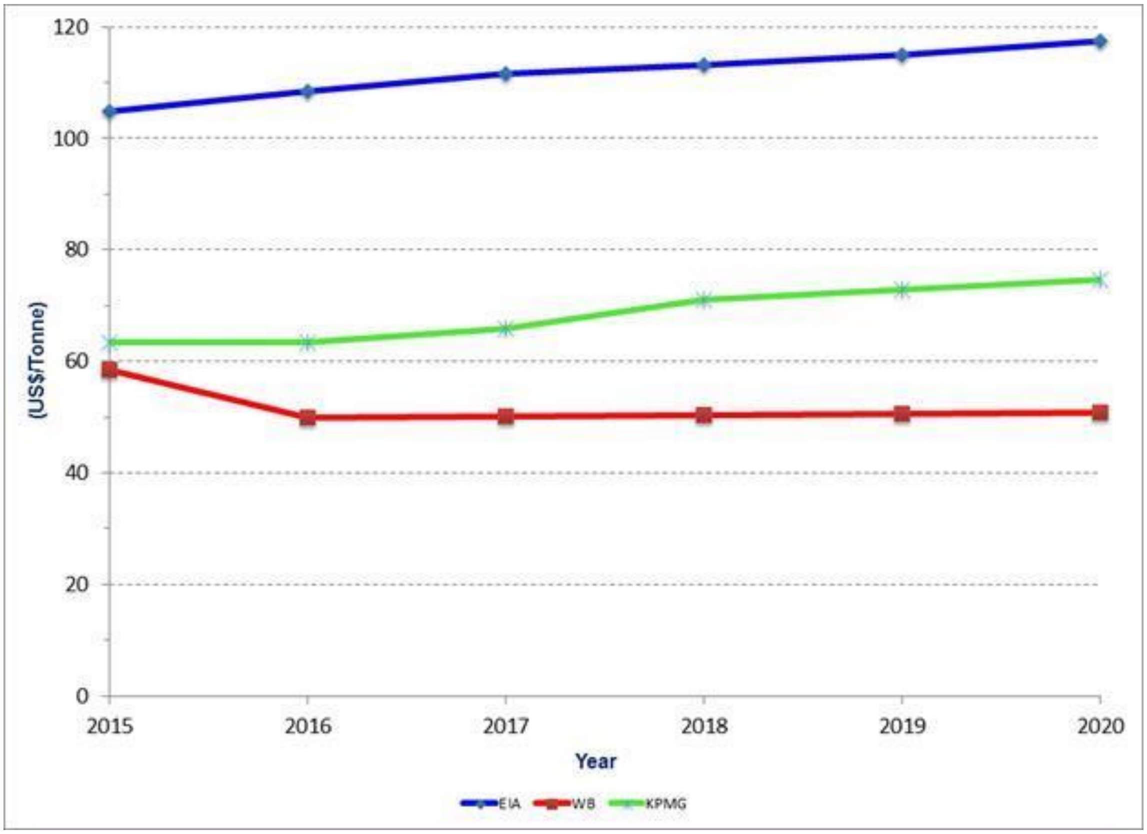

Figure 3-3: Coal Price Forecast

As can be seen from Figure 3-3 there is a wide range of prices by 2020 with forecast prices ranging from about 50 US$ per tonne to 115 US$ per tonne. It must be noted that energy prices are relative amongst themselves and this can be seen by comparing the WB forecasts for crude oil and coal. The EIA forecast appears to be quite high and its starting point is some US$ 40 per tonne higher than prevailing prices.

The NIRP Update will use an average coal price of US$ 50 per tonne for the entire period plus US$ 20 per tonne for shipping, handling (including expansion facilities at a given port) and delivery to a power plant close to a major port.

3.4.7 Price Forecasts for Other Fuels

In addition to the fuels mentioned above, the NIRP Update considers generation technologies that use other fuels such as uranium, municipal solid waste, biofuels and biomass and as such a fuel price forecast for these is needed.

There are several ways of quoting prices for uranium but the ultimate measure, like for any other fuel, is the unit price per GJ or other energy measuring unit. For the NIRP Update, it is assumed that uranium is to be priced at US$ 1.0/GJ (for each GJ of electricity output, not the energy input).

Several studies in the US and Europe have been carried out to determine the cost of collecting and delivering municipal solid waste taking account that in this case the tipping fees for normal refuse would be saved. The estimated cost of collecting and delivering the municipal solid waste to a plant using this fuel is US$ 135 per tonne in the United States. As no specific information was located for Namibia it is assumed that the cost would be half that amount in Namibia or US$ 67.5 per tonne or N$ 1,080 per tonne.

Biofuels, especially biodiesel from Jatropha, have increased in production significantly in the last decade. Presently, biodiesel is a reality in many parts of the world and large plots of land are dedicated to crops that can produce this type of fuel. In locations with suitable growing conditions it is possible to produce and bring to market biodiesel at US$ 3.0 per US gallon or US$ 0.79 per liter (N$ 12.64 per L). However, biofuels are not expected to be important in Namibia during the forecast period.

Encroacher bush has tremendous potential in Namibia to fuel small biomass plants. Given that this fuel is labor intensive and requires machinery to cut the bush and transport it to a central plant it is assumed that the bush chip feedstock would cost about N$ 850 per tonne,

3.4.8 Heat Content of Fuels and Unit Prices of Energy

The previous sections have provided prices of fuels in various units. This sections converts all these prices to a common unit of which the GJ has been selected. In order to do this one requires the different values of heat content of each fuel. It was assumed that the HFO price would be 70% of the crude oil price, i.e. US$ 56/BL, including transportation, refining, handling and delivery while the LFO price would be 130% of the crude price.

Table 3-1 provides the heat content of the various fuels previously mentioned.

Table 3-1: Heat Content of Fuels (HHV)

Fuel	Heat Content	Unit
LFO	6.22	GJ/BBL
HFO	6.65	GJ/BBL
Natural Gas	37.26	MJ/M^3
Coal	27.91	GJ/Tonne
MSW	10.00	GJ/Tonne
Biofuel	33.30	MJ/Liter
Biomass (Invader Bush)	16.00	GJ/Tonne

Taking into account the prices of the fuels provided in the above section and the heat content of these, the unit prices of energy are given in Table 3-2.

Table 3-2: Unit Price of Fuels (HHV)

Fuel	Fuel Price	
	(US$/GJ)	(N$/GJ)
LFO	16.71	267.33
HFO	8.42	134.72
Kudu Natural Gas	10.00	160.00
NG from LNG	13.5	216.00
Coal	2.51	40.16
Uranium	1.00	16.00
MSW	6.75	108.00
Biofuel	23.72	379.52
Biomass (Encroacher Bush)	3.32	53.13
Geothermal	8.00	128.00

4. Generation Resources and Options

4.1 Introduction

This section provides descriptions of the fuel resources and their associated power generation options which will be taken into account in the preparation of the NIRP Update. The fuel resources include both domestic and imported resources such as natural gas, LNG, coal, uranium, fuel oil, hydro, wind, solar, biomass, municipal waste, biofuels and geothermal. In order to assess the quantity of these resources and evaluate the maturity of the generation technologies using these resources at appropriate levels, generation options have been divided into the following three groups:

1. Primary options with quantified resource and commercially available and proven technologies for which the cost and timing of deploying the technology in Namibia can be quantified with reasonable confidence. These would include natural gas including LNG, coal, uranium, fuel oil, hydro, wind, solar and biomass.
2. Secondary options with quantified resource but non-mature technology. Small module nuclear reactors fall into this group.
3. Secondary options with mature technology but non-quantified resource. A few examples of these are potential sites for hydro, wind, solar, municipal solid waste, biofuels and geothermal for which no detailed studies have been completed.

4.2 Primary Generation Resources

This section of the report presents a brief outline of each of the primary resources selected to meet the growing electricity demand in Namibia.

4.2.1 Coal Fired Power Generation

Coal resources are available in almost every country around the world, with recoverable reserves in some 70 countries. It has been estimated that the proven coal reserves are enough to last for well in excess of 120 years at the current rates of production. In contrast, the proven oil and gas reserves are equivalent to some 50 and 60 years respectively at the current production levels.

Coal deposits in Namibia have not been commercially exploited. All coal used in the country is imported from either South Africa or other countries. Coal deposits in Namibia are stratigraphically confined to the Ecca Group of the Karoo Sequence. Coal potential exists in extensive sedimentary basins like the Owambo, Huab, Waterberg and Aranos basins. The Aranos basin has been investigated in detail for coal and contains in situ resources of about 350 million tonnes of high-quality metallurgical coal at a depth of up to 300 m, which makes it the largest known coal deposit in the country. At this time, most of these coal resources cannot be economically developed when comparing with development of coal mines in other Southern Africa countries, especially South Africa, Botswana and Mozambique. Coal resources in these Southern Africa countries are considered to be more than sufficient to supply a large power plant in Namibia over the course of its normal life.

South Africa exports about 30% of its coal production mainly through the Richards Bay Coal Terminal, making the country one of the top coal exporting countries in the world. Coal supply to a power plant in Namibia could be secured through a long term coal supply agreement with one or more coal mines in that country or in the region. In general, regional coal mines should prove to be the most economic sources due to shorter transport routes and lower transport cost. However, this may be offset by anticipated increasing transport cost, supply risks and increasing handling costs due to political and economic instability.

Power generation using coal normally involves three major stages, coal mining, transportation of coal to the power plant and conversion of the coal into electricity. It is understood that cost reduction in any of the three stages could eventually reduce the cost of unit electricity production. When selecting a coal fired power plant site, several important factors need to be taken into account including land availability, fuel source, fuel transportation, electricity transmission, water availability, ash disposal, environmental and socio-economic impacts.

A conventional coal fired generating unit is comprised of a coal-fired boiler to convert the energy contained in the coal into heat and high pressure steam which is then used to drive a steam turbine coupled to an electricity generator. Due to its relatively high initial investment cost and technical constraints, a coal fired generating unit is normally used to supply base load in order to reduce the unit energy cost. This implies that a coal-fired generating unit should be dispatched at its highest available output most of the time in order to achieve economies of scale. As the primary fuel for electric power generation, generation technologies using coal have experienced a long development process and most of them are well established and proven.

The commonly used coal-fired power generation technologies in the modern power industry include pulverised coal (PC) combustion with/without installation of flue gas desulphurization (FGD) equipment and circulating fluidised bed (CFB) combustion, which are technically proven and have very well defined cost estimates. The PC with FGD and CFB combustion technologies would also reduce SO2 emissions. One of the main advantages of the CFB combustion against PC combustion is that the former could use a variety of fuels and does not require FGDs.

Coal is becoming more controversial due to its high level of greenhouse gas (GHG) and other emissions (if they can’t be abated in a cost effective manner) when compared to other primary energy options. The most advanced technologies for coal power generation are integrated gasification combined cycle (IGCC) and carbon capture and sequestration (CCS), which could significantly reduce emission of GHG into the atmosphere. These two technologies will of course increase the initial capital investment significantly as well as O&M cost and therefore increase the unit cost of electricity. It has been estimated that the CCS could increase the capital cost of a coal-fired power station by around 35%. As understood, construction of a CCS is subject to geographical and geological constraints and such a facility could only be built at limited locations.

The size of a coal fired generating unit can range from 10 MW to over 1,000 MW. The typical service life of a coal fired generating unit could vary from 30 to 50 years. However, in economic and financial analysis, an economic life of 20 to 30 years is normally used. Based on the potential electric load growth over the next 20 years, the unit size of around 150 MW would be suitable for the Namibia electric system. Larger sized units could result in excessive base load generation capacity and higher operating reserve obligations as determined by SAPP. Excessive based load generation implies that internal customers could not consume all energy generated over the off-peak periods and, if the unit could not be economically curtailed or shut down during this period part of the output must be sold to the external markets at much lower prices than the average generation cost. In some cases, the base load energy prices could be negative, i.e. the generators must pay the customer to consume electricity. This situation has already occurred in some electricity markets.

The higher operating reserve obligations (due to larger unit size) means that the Namibian electric system must operate and maintain other units to provide spinning reserve and quick start reserve which normally have high incremental generation cost. The Namibian electric system operator can, of course, purchase a certain amount of spinning and quick reserves from other SAPP countries depending on the SAPP rules.

The lead time to develop the 150 MW coal generating unit could be six to seven years if a standard (or off-the-shelf) technology is selected, which includes scoping study, feasibility study, environmental impact assessment, tendering documents, EPC (engineering, procurement and construction) documentation and bid evaluation, negotiation of financing and financial closing, construction and commissioning. Larger sized units, new technologies or sea water cooling may have a longer lead time. Fast tracking could of course reduce the lead time considerably especially if some of the steps outlined above are bypassed by using balance sheet financing and carrying out some of the steps on a concurrent basis.

In Namibia, the existing Van Eck coal fired power station located in Windhoek uses coal imported mainly from South Africa. This plant has been used as standby over the last several years due to environmental constraints, high coal transportation cost, low efficiency and low cost of power imports from other SAPP countries.

A scoping study for development of a coal fired power plant in Namibia was completed a few years ago and the plant could be located in the Erongo Region and is often referred to as the Erongo Coal Power Plant. Such a plant would first be constructed with two 150 MW units and could be expanded with more units up to a total capacity of 800 MW when required.

For the NIRP Update study, the candidate coal-fired power plant with a unit size of 150 MW using either CFB or PC technology has been selected as it fits well with system demand requirements for the near future. The following is a short description of the factors for a standard CFB power plant and a PC power plant without installation of FGD equipment and explanations to the parameters presented in Table 4-1:

1. The CFB and PC technologies for the 150 MW unit size have been utilised in many power plants around the world and are commercially available and technically proven.

2. For the Erongo Coal Power Plant, CFB combustion was recommended against the PC combustion due to the fact that the CFB could use a variety of fuels including encroacher bush which is available in Namibia, have a minimum loading requirement as low as some 35% of its full output and remove most sulphur in the coal during the combustion. The low minimum loading requirement of the CFB technology could have advantages to the Namibian electric system.

3. Due to environmental and social issues including community opposition, with a coastal location, an inland site was selected.

4. The coal required by the plant could be supplied from Richards Bay, South Africa as both resources and infrastructure are in place at that location. The coal could also be imported from Mozambique and Botswana if necessary. Part of the required coal could also be substituted by locally harvested encroacher bush.
5. With a total net capacity of 300 MW for the first phase, the annual coal consumption has been estimated at some 1 million tonnes. The current unloading facilities at Walvis Bay harbor and rail transport of the coal to the coal power plant site would need moderate upgrades and investments.
6. The fuel price used in the study is the price for fuel to be delivered to the plant site, i.e. including all transportation and handling costs.
7. Several alternatives had been investigated for the plant cooling technology in the scoping study of the Erongo coal power plant, of which a dry air-cooled condenser had been identified as the optimum solution. Its main advantages are the low water consumption, low investment cost and ease of operation.
8. A list of potential EPC contractors had been identified in the Erongo power plant scoping study. Most of them are from India, China and Korea and only one is from Japan. It is noted that the EPC bidding prices from these contractors could be much lower than those from Western economies based contractors.
9. The lead time would be some six to seven years, including scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning. A fast track approach could be used to shorten the lead time to 4 years.
10. It is expected that the equivalent availability of a unit would be around 85%, which is based on the information available in the NERC database. Its capacity factor could, therefore, only be up to this value as the unit might not produce at its full capacity all the time due to various reasons such as low load demand, contribution to spinning reserve obligation, etc.
11. The EPC costs for CFB and PC technologies have been estimated at US$ 1,700 (N$ 27,200) per net unit capacity (kW) and US$ 1,500 (N$ 24,000) respectively, which do not include interconnection costs.
12. Owner’s cost has been estimated at 10% of the total EPC cost.
13. The construction time for a 150 MW coal fired plant would be some three years, with a cash disbursement of 30%, 40% and 30% in year 1 to year 3 of construction respectively. In order to align the capital expenditure to the in-service date, the base discount rate is used to calculate the interest during construction (IDC).
14. 1.5% of the sum of EPC, owner’s cost and IDC is assumed to be the financing charges including commitment fees.
15. 2% of the sum of EPC, owner’s cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit’s operation.
16. Fixed O&M cost was calculated based on 3% of the unit’s total capitalised cost, including insurance.

17. Variable O&M cost was assumed as N$ 400 per MWh.

18. Emission rates of CO_2, NO_x, SO_2 and particulate matter are the uncontrolled factors calculated based on the parameters for CFB, PC and ESP (electrostatic precipitator), collected from the U.S. EIA and EPA. The SO_2 emission factor was calculated based on 1% sulphur coal. The PC combustion option will have higher emission factors of NO_x and SO_2.

4.2.2 Natural Gas Including LNG Fueled Power Generation

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane, with up to 20 percent concentration of other hydrocarbons (usually ethane) as well as small amounts of impurities such as carbon dioxide. Natural gas is widely used and is an important energy source in many applications including heating buildings, generating electricity, providing heat and power to industry and vehicles and is also a feedstock in the manufacture of products such as fertilizers.

Natural gas is commercially extracted from oil fields and natural gas fields. Gas extracted from oil wells is called casing head gas or associated gas. The natural gas industry is extracting gas from increasingly more challenging resource types: sour gas, tight gas, shale gas, and coal bed methane.

Total world proven natural gas reserves, as of October 2015, were more than 200 trillion cubic meters (TCM; or 7063 trillion cubic feet - TCF)[2]. At current production rates, which was estimated at 3.2 trillion cubic meters per year, this would last more than 60 years. Reserves have grown about 2% per year. With production also growing, the reserve-to-production ratio has stayed within the range of 58 to 68 years since 1985. The top four countries with the largest reserves are Russia (48.7 TCM), Iran (33.6 TCM), Qatar (24.7 TCM) and Turkmenistan (17.5 TCM).

The efficient and effective movement of natural gas from producing regions to consumption regions requires an extensive and elaborate transportation system. In many instances, natural gas produced from a particular well will have to travel a great distance to reach its point of use. The transportation system for natural gas consists of a complex network of pipelines, designed to quickly and efficiently transport natural gas from its origin to areas of high natural gas demand. Transportation of natural gas is closely linked to its storage. Should the natural gas being transported not be immediately required, it can be put into storage facilities for use when it is needed.

Because of its low density, it is not easy to store natural gas or transport it by vehicle. Natural gas pipelines are impractical across oceans. In these cases, gas can be turned into liquid at a liquefaction plant, and is returned to gas form at a regasification plant at the terminal. Ship borne regasification equipment can also be used. LNG carriers transport LNG across oceans, while tank trucks can carry liquefied or compressed natural gas (CNG) over shorter distances. Sea transport using CNG carrier ships that are now under development may be competitive with LNG transport in specific conditions. As per the industrial practice, LNG is the preferred form for long distance, high volume transportation of natural gas, whereas pipeline is preferred for transport for distances up to 4,000 km over land and approximately half that distance offshore.

[2] List of countries by natural gas proven reserves - Wikipedia, the free encyclopaedia

The global LNG trade in 2013 was at 236.8 MT (million tonnes), slightly below the peak of 241.5 MT reached in 2012. There are several operational liquefaction plants in African countries including Algeria, Angola, Egypt, Equatorial Guinea, Libya and Nigeria.

In Namibia, the Kudu gas field is situated approximately 170 km off-shore to the south-west of the city of Oranjemund in the south western corner of Namibia. The gas field is located about 4.5 km underground and would require an under-sea pipeline to reach the shore. Water depth at the site is around 170 meters.

The Kudu offshore gas field, discovered in 1974, is estimated to contain 1.3 trillion cubic feet (37 billion cubic meters) of proven natural gas reserves. However more recent exploration and analysis suggests that reserves could reach 3 trillion cubic feet (85 billion cubic meters) with a potential much higher than the suggested reserves.

The gas from the Kudu gas field is a sweet gas requiring little cleaning and processing and is available at a certain pressure and temperature. At the present time it is envisaged that the gas would be processed on a floating plant system (FPS) to be contained in a permanently moored large ship and from the FPS an undersea 170 km long pipeline would be constructed to bring the gas to Namibian soil at Uubvlei (close to Oranjemund) where it would be used to supply a 900 MW power plant.

Various gas turbine technologies have been developed and used around the world by using natural gas or light fuel oil to generate electricity. In this case, instead of heating steam to turn a turbine, hot gases from combusting fossil fuels are used to turn the turbine and generate electricity. Gas turbine plants are traditionally used primarily for meeting peak-load demands, as it is possible to quickly and easily turn them on. These plants have increased in popularity due to advances in technology and the availability of natural gas. Gas turbines can be combined with a steam turbine to form a combined cycle unit. In combined-cycle plants, the waste heat from the gas-turbine process is directed toward a heat recovery steam generator (HRSG) which in turn supplies steam to a steam turbine to turn an electric generator. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than steam units or gas turbines alone.

The size of a single gas turbine could range from a few MW to some 500 MW. Selection of the single unit/plant size is determined by several important factors such as system operating reserve, system regulations, generation adequacy, plant/load locations, load magnitude and its variability, fuel availability, and cost and transmission/distribution access. For the NIRP Update study, the net sizes selected for CCGTs are 150 MW and 450 MW (as per the information obtained from the Kudu Gas Power Project) and the net sizes for GTs are 50 (the proposals received for LNG based power plants have included several 50 MW units) and 100 MW. In the case of a 450 MW unit, it is expected that there would be one GT, rated at some 300 MW and one steam turbine rated at 150 MW (the current plant design of the Kudu Gas Power Project). It is noted that two 450 MW units were recommended by the Kudu Gas-to-Power Project Study although this size is quite large for the Namibia electric system and it would increase the Namibia system's operating reserve obligation, which at present stands at 35.6 MW (17.8 MW of spinning reserve plus 17.8 MW of quick start reserve).

Based on the Kudu Gas-to-Power Project Study, the power station near Oranjemund is being designed for a 884 MW net capacity, approximately one half of which (442 MW) would be consumed by Namibia customers and the rest would be sold to utilities outside Namibia through long term power sale contracts. The total amount of gas available to the Kudu project is contractually limited to 584 PJ (petajoule). This amount of available gas is insufficient for continuous year round operation of the Kudu power plant at its full capacity over the power plant life. It has been estimated that the 584 PJ could fuel the power plant for 15 years.

Studies have determined that the power station and an 18 inch gas pipeline from the gas field to the power station would be designed and constructed in such a way that the power station could be operated in a more flexible manner targeting mid merit/peak periods. The current proposal is for the power plant to supply mid-merit and peaking load in Namibia and base load in outside markets. The additional cost in the design of Kudu power plant and the pipeline for creating operating reserves for mid merit/peaking may not be significant relative to the benefits of operational flexibility, risk management and potential commercial advantages. The operational flexibility is particularly valuable to NamPower as its other major supply option is the run-of-the-river Ruacana hydro power station. Ruacana cannot run at its full capacity for a large part of a year due to low water inflow and limited storage capacity.

In this study, two sizes for each of CCGT and GT candidates are taken into account in development of generation expansion sequences. The CCGT sizes are 150 MW and 450 MW while the GT sizes are 50 MW and 100 MW. The following is a short description of the factors for the selected CCGT and GT sizes and explanations to the parameters presented in Table 4-2:

1. The CCGT and GT technologies for the selected size ranges are technically proven and commercially available and have been widely used in electric power generation around the world.

2. The CCGTs and GTs could be fueled by either Kudu natural gas or imported LNG. In the case of Kudu gas, a pipeline from the gas field would be required while in the case of LNG, LNG would be shipped from the LNG production countries and then be re-gasified in Namibia using a FSRU. It is important to note that all natural gas prices are assumed to be the delivered prices to a plant.

3. The infrastructure for natural gas transportation and/or regasification is at present not in place. This may take a relatively long time to build and need government support to bring this on line.

4. It is expected most EPC contractors for a CCGT or GT plant would come from India, China and Korea and the EPC bidding prices from these contractors would be lower than those estimated using the developed economy standard. However, the major equipment for a plant could still be procured from the manufacturers located in the developed economy countries.

5. The lead time for a CCGT plant could be some five to six years while it could be one year shorter for a GT plant, including scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning. Given the studies already carried out, the progress made to date in project structuring and the status of the negotiations with the upstream developer or IPP, the lead time for Kudu power project would be three and a half to four years.

6. It is expected that the equivalent availability of a plant would be from 87% to 90%, based on the information from the NERC database. Its capacity factor could, therefore, be only

up to this range as the plant might not produce at its full capacity at all times due to various reasons such as low load demand, contribution to spinning reserve obligation, etc.

7. Supply of natural gas or LNG could be arranged through a take-or-pay contract. This means that the monthly payment would be fixed no matter if the fuel would be consumed by the power plant.
8. The EPC costs for CCGT 450 MW, CCGT 150 MW, GT 50 MW GT 100 MW have been estimated at US$ 800 (N$12,800) per net unit capacity (kW), US$ 850 (N$ 13,600), US$ 700 (N$ 11,200) and US$ 650 (N$ 10,400) respectively.
9. Owner's cost has been estimated at 10% of the total EPC cost.
10. The construction time for a CCGT unit would be some three years, with a cash disbursement of 30%, 40% and 30% for year 1 to year 3 respectively, while the construction time for a GT unit is two years with a cash disbursement of 60% and 40%. In order to align the capital expenditure to the in-service year, the base discount rate is used to calculate the interest during construction (IDC).
11. 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
12. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
13. Fixed operation & maintenance (O&M) cost (including insurance) was calculated based on 3% of the unit's EPC cost.
14. Variable O&M cost was assumed at N$ 240/MWh.
15. Emission rates of CO2, NOx, SO2 and particulate matter are the uncontrolled factors calculated based on the factors collected from the US EIA and EPA. It is expected the current CCGT and GT technologies would reduce the NOx by 90%. The SO2 emission factor was calculated based on 1% sulphur natural gas.

4.2.3 Fuel Oil Fired Power Generation

The total proven oil reserves in the world were estimated at some 1.48 trillion barrels in September 2013[3]. The three countries with most oil reserves around the world are Venezuela with 298 billion barrels, Saudi Arabia with 268 billion barrels and Canada with 174 billion barrels.

Because the geology of the subsurface cannot be examined directly, indirect techniques must be used to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, significant uncertainties still remain. In general, most early estimates of the reserves of an oil field are conservative and tend to grow with time; many oil-producing nations do not reveal their reservoir engineering field data and instead provide unaudited claims for their oil reserves.

Future reserves growth will depend, to a large extent, on increases in the recovery factor, which is estimated to average about 35% worldwide today. Such increases, through

[3] List of countries by proven oil reserves - Wikipedia, the free encyclopaedia

secondary and enhanced oil recovery techniques and other factors, could make a big difference to recoverable reserves, prolonging the production life of producing fields and postponing the peak of conventional oil production.

There are ongoing oil exploration activities both off shore and on shore in Namibia. It appears that the geological formations off the coast of Namibia are very similar to those of pre-salt fields in Brazil and thus the prospects of finding commercial exploitable oil resources are very attractive.

Crude oil is extracted from oilfields located on land or offshore and is then converted to more refined products in large oil refineries. Several petroleum products emerge from the refining process including gasoline, diesel oil, heavy fuel oil (or Bunker C) and with today's new cracking processes petcoke. Most of the liquid petroleum products can be used to generate electricity by using a variety of technologies. Four main technologies are used to convert petroleum products (including both light fuel oil (LFO) and heavy fuel oil (HFO) into electricity:

1. Conventional steam – HFO or Petcoke is burned to heat water to obtain steam to drive a turbine which in turn drives an electrical generator.
2. Combustion turbine – LFO is combusted under pressure to produce hot exhaust gases, which spin a turbine to generate electricity.
3. Combined-cycle technology – LFO is first combusted in a combustion turbine and then the exhaust gases of the turbine are fed to a HRSG which produces steam that is used to drive a steam turbine and subsequently an electrical generator.
4. Internal Combustion Reciprocating Engines – these engines use combustion of a fuel (LFO or HFO) to push a piston within a cylinder that turns a crankshaft to generate electricity. Reciprocating engines that use compression ignition (these are often referred to as diesel engines) are the most common for power generation. These are referred to as ICREs in this report to avoid confusion with diesel fuel.

Conventional steam technology using HFO was not considered as a candidate generation alternative because other technologies are more economic. The use of Petcoke was not considered for use on conventional steam technology due to serious environmental considerations as well as emissions associated with this fuel. This fuel appears to be more commonly used when blended with coal.

ICREs can use a variety of fuels including light fuel oil (LFO) (diesel oil or No. 2), HFO (No. 6) of various degrees of viscosity and a variety of biofuels (biodiesel and fats). There are 3 principal types of ICREs; high speed, medium speed and low speed. Each offers its advantages and comes in different sizes. For large amounts of power production it appears that the most commonly used engine is the medium speed with some installations using low speed engines. The largest ICRE used for electricity generation to date has a capacity of about 83 MW.

For the NIRP Update, 20 MW medium speed ICRE generators operating on HFO will be considered as well as the LFO fueled 150 MW CCGTs, 50 MW GTs and 100 MW GTs. ICREs used in large electrical generators run at approximately 400 to 800 rpm and are optimised to run at a set synchronous speed depending on the generation frequency (50 or 60 hertz) and provide a rapid response to load changes. The largest ICREs in production are in sizes of up to approximately 20 MW supplied by companies like MAN B&W, Wärtsilä, and Rolls-Royce. Most ICRE engines produced are four-stroke machines, however there are some two-stroke ICREs manufactured by others.

The parameters presented in Table 4-3 for CCGT and GT technologies are similar to those given in Table 4-2, except for heat rate, fuel cost and emission factors. Therefore the following presents only the descriptions and explanations to the differences:

1. The ICRE, CCGT and GT technologies using fuel oil for the selected size ranges are technically proven and commercially available and have been widely used in electric power generation around the world.
2. The cost for infrastructure required for fuel oil transportation is included in the estimated fuel cost.
3. It was assumed that the EPC contract would be awarded to contractors from the developing economy countries. The bidding prices of the bidders from the developing economy countries would be lower than those estimated using the developed economy standard. The major equipment for a plant could still be procured from the manufacturers located in the developed economy countries.
4. It is expected that the equivalent availability of an ICRE, CCGT and GT would be some 90%, 87% and 90% respectively based on the information from the NERC database. Their capacity factors could, therefore, be only up to these values as the plant might not produce at its full capacity at all times due to various reasons such as low load demand, contribution to spinning reserve obligation, etc.
5. The EPC costs for ICRE 20 MW, CCGT 150 MW, GT 50 MW and GT 100 MW have been estimated at US$ 1,100 (N$ 17,600) per net unit capacity (kW), US$ 850 (N$ 13,600), US $700 (N$ 11,200) and US$ 650 (N$ 10,400) respectively.
6. The construction time for an ICRE would be some two years with a cash disbursement of 60% and 40%. In order to align the capital expenditure to the in-service date, the base discount rate is used to calculate the interest during construction (IDC).
7. Variable O&M cost was assumed as N$ 240 per MWh for ICREs, CCGTs and GTs.
8. Emission factors of CO2 and NOx were calculated based on the information obtained from the EIA and EPA. It is recognised that the emission factors for GT and CCGT using LFO would be different from those using natural gas.

4.2.4 Nuclear Power Generation

It is estimated that some 5.4 million metric tonnes of uranium ore reserves are economically viable around the world[4] while 35 million metric tonnes are classified as mineral resources (reasonable prospects for eventual economic extraction). The worldwide production of

[4] List of countries by uranium reserves - Wikipedia, the free encyclopaedia

uranium in 2014 amounted to 56,252 metric tonnes, of which more than 40% was mined in Kazakhstan. The five next most important uranium mining countries are Canada (16.2%), Australia (8.8%), Niger (7.2%), Namibia (5.8%) and Russia (5.3%). This shows Namibia the fifth largest producer of uranium ore in the world. It is noted that a number of new uranium mining licenses have been issued by the MME which are expected to increase Namibia's annual uranium output from 2016, notably from the Husab Mine.

Uranium ore is mined in several ways, open pit, underground, in-situ leaching, and borehole mining. Commercial-grade uranium can be produced through the reduction of uranium halides with alkali or alkaline earth metals. Uranium metal can also be prepared through electrolysis of KU5 or UF4, dissolved in molten calcium chloride (CaCl2) and sodium chloride (NaCl) solution. Very pure uranium is produced through the thermal decomposition of uranium halides on a hot filament.

As nuclear power generation has become established since the 1950s, the size of reactor units has grown from 60 MW to some 1,600 MW, with corresponding economies of scale in operation. At the same time there have been many smaller power reactors built both for naval use and as neutron sources, yielding enormous expertise in the engineering of small units. As per the definitions from the International Atomic Energy Agency (IAEA), the generating units are divided in three size groups. The "small" group includes those units less than 300 MW, the "medium" group is for those between 300 and 700 MW and the "large" group has the unit size over 700 MW. The last two groups include most operational units from the 20th century. The most common types of nuclear power plants include pressurised water reactor (PWR), boiling water reactor (BWR), gas cooled reactor (GCR) and advanced gas cooled reactor (AGR), light water cooled graphite moderated reactor (LWGR), and pressurised heavy water moderated reactor (PHWR).

As per the information collected from the World Nuclear Association (WNA), there are at present some 439 operable reactors producing electricity for power grids with a total net capacity of 382,248 MW, 64 reactors under construction with a total gross capacity of 67,797 MW, 159 planned reactors with a total gross capacity of 180,015 MW and 329 proposed reactors with a total gross capacity of 374,020 MW. Based on the information collected from the IAEA, the gross unit size of the operable reactors ranges from 12 MW located in Russia to 1,561 MW located in France. Except for the four smallest units, each at 12 MW, and one 25 MW reactor in China, the next smallest sizes are in the 200 MW to 300 MW range, which are located in Argentina, Armenia, China, India, Japan, Pakistan, Russia, Switzerland, United Kingdom and Ukraine. India alone has 17 reactors with net capacity ranging from some 150 MW to 200 MW, 15 of which belong to the PHWR type and the other two are the BWR type. Most of these generators have been in operation for quite some time and apart from those in India no recent medium size generators have been built.

As per international practice, nuclear power generation is relatively expensive and requires a good national technological base and well trained human resources to operate and maintain such power plants. In deciding if and when a nuclear power plant should be constructed in Namibia, a number of factors such as those listed below must first be taken into account:

1. Grid load demand including export. It is noted that from both economic and technical aspects, nuclear power units should be dispatched to supply base load although advanced technologies could allow a nuclear power unit to have relatively flexible output.

The appropriate time to build a nuclear power unit is when the system off-peak load could consume all the unit output. At present, almost all small reactor technologies have not been licensed and approved by relevant authorities as they are for naval use and as neutron sources, for which economics are normally not an important factor in the decision making process.

2. Establishment of an effective national nuclear regulatory authority in Namibia which formulates policies, develops regulations governing nuclear reactors and nuclear material safety, issues orders to licensees, and adjudicates legal matters. It is expected that from establishment of an effective national nuclear regulatory authority the licensing of reactors could take at least seven to ten years. The establishment of a nuclear regulatory commission can also take quite a few years as expertise has to be gathered to be part of such body.

3. Selection of potential power plant site(s) and conduct of site environmental and social impact assessment. In the advanced economy, such assessment for a nuclear power plant could take from five to ten years. It is our understanding that pressure groups are already in place in Namibia and are trying to sway popular opinion.

4. Financing has to be obtained regardless of the intended ownership, private, public or private public partnership. This could be a long and difficult road especially for investors outside Namibia and would require full GRN back up, support and participation especially with guarantees.

5. Construction of a nuclear power generating unit is likely to exceed five years after environmental and required approvals.

6. A nuclear power plant should have access to water and other infrastructure as it requires very large amounts of water for cooling.

7. The output from a nuclear power plant should be evacuated through reliable transmission lines without interruptions in order to minimize the risk of overheating. A nuclear power plant is normally connected to several transmission lines to obtain the desired redundancy. In order to avoid a bottleneck and other operational issues, these transmission lines would have to be connected to a strong point in the grid with several evacuating routes.

8. Maintenance and operation of a nuclear power plant requires considerable technical expertise and a technology base in order to be able to supply the specialist skills and products to a nuclear power station, to which Namibia has never been exposed and may need to import at considerable costs in the initial years of operation.

9. Unless the company operating the nuclear power station also operates a uranium mine and a uranium processing plant, the company will have to import the enriched uranium for electric power generation from the international market and thus pay the international price. This is a factor that needs to be considered by investors.

10. In most jurisdictions, nuclear power generation option requires considerable government interventions with regards to stipulations contained in international conventions, safety regulations, funding and technical facilitations, identification of countries from where safe and proven technologies and initial human expertise can be sourced, as well as

establishment of a plan to train more Namibians in nuclear physics and nuclear engineering.

11. The Government should also play a sustainable role in negotiating power purchase agreements with countries within the region or within the SAPP. Regional cooperation is required as the generation capacity of even a small nuclear power plant may exceed Namibia's ability to absorb the full generation capacity.
12. It is noted that after Japan's Fukushima nuclear disaster caused by the 8.9 magnitude earthquake on March 11, 2011, Germany has permanently shut down eight of its seventeen reactors and pledged to close the rest by the end of 2022. A couple of countries have banned the construction of new reactors. Several countries have called for a reduction in their reliance on nuclear power. As of 2013, there are more than 10 countries remaining opposed to nuclear power, including Australia, Austria, Denmark, Greece, Ireland and Italy while other countries such as Canada are continuing to invest in nuclear power plants.
13. Consideration and/or programs for radioactive waste handling and final disposition including for spent fuels.

In this study, parameters for two reactor sizes, 200 MW and 600 MW are estimated and shown in Table 4-4. The following is a short description of the factors for 200 MW and 600 MW nuclear power plants and explanations to the parameters presented:

1. The nuclear technologies for the selected size ranges are technically proven and commercially available but have not been widely used in the recent past and may require redesign to incorporate the latest technological advances.
2. Unlike the EPC contract for coal, gas and fuel oil fired technologies, it is strongly recommended that the first nuclear plant should be built by a highly experienced contractor from the developed economy countries with proven nuclear power technologies but at the present time there are only a very limited number of such contractors.
3. The lead time for a nuclear plant could be fifteen or more years. Taking into account the fact that the country does not have a nuclear regulatory commission in place, and there are no licensed reactors for the sizes considered, the total lead time for the first nuclear unit in Namibia should be at least 20 years.
4. It is expected that the equivalent availability of a nuclear plant would be around 85%, based on the information from the NERC database. Its capacity factor could, therefore, be only up to this number as the plant might not produce at its full capacity at all times due to various reasons such as low load demand, contribution to spinning reserve obligation, etc.
5. The EPC costs for 200 MW and 600 MW plants have been estimated at US$ 8,000 (N$ 128,000) per net unit capacity (kW), and US$ 7,000 (N$ 112,000).
6. Owner's cost has been estimated at 5% of the total EPC cost.
7. The construction time for a nuclear unit would be some six years, with a cash disbursement of 10%, 15%, 20%, 25%, 20% and 10%. In order to align the capital

expenditure to the in-service date, the base discount rate is used to calculate the interest during construction (IDC).

8. 0.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
9. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
10. Fixed O&M cost was calculated based on 1.5% of the unit's total capitalised cost.
11. Variable O&M cost was assumed as N$ 160 and N$ 128 per MWh for the 200 MW and 600 MW units respectively.

4.2.5 Hydro Electric Power Generation

The 2007 Survey of Energy Resources published by the World Energy Council indicates that Namibia's only perennial rivers are the Kunene, Okavango (forming borders with Angola and Zambia in the north) and the Orange River bordering South Africa in the south. It appears that any plans to develop hydro power are subject to lengthy bilateral negotiations. Another problem leading to limited exploitation of hydro resources is the scarcity of rain and the extensive droughts.

Namibia's hydropower resources have been mapped and studied in the past. It was estimated, in 1992, that Namibia's gross theoretical hydropower potential would be approximately 9,000 GWh per year. In 1990, it was assessed that the country's technically and economically feasible potential would be approximately 8,645 GWh per year. The Kunene River, a shared river with Angola, has a hydropower potential of 1,600 MW and was studied in depth during the 1990's. The potential large-scale hydropower projects identified for further study were the Epupa and Baynes schemes, and were studied in detail at feasibility level in 1997. Both these schemes were originally envisaged as 360 MW plants aimed at ensuring security of base load supply for Namibia. The study found both schemes to be financially viable with Epupa having some negative environmental impacts but being self-sufficient as far as water reservoir capacity is concerned, conversely the environmental impact of the Baynes option was much more acceptable but it relied heavily on the regulation of water to be released from the Gove Dam situated deep inside Angola. The project was shelved and NamPower, in dire need of electricity supply, opted to build a 400 kV power line connecting Namibia to South Africa which facilitated the import of inexpensive electricity from South Africa to Namibia.

A reasonable amount of study work has been done in Namibia with regard to the development of small hydro power plants. Small hydro potential can be found mostly on the Okavango and Orange Rivers, since the Kunene is situated in a remote area. The waters of the Orange River are dedicated to irrigation projects and mining activities.

It was reported that Namibia had developed a hydro power Master Plan for the country but this has not been made available for review. A study on all perennial rivers had been performed. The aim of the study was to identify and estimate cost and production for all potential hydro power projects on the Lower Kunene, Okavango and Lower Orange rivers.

Baynes Hydroelectric Power Plant

The Baynes hydro project on the Kunene River was first considered in 1997 after plans to build the scheme east of Namibia's Epupa Falls received fierce opposition due to concerns regarding the impact on the environment and on the nomadic community in northern Namibia. After carefully considering all options, the Namibian and Angolan governments decided to give the green light for the Baynes development to be studied. This change came about mainly because of the following two factors:

- The changed peace situation inside Angola which made it possible for the Angolans to rehabilitate the damaged Gove Dam inside Angola and to regulate the river flow from the dam which is of vital importance for the success of the Baynes Hydropower development.
- The 400 kV interconnecting power line between South Africa and Namibia that can provide a long-term capacity opportunity for regional power trading.

The potential duty cycle of a Kunene hydropower plant therefore needs to be revisited, particularly as potential exports from Namibia would primarily be targeting peaking and mid-merit opportunities in the Southern African market. Designed for peaking and mid-merit operations, a Kunene power plant at Baynes could potentially provide about 600 MW of additional peaking generation capacity.

It needs to be mentioned that present and future hydropower developments in the Lower Kunene River would benefit considerably from the completion of two initiatives in the Upper Kunene River inside Angola, i.e. further repair of the Gove Dam and the completion of the Calueque Dam. Both these initiatives would improve the upstream flow-regulation of the Kunene River and enhance the performance and cost-competitiveness of a Kunene hydropower plant.

The exploration and exploitation of hydropower developments on a river shared by two countries requires considerable intervention from the concerned governments. In this case, the Namibian and the Angolan Governments were closely involved in laying the foundation for a considerable cross-border investment. Good cooperation between these two governments must continue for the Kunene hydropower plant(s) to be realised. The project also requires considerable regional collaboration on securing the constant flow of water from the hinterland, on bilateral power purchasing arrangements and on joint operations and maintenance programs. The clarification of existing documents regarding water rights for both countries is essential to the development of any hydroelectric project on the Kunene.

The technical and economic feasibility study of the Baynes Hydro Power Plant was completed by a consultant retained by the Joint Permanent Technical Committee of Angola and Namibia for the Kunene River Basin a couple of years ago. The study included three phases. The first phase consisted of review of the previous studies, field inspection and critical assessment of the existing data for next two phases. Phase 2 was characterised by preliminary engineering studies, pre-dimensioning, modeling, energy economic and financial analysis, analysis of alternatives and selection of the most attractive solution. The last phase, i.e. Phase 3 was focused on the improvement of energy, motorization and reservoir depletion, as well as the breakdown of the general arrangement and structure of the plant. The main characteristics of the proposed hydro plant would be as follows:

1. The coordinates of the hydro plant location will be 17^{0}02'44" S and 12^{0}53'22"E.
2. A total of five units with a net maximum generating capacity of some 600 MW.

3. The live storage of the upstream reservoir would have a capacity of approximately 1,300 million cubic meters, which could provide water to the station at its full output for more than 800 hours.
4. The total EPC cost for the plant was estimated about US$ 1.4 billion, i.e. US$ 2,330 (N$ 37,280) per kW of net capacity.
5. The expected annual generation under the average hydrologic condition (50% of exceedance probability) would be some 1,610 GWh, i.e. an annual capacity factor of approximately 30%. Comparing with other hydroelectric plants built in the world, this value is relatively low. This means that the unit energy cost of the hydro station would be relatively high.

It is expected that with appropriate methods of inflow forecasting, the reservoir would be filled up during wet season (summer) and then be discharged during dry season (winter). The monthly energy output over the dry season could be maintained at reasonable levels as per system load demands.

The studies for the 600 MW Baynes hydroelectric plant did not take into account the power evacuation from the plant to the Namibian and Angolan systems. The costs associated with the power evacuation could be considerable and an order of magnitude estimate is provided in another section of this report. Conversations with NamPower indicate that the preferred evacuation route would be to build two 400 kV transmission lines from the plant to a new substation just south of the Ruacana plant and convert the output of Ruacana to 400 kV (from 330 kV) and convert the existing 520 km long 330 kV transmission line from Ruacana to Omburu to 400 kV operation. In addition, there would be another 400 kV from just south of Ruacana to Otjikoto and transmission lines to Angola. There are some issues with this concept in that the Angolan representatives have expressed their desire to be supplied directly from the power plant and the other large issue is that the conversion of the existing 330 kV transmission line from Ruacana to Omburu to 400 kV operation could be problematic. Thus the evacuation of power to the final consumers could become quite expensive.

As Baynes HPP would be on the same river system as Ruacana HPP, it could be a serious concern for having a very large portion of the country’s generation capacity dependent on the water flow on a single river.

Okavango River Hydro Electric Power Generation

In May 2004, NamPower commissioned a prefeasibility study on the viability of a 20 MW hydroelectric plant to be located on the Okavango River in the vicinity of Popa Falls. This development would be a run-of-the-river project and would be connected to the NamPower grid via a 200 km long 132 kV power line. The pre-feasibility study has shown the project to be viable but there are still some environmental issues that need to be resolved such as avoiding the entrapment of sediment in the dam basin, before the development may go ahead. The development plan was rejected by NamPower due to the following main reasons:

1. Concerns over possible damage to the Okavango Delta, located downstream from the falls in neighboring Botswana. The costs of environmental management of the project would be very high.
2. The power output will be only 20 MW.

3. The hydro matrix turbines were found to be not ideal for the purpose for which they were proposed. Bulb turbines could be used as an alternative.

4. Heavy financial commitments to develop the Kudu gas project.

However, NamPower has not ruled out the possibility of this proposal being revisited at some future date. The Namibian Government could actively assist in obtaining funding on concessionary conditions. The Namibian Government's role in this project is limited to ensuring that environmental concerns are addressed and that the resource, set in a prime tourism area, is used in the best interest of Namibia.

Lower Orange River Hydroelectric Power Station

The Orange River catchment area is divided into three catchment subdivisions: the upper, middle and lower catchment areas. Clackson Power Company (Pty) Ltd ("Clackson Power") together with NamPower have been pursuing the possibility of developing several distributed hydro-electric power stations which would be situated in the lower Orange River catchment, more specifically between the Fish River junction to the west and the Molopo River junction to the east. It would begin slightly upstream of the Onseepkans settlement and end just after the Vioolsdrift Weir. The Lower Orange Hydro Electric Power Stations (LOHEPS) project consists of the development of up to 9 small hydro-electric power stations, varying in size from 6 MW to 12 MW with an anticipated total installed capacity of some 100 MW. The potential annual output from these hydro stations would be as much as some 650 GWh. The concept of the project is to divert the flow (run-of-river) of the Orange River through canals and tunnels into turbines which in turn would drive an electric generator. By placing the turbines at strategic derivation points along the river, the kinetic and potential energy of the river would be converted into electrical energy. Recent hydrological studies along the Orange River indicate a potential generation capacity of between 80 MW and 120 MW.

The first phase of the feasibility study for the development of a small-scale hydro-power plant along the lower Orange River has been completed. The next step is for the conclusion of environmental and technical studies that would enable decisions on the project site and cost. NamPower could also earn carbon credits from the hydro-power plant, as there would be no use of water abstraction or water regulation.

Due to the fact that the project is an environmentally clean project but with several issues, and could help alleviate the power shortage in Namibia and SADC region, support for the project has been given by the Namibian and South African Heads of State, the Namibian Ministry of Agriculture, Water and Forestry as well as the Namibian MME.

As with most projects of this nature, considerable licenses and regulatory permits are required. However, it is expected that there will be minimal risk to the investor/lender in terms of legislation and regulatory impacts on the project as the projects have received government support from both Namibia and South Africa. The following permits are currently being obtained from the relevant authorities:

1. Operational agreement and water usage permit from the Ministry of Water Affairs (MWAF) of Namibia.

2. Generation license agreement from ECB.

3. Mining permit from MME.

4. EIA clearance from Namibia and South Africa.

Furthermore, as all power stations would be situated on the Namibian side of the border and above the 100 year flood line, any issue regarding border uncertainty should not impact this project. The LOHEPS projects are presently at a standstill as both NamPower and Clackson Power cannot agree on a method to pursue a way forward. The likelihood of any further progress in the short to medium term is very unlikely especially if other projects under consideration are further developed.

Table 4-5 summarises the main technical and economic parameters for the three hydroelectric power stations described above, i.e. Baynes, Okavango River and Lower Orange River. The following provides short descriptions and explanations to the parameters presented in this table:

1. Generation technologies for all sizes of hydroelectric power units (from less than one megawatt to several hundred megawatts) are commercially available and technically proven in the world. However, due to the nature of a hydroelectric power plant, its capital cost is site dependent, which is a function of several key parameters such as geographical location, geological conditions, reservoir volume or dam requirements, generating station, resettlement, road access, transmission access as well as environmental and social impact management.
2. The economic life of a hydroelectric power station is assumed to be 50 years.
3. The lead time for Baynes, Okavango River and Lower Orange River would be ten, six and six years respectively. The expected construction time for the three stations would be seven, three and three years respectively.
4. The availability of a hydroelectric power station could be very high (taking away the forced outage and planned maintenance) if the availability of water is not taken into account.
5. The daily production profile of the run-of-river projects is dependent on water in-flows and daily peaking storage. Without a daily peaking storage, the station's output is totally dependent on its in-flows. It generates power when water flows and stops if there is no water. With a daily peaking storage, the water could be stored when the system demand is low and the station generates when the system demand is high.
6. Similar to the explanation for the daily production profile, the seasonal production would be controlled if there is a relatively large reservoir. A small reservoir such as daily peaking storage would have little control of the station's seasonal output. As per the average in-flows analysed for the Baynes power plant, the in-flows in summer (wet) months are relatively high while they are very low in winter (dry) months.
7. The EPC costs for the hydroelectric stations are based on the assumption that the EPC contracts would be awarded to experienced companies from developing economies as they normally offer much lower prices than those from developed economies.
8. The EPC costs for Baynes, Okavango River and Lower Orange River power stations were estimated at US$ 2,330 (N$ 37,280) per net unit capacity (kW), US$ 2,500 (N$ 40,000) and US$ 2,500 (N$ 40,000) respectively. These costs do not include the funds required for road access and transmission connection. The cost estimates are based on

the fact that Baynes station would have a seasonal reservoir constructed, Okavango River station would need a large amount of funds for environmental management and the Lower Orange stations would need construction of canals and tunnels.

9. Owner's cost has been estimated at 5% of the total EPC cost.
10. The construction time for the Baynes station would be some seven years, with a cash disbursement of 5%, 10%, 15%, 20%, 20%, 20% and 10%. The construction time for the other two stations would be some three years, with a cash disbursement of 30%, 40% and 30%. In order to align the capital expenditure to the in-service date, the base discount rate is used to calculate the interest during construction (IDC).
11. 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
12. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
13. Fixed O&M cost was calculated based on 1.5% of the EPC cost.
14. Variable O&M cost was assumed as N$ 80 per MWh.

4.2.6 Other Renewable Power

The Namibian Government in general, and NamPower in particular, through the establishment of a dedicated Renewable Energy Division, have recognised the importance of having renewable energy as an important part of the country's generation portfolio. However, renewable power generation should be capable of being integrated into the national grid in a cost effective and sustainable way giving careful consideration to the intermittent nature of the generation by some renewable generation technologies.

The potential of solar, wind and biomass (encroacher bush, firewood and wood charcoal) in Namibia is substantial. As per market evolution, the costs of the three renewable generation options are becoming very competitive to the conventional generation technologies.

In addition to the existing renewable based generation projects (Innosun 4.5 MW solar PV, HopSol 5 MW solar PV, one small wind generator around 220 kW near Walvis Bay, the 250 kW CBEND biomass project using gasification of encroacher bush as well as several hybrid systems at Gam, Tsumkwe and Gobabeb), commitments have been made to add the following renewable power projects within next one or two years:

1. NamPower 70 MW REFIT program
2. Diaz 44 MW wind
3. NamPower 37 MW solar PV
4. GreeNam 20 MW solar PV

Since solar power is localised and the output of the plant can be relatively accurately predicted, regional cooperation is not required beyond the possible exchange of knowledge, best practices and experience among SADC countries. Wind power, however, requires a higher level of regional co-operation since wind profiles are difficult to predict.

Wind Power Generation

The Namibian west coast has good wind resources, with annual average wind speeds ranging from 6 to 12 meters per second with a potential capacity factor from 30% to 40%, which of course depends on the wind turbine technology and tower height. There is little doubt that areas of Namibia are well suited to produce electricity from wind energy, but the potential maximum capacity is debatable. It is generally recognised that wind power is a valuable addition to a country's electricity generation mix. The level of renewable power which the Namibian grid could accommodate can be examined through a renewable power integration study. It is important to note that there is no general rule of thumb on a higher level of renewable power integration as it is subject to many factors such as load variation patterns, renewable power generation patterns, technical characteristics of the generation fleet, energy storing capability, interconnection strength and power interchange rules/policies with neighboring utilities, etc.

According to an investigation and pre-feasibility study conducted in 1996/1997 by MME, the Lüderitz area has one of the best potentials to develop a sizeable wind farm with total potential capacity of up 65 MW. The other area with great potential for wind power generation is Oranjemund, which is located in the southern part of the country and has an average wind speed of up to 10 meters per second. This area has a total potential capacity of approximately 15 MW.

The Walvis Bay area has also been identified as having considerable wind potential, with average wind speeds ranging from 7 to 12 meters per second and an estimated total potential capacity of 25 MW. The north corridor between Walvis Bay and Henties Bay has considerable wind potential for power generation. This could be extended further north from Henties Bay to Terrace Bay, and even up to Möwe Bay located further north. However, these areas need further investigation to determine their full potential. Nevertheless, the information obtained from the National Weather Service and supported by the Namibia wind map indicates that the wind regime along this section is between 7 and 10 meters per second, which is still attractive for wind power generation. The total potential of the Walvis Bay corridor up to Möwe Bay could reach 45 MW.

As per the information from the ECB, only one wind power project (Lüderitz 44 MW) currently has an effective license issued by the ECB. It is also noted that two wind power licenses lapsed. Table 4-6 summarises the technical and economic parameters for a typical 50 MW wind power project, which could be a combination of several smaller projects. The following provide simple explanations for these parameters:

1. The lead time would be from three to five years depending on permitting requirements, including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
2. It is expected that the equivalent availability of the projects would be around 95%.
3. Due to the lack of viable storage capacity, it is expected that the wind power will be variably dispatched as wind energy is available.
4. The EPC cost for the wind project is estimated at US$ 1,500 (N$ 24,000) per net unit of capacity (kW). The estimate does not include land acquisitions and interconnection to grid.

5. Owner's cost has been estimated at 5% of the total EPC cost.
6. The construction time would be approximately two years with an annual cash disbursement flow of 60% and 40%.
7. 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
8. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 2.5% of the EPC cost.
10. Variable O&M cost was estimated at N$ 80 per MWh.

Solar PV Power Generation

There are a number of different solar PV power technologies in the market, but they operate on the same principle that involves the utilisation of irradiance from the sun for producing electricity using solar panels. Due to the low voltage of an individual solar cell, several cells are wired in series in the manufacture of a "laminate". The laminate is assembled into a protective weatherproof enclosure, thus making a photovoltaic module or solar panel. Modules are then strung together into a photovoltaic array. Most PV arrays use an inverter to convert the DC power produced by the modules into AC power that can be transmitted via transmission or distribution systems to load centres to meet electricity demands.

The most common solar panel technologies on the market today are crystalline silicon modules, and thin-film modules. Sun tracking technology is available and can be implemented to improve the overall energy conversion efficiencies of a solar PV project. Trackers and sensors that optimise the performance are often seen as optional, and tracking systems can increase output by up to 50%.

Solar PV power projects can produce significant amounts of electricity ranging from a few kW to several MW and the technology is mature. Within the Namibian context, solar PV power projects can be effectively integrated into the power portfolio. The energy from the solar resource is available and free. Typically power production is higher at mid-day than the morning and afternoon, with no production at night, and tends to match well with diurnal demand profiles.

Relatively high initial capital investment and sizeable areas for the installation of solar PV projects are required. The direct costs of generation using this technology are currently very competitive to the conventional generation options. Namibia has an excellent resource and environment for large scale electricity generation from solar PV power.

Namibia has one of the highest solar radiation regimes in Africa and the world. Sunshine is available throughout the year and there are minimal interruptions even during the rainy season. The radiation is utilised by solar panels of a photovoltaic energy conversion technology, i.e. the conversion of light into electricity. This is achieved through photovoltaic (PV) modules. Namibia has promoted solar energy for many years, focusing on providing households, rural clinics, rural schools, community centers and churches with lighting and other important electrical applications. Namibia has excellent sites for large scale solar PV plants of a variety of capacities, especially in areas where there are vast tracks of open, sunny land.

Generation of electricity from solar energy is therefore enjoying support from government and the private sector. As per the information available, solar PV is increasingly paling a more important role in Namibia's electricity supply. For large-scale solar PV projects (10 MW or higher) in Namibia, the expected annual capacity factor could be in the range from 25% to 35%, with appropriate tracking system and over build of the DC side.

There are several solar PV projects with generator license issued by the ECB. It is assumed that these projects have similar technical and economic parameters as presented in Table 4-7. The following notes provide simple explanations for these parameters:

1. The lead time would be from less than one to two years depending on permitting requirements, including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
2. It is expected that the equivalent availability of the projects would be around 95%.
3. Due to the lack of viable storage capacity, it is expected that the solar PV power will be dispatched as sun light is available.
4. The EPC cost for the solar PV project is estimated at US$ 1,300 (N$ 20,800) per net unit capacity (kW_p). These estimates do not include land acquisitions.
5. The estimated EPC costs include a 20% overbuild on the DC (direct current) side. For example, a 10 MW AC (alternating current) system will have a 10 MW inverter capacity but 12 MW of DC capacity.
6. Owner's cost has been estimated at 5% of the total EPC cost.
7. The construction time would generally be approximately two years with an annual cash disbursement flow of 60% and 40% (although there could be cases of construction time being less than a year) 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
8. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 2.5% of the EPC cost.
10. Variable O&M cost was estimated at N$ 80 per MWh.

Concentrated Solar Power Generation

Concentrated solar power (CSP), also referred to as solar thermal power, involves the utilisation of the sun's heat for power generation. CSP is being widely commercialised and the CSP market has been growing over the last several years. There are a number of different technologies on the market, but they operate on the same principle. Solar heat is trapped and concentrated by mirrors and reflected onto a heat-transfer medium (gas or liquid) contained in pipes. This medium then transfers the heat to water, producing steam, which drives a turbine. CSP stations can produce significant amounts of electricity ranging from a few MW to several hundred MW and they, through heat storage mechanisms (such as salt reservoirs) can produce electricity, albeit at a reduced capacity, for almost 24 hours.

Within a Namibian context, CSP stations are potential candidates for integration into the national grid together with other generation technologies. Namibia, south from Mariental, is generally considered to be highly suitable for CSP power generation.

CSP sun heat collectors for electricity generation require a large amount of initial capital investment and large surface areas for the installation of the solar heat collectors. With ongoing decreases in capital investment cost, this technology could be more readily available and affordable in the near future. Namibia has one of the best environments for installation of CSP collectors for large scale electricity generation.

1. It is noted that NamPower intends to issue a tender for the Techno-Economic Advisor for the Feasibility Study of the Concentrated Solar Power Project with an estimated budget of EUR 1,100,000.
2. The estimated technical and economic parameters for CSP plants are summarised in Table 4-8. The following notes provide high-level explanations for these parameters:
   i) Only one size of CSP, 50 MW is selected for this study. The size could be changed based on the future study results. However, four options, i.e. no storage, 4-hour storage, 8-hour storage and 12-hour storage are selected.
   ii) The lead time would be from five to six years including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
   iii) It is expected that the equivalent availability of a unit would be around 90%. Due to the limited energy and storage capacity, it is expected that most energy will be dispatched during day time and/or evening hours when the system experiences its daily high load demand.
   iv) The EPC costs for the four options are estimated at US$ 1,800 (N$ 28,800) per net unit of capacity (kW). US$ 2,500 (N$ 40,000), US$ 3,750 (N$ 60,000) and US$ 5,000 (N$ 80,000) respectively. These estimates exclude land acquisitions.
   v) Owner's cost has been estimated at 10% of the total EPC cost.
   vi) The construction time would be some three years, with a cash disbursement of 30%, 40% and 30%.
   vii) 1% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.

viii) 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.

ix) Fixed O&M cost was calculated based on 3% of the unit's EPC cost.

x) Variable O&M cost was assumed as N$160 per MWh.

Biomass

Namibia has abundant biomass resources in the form of encroacher bush, which is located primarily in the north-central and central regions. It has been estimated that there are approximately 26 million hectares of bush-encroached land in Namibia. Encroacher bush prevents the growth of useful grass species, resulting in the compaction of soils in the bush encroached areas. It has reduced Namibia's carrying capacity of livestock, leading to reduced cattle numbers over the past 50 years - from 2.5 million in the commercial farming areas down to some 800,000 head of cattle. According to studies, the reduced availability of land for grazing causes economic losses exceeding one billion Namibian dollars in the agricultural sector every year. Another worrying factor is that the extensive root network - up to 40 meters long - of some encroacher bush species robs the soil of moisture. Soil also gets compacted, which prevents rainwater from penetrating the soil and replenishing the underground water table.

It appears that encroacher bush represents a nearly unlimited resource with which to generate electricity. Use of the encroacher bush for energy production is assumed to have excellent side benefits such as increased water infiltration, increased biodiversity, and improved business and employment opportunities in the agricultural sector. The scale of biomass combustion power plants typically varies from 5 MW to 50 MW, but smaller plant sizes are also possible.

Assuming a 60% sustainable bush clearing approach and a production rate of 12 tonnes per hectare, some 36,000 tonnes of bush chip for power production can be considered realistic in a bush encroached farming unit of 5,000 hectares, which is enough to fuel a 5 MW unit for one year. This calculation is based on a heating value of 16 GJ per tonne, heat rate of 15 GJ per MWh and plant utilisation factor of 80%. Without taking into account bush harvesting cycle, a 5 MW biomass plant would need 25 average-sized farms over its economic life of 25 years. For understanding of the harvesting area, a circle with a radius of 22 km will cover the total area of 25 farms. It is important to highlight that the bush should be harvested in a sustainable manner to be of real benefit to the environment.

The Combating Bush Encroachment for Namibia's Development (CBEND) initiative is a proof-of-concept project implemented by the Desert Research Foundation of Namibia (DRFN) in partnership with the Namibia Agricultural Union and the Namibia National Farmers Union and funded by the European Commission at an amount of N$ 14 million through the National Planning Commission Secretariat's Rural Poverty Reduction Programme.

The CBEND Project has installed a 250 kW bush-to-electricity power plant on a commercial farm (in one of the most bush infested areas) in the Outjo area in Namibia, which is fueled with encroacher bush and will feed electricity directly into the national grid. This demonstration project is Namibia's first independent power producer and could be used to assess the financial feasibility of this approach and evaluate the technical robustness of the technology. Unfortunately the project has faced various challenges and has not yet commenced commercial operation.

The Support to De-bushing Project is a bilateral cooperation between the Namibia Ministry of Agriculture, Water and Forestry and the German Federal Ministry for Economic Cooperation and Development, which runs from 2014 to 2017, being implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit GmbH. The Project is aimed to strengthen the restoration of productive rangeland in Namibia. The Project has investigated several methods to economically harvest encroacher bush.

Table 4-9 provides a summary of the estimated technical and economic parameters for the encroacher bush fired power projects, while the following provide additional explanations on these parameters:

1. The bubbling fluidised bed (BFB) technology is selected for the encroacher bush power plants with size of either 5 MW or 10 MW.
2. The lead time would be three to five years including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
3. It is expected that the equivalent availability of a unit would be approximately 88%.
4. The EPC costs for the 5 MW and 10 MW projects are estimated at US$ 4,000 (N$ 64,000) per net unit capacity (kW) and US$ 3,800 (N$ 60,800) respectively. It is expected that more accurate estimates on capital investment, fuel cost and O&M cost of a biomass plant would be provided by a study to be undertaken by NamPower[5].
5. Owner's cost has been estimated at 5% of the total EPC cost.
6. The construction time would be some three years, with a cash disbursement of 30%, 40% and 30%.
7. 1% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
8. 1% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 2.5% of the unit's EPC cost.
10. Variable O&M cost was estimated at N$ 320 and N$ 240 per MWh for the two different unit sizes.

4.3 Imports from SAPP

It is learned from NamPower that discussions have been held with several entities to address the possibility of these entities supplying power to Namibia under fixed duration and fixed term conditions. The table below shows the source/entity as well as its fuel to be used, amount of capacity, price and earliest possible in-service date for several power import options:

[5] NamPower, through the European Investment Bank, has issued a tender for the Techno-Economic Advisor for the Feasibility Study of the Encroacher Bush Biomass Power Plant

Source/Entity	Country	Fuel	Import Capacity (MW)	Cost (N$/MWh)	Earliest Date
ZPC	Zambia		50	2,224	2016
Lunsemfwa (IPP)	Zambia	Hydro	50	1,776	2017/08
	Mozambique		100	2,640	2017
IPP	Botswana		200	2,272	2017

As previously mentioned, sources located outside Namibia would not qualify as Internal Resources regardless of type of participation (including ownership) to meet the requirements outlined in the 1998 Energy White Paper for both capacity and energy contributions.

4.4 Secondary Generation Options with Quantified Resources but Non-mature Technology

This section provides a brief description of the options with quantified resources but non mature technologies (including small nuclear reactors).

4.4.1 Small Modular Nuclear Reactor Power Generation

Due partly to the high capital cost of large nuclear reactors generating electricity via the steam cycle and partly to the need to service small electricity grids under about 4,000 MW, there is a move to develop smaller nuclear power units. These may be built independently or as modules in a larger complex, with capacity added incrementally as required. There are also moves to develop small units for remote sites. Small units are seen as a much more manageable investment than big ones whose cost rivals the capitalisation of the utilities concerned.

The four 12 MW EGP-6 nuclear reactors located in the Bilibino nuclear power plant, Chukotka Autonomous Okrug, Russia, are the smallest and the northernmost operating nuclear power units in the world. The EGP-6 reactors are a scaled down version of the RBMK reactor design. Notably, these reactors along with the RBMK designs are some of the few active reactors which still use light water cooled graphite as a neutron moderator. It is noted that construction of the plant began in 1966 and the first two units started operation in 1973, the third one in 1975 and the last one in 1976. Under the International Nuclear Safety Program, the U.S. Department of Energy (DOE) assisted with safety improvements at Bilibino NPP, particularly focusing on improving the safety of day-to-day operations. Activities included an analytical simulator project, safety and maintenance training, and the provision of monitoring and communications equipment, among others.

The RBMK is an early Generation II reactor and the oldest commercial reactor design still in wide operation. It features a number of design and safety flaws (such as graphite-tipped control rods, a dangerous positive void coefficient and instability at low power levels) that have since been rectified in newer designs. The reactor's flaws contributed to the 1986 Chernobyl disaster in which an RBMK exploded during an unsafe test and spread radioactivity over a large portion of Eastern Europe. The disaster prompted worldwide calls for the reactors to be completely decommissioned, although there is still considerable reliance on RBMK facilities for power in Russia and the post-Soviet republics. The last RBMK at Chernobyl was not shut down until 2000, and as of 2010 there were still at least 11 RBMK reactors operating in Russia alone.

In 2007, the Government of Namibia, through the MME, identified nuclear energy as an option to be considered for electricity generation, which has resulted in interest from foreign investors. A series of discussions/negotiations between the Namibian and Russian governments took place from mid-2007 for the development of a nuclear power plant with 50 MW units to be located offshore Namibia. There are, however, serious concerns related to the safety and environmental risks of the proposed floating nuclear power plant technology as it is a new technology which has not been commercially available and has not been used in other countries. On the other hand, a French company has been investigating the possibilities for investing in nuclear power generation in Namibia based on the technology that has been proven to be technologically sound in developed countries.

In early 2012, the DOE announced its first step toward manufacturing small modular nuclear reactors (SMRs) in the United States. Through the draft Funding Opportunity Announcement (FOA), the Department will establish cost-shared agreements with private industry to support the design and licensing of SMRs. The draft FOA is a working document soliciting input from industry to promote leading edge design certification, licensing and engineering.

It is suggested that the small nuclear reactor power generation could be taken into account in the future NIRP development only when they are commercially available and technically proven. The lead time should, of course, include all necessary components for a nuclear power plant, including requirements for personnel training, establishment of national nuclear regulatory commission and associated laws, regulations and codes, feasibility study, environmental and social impact assessment, construction and commissioning.

Table 4-10 summarises the technical and economic parameters estimated for the small modular nuclear reactors which could be applicable to the Namibia electric system in the future. The following are some additional notes to this table:

1. The lead time for a small modular nuclear power plant could be from six to eight years following the approval and commercialisation of the reactors.
2. The earliest on-line time of a SMR is subject to future technology development and commercialisation.
3. It is expected that the equivalent availability of a nuclear plant would be around 88%, based on the information from the NERC database. Its capacity factor could, therefore, be only up to this value as the plant might not produce at its full capacity at all times due to various reasons such as low load demand, contribution to spinning reserve obligation, etc.
4. The EPC costs for 50 MW and 100 MW have been estimated at US$ 9,000 (N$ 144,000) per net unit capacity (kW), and US$ 8,500 (N$ 136,000) respectively.
5. Owner's cost has been estimated at 5% of the total EPC cost.
6. The construction time for a small modular nuclear unit would be some four years, with a cash disbursement of 15%, 35%, 35%, and 15%. In order to align the capital expenditure to the in-service date, the base discount rate is used to calculate the interest during construction (IDC).
7. 0.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.

8. 1% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 1.5% of the unit's EPC cost.
10. Variable O&M cost was estimated at N$ 240 per MWh for the two size units.

4.5 Secondary Generation Options with Mature Technology but Non-quantified Resources

This section provides a brief description of the options with mature technology but non-quantified resources which we consider to include wind power generation, solar PV power generation, solar thermal power generation, generation using municipal solid waste, bio-fuels, biomass and geothermal generation.

4.5.1 Wind Power Generation

There are a number of different wind power technologies on the market, but they operate on the same principle that involves the conversion of the kinetic energy in the wind to produce electricity using wind turbine-generators. The most common technology on the market today is the horizontal axis wind turbine (HAWT). The HAWTs have a rotor and a nacelle that houses the main rotor shaft and electrical generator at the top of a tower. Computer controlled yaw motors and pitch mechanisms allow the nacelle to turn and pitch with changes in wind direction. Most have a gearbox, which controls the rotational speed of the blades and many new models are available with direct drive systems that eliminate the need for a gearbox.

Turbines used in wind power plants for commercial production of electric power are usually three-bladed with high tip speeds of up to 320 km per hour, high efficiency, and low torque ripple, which contribute to reasonable reliability. The blades are usually colored light gray to blend in with the clouds and range in length from 20 to 50+ metres. The tubular steel towers range from 50 to 100+ metres tall. Modern technologies are equipped with protective features to avoid damage at high wind speeds, by feathering the blades into the wind which ceases their rotation, supplemented by brakes.

A wind power plant can produce significant amounts of electricity ranging from a few MW to few hundred MW and the technology is mature. Within the Namibian context, wind power projects can be effectively integrated into the power portfolio. The energy from the wind resource is available and free, but highly variable. As a result, the transmission and distribution system operator must consider regulation measures using other dispatchable quick response generating stations to deliver power to meet firm demand requirements.

Relatively high initial capital investment and large areas for the installation of the wind turbines are required. This could make this technology less affordable and accessible currently, but with possible further increases in the price of fossil fuels, and the need for safer and cleaner energy sources, the cost of wind power technology could keep on decreasing and make these technologies readily available and affordable in the near future. Namibia has potential for large scale electricity generation from wind power.

It is expected that the following essential steps are required to quantify wind resources at a reasonably accurate level:

1. Review of previous and current studies on wind energy potentials, wind resource data monitoring campaigns, and critical assessment of the available data.
2. Based on the review work of the previous studies, select four to eight representative sites for wind resource monitoring and assessment.
3. Installation of monitoring equipment at the selected sites and collection of required data for at least one year and analysis of the data collected.
4. Wind power plant site selection will require detailed wind resource maps, and transmission and distribution maps.
5. Carry out prefeasibility studies for the selected sites to estimate the potential output, required investment and O&M costs.
6. The total period for this resource quantification would be two years or longer.
7. The total funds required for this could be from US$ 500,000 (N$ 8,000,000) to US$ 1,000,000 (N$ 16,000,000) but it is dependent on the level of accuracy, degree of complexity, size of the project, and requirements of the wind monitoring campaign.

It is noted that there are a couple of wind power projects with lapsed conditional licenses from ECB. It is not clear at this point the extent to which the developers have completed the above steps.

The technical and economic parameters of a wind power plant with a size ranging from 30 to 100 MW have been presented in Table 4-6.

4.5.2 Power Generation Using Municipal Solid Waste

Electricity can be produced by burning municipal solid waste (MSW) as a fuel. MSW power plants, also called waste to energy (WTE) plants, are designed to dispose of MSW and to produce electricity as a byproduct of the incinerator operation. The term MSW describes the stream of solid waste generated by households and apartments, commercial establishments, industries and institutions. MSW consists of everyday items such as product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, paint and batteries. It does not include medical, commercial and industrial hazardous or radioactive wastes, which must be treated separately.

MSW is managed by a combination of disposal in landfill sites, recycling, and incineration. MSW incinerators often produce electricity in WTE plants. The U. S. EPA recommends, "The most environmentally sound management of MSW is achieved when these approaches are implemented according to EPA's preferred order: source reduction first, recycling and composting second, and disposal in landfills or waste combustors last.

In the United States, there are currently two main WTE facility designs:

- Mass Burn is the most common waste-to-energy technology, in which MSW is combusted directly in much the same way as fossil fuels are used in other direct combustion technologies. Burning MSW converts water to steam to drive a turbine connected to an electricity generator.
- Refuse-derived fuel (RDF) facilities process the MSW prior to direct combustion. The level of pre-combustion processing varies among facilities, but generally involves

shredding of the MSW and removal of metals and other bulky items. The shredded MSW is then used as fuel in the same manner as at mass burn plants.

In addition to the two main WTE facilities designs mentioned above, there are also two other technologies, pyrolysis and thermal gasification, under the development stage with a limited number of units in operation. Pyrolysis and thermal gasification are related technologies. Pyrolysis is the thermal decomposition of organic material at elevated temperatures in the absence of gases such as air or oxygen. The process, which requires heat, produces a mixture of combustible gases (primarily methane, complex hydrocarbons, hydrogen and carbon monoxide), liquids and solid residues.

Thermal gasification of MSW is different from pyrolysis in that the thermal decomposition takes place in the presence of a limited amount of oxygen or air. The producer gas which is generated can then be used in either boilers or cleaned up and used in combustion turbine/generators. The primary area of research for this technology is the scrubbing of the producer gas of tars and particulates at high temperatures in order to protect combustion equipment downstream of the gasifier and still maintain high thermal efficiency.

A couple of technologies for generating electricity using MSW are well developed internationally. Namibia could not support large MSW generation facilities as it only has modest amounts of waste resources available with which to generate electricity due to its relatively low population. A study performed by Stewart and Scott in 1997 indicated that Windhoek did not generate sufficient amounts of refuse to support an economically sized power plant.

There are, however, small scale technologies available that are able to generate electricity from refuse, in particular those based on gasification. Due to the relatively small size of these technologies, it is possible that they could be applied in Namibia's medium-sized towns. However, it should be emphasised that refuse gasification technologies have not been fully proven internationally.

It is expected that the following essential steps are required to quantify municipal solid waste plants at a reasonably accurate level:

1. Review of previous studies on solid waste energy, collection of the current MSW disposal quantity, critical assessment of the available data and selection of several of the larger cities for potential MSW power plants, each with a capacity of some 10 MW or 20 MW.
2. Analysis of the MSW samples for each selected city and assessment of the energy available to fuel a power plant.
3. Carry out prefeasibility study for the selected sites to estimate the potential output, required investment and O&M costs.
4. The total period for this resource quantification would be one year.
5. The total funds required for this work could be from US$ 200,000 (N$ 3,200,000) to US$ 1,000,000 (N$ 16,000,000).

The estimated technical and economic parameters for the MSW power plants are summarised in Table 4-11. The following notes provide simple additions to these parameters:

1. Two sizes, 10 MW and 20 MW are selected for this study. They could be changed based on the future study results.
2. The lead time would be from five to seven years including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
3. It is expected that the equivalent availability of a unit would be around 80%.
4. The EPC costs for the 10 MW and 20 MW plants are estimated at US$ 8,000 (N$ 128,000) per net unit of capacity (kW) and US$ 7,500 (N$ 120,000) respectively.
5. Owner's cost has been estimated at 5% of the total EPC cost.
6. The construction time would be some three years, with a cash disbursement of 30%, 40% and 30%.
7. 0.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
8. 1% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 2% of the unit's EPC cost.
10. Variable O&M costs were assumed as N$ 320 per MWh.

4.5.3 Bio-fuels Power Generation

Namibia also has a potential for bio-fuel production. The viability of bio-fuel production will depend on the prices of both electricity and liquid fuels. It is expected that the following essential steps are required to quantify bio-fuels at a reasonably accurate level:

1. Review of previous studies on bio-fuels, particularly the Okavango Bio-Fuel project, collection of the information related to the bio-fuel resources, critical assessment of the available data and selection of one to two sites for potential bio-fuel power plants. As CCGT could use bio-fuels as fuel, it is suggested that CCGT should be used and each CCGT plant could have a capacity of either 75 MW (two 25 MW GTs and one 25 MW ST) or 150 MW (two 50 MW GTs and one 50 MW ST).
2. Collection of crop samples and analysis of bio-fuel production rates.
3. Analysis of the potential bio-fuel resources and estimate of the total bio-fuels available to each selected site to fuel a power plant.
4. Carry out prefeasibility study for the selected sites to estimate the potential output, required investment and O&M costs.
5. The total period for this resource quantification would be one year.
6. The total funds required for this work could be from US$ 200,000 (N$ 3,200,000) to US$ 500,000 (N$ 8,000,000).

7. The estimated technical and economic parameters for the bio-fuel power plants are summarised in Table 4-12. The following notes provide simple explanations on these parameters:

1. Two CCGT sizes, 75 MW and 150 MW are selected for this study. They could be revised based on the future study results.
2. The lead time would be from six to seven years including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
3. It is expected that the equivalent availability of a unit would be around 88%.
4. The EPC costs for the 75 MW and 150 MW are estimated at US $900 (N$ 14,400) per net unit of capacity (kW) and US$ 850 (N$ 13,600) respectively.
5. Owner's cost has been estimated at 10% of the total EPC cost.
6. The construction time would be some three years, with a cash disbursement of 30%, 40% and 30%.
7. 1.5% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
8. 2% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
9. Fixed O&M cost was calculated based on 3% of the unit's EPC cost.
10. Variable O&M cost was assumed as N$ 240 per MWh.

4.5.4 Geothermal Power Generation

In 2004, the University of the Witwatersrand advised the Namibian Geological Survey on aspects of terrestrial heat flow and the potential of geothermal energy in Namibia. Heat flow maps of Namibia and the region surrounding Namibia would suggest that the potential is high compared with most of the rest of the subcontinent, but there are large areas, particularly in the west where there is little information. There are only 12 heat flow measurements in Namibia, mostly from the Damara Belt, and this and the scarcity of data in adjacent regions results in an incomplete heat flow pattern. The average heat flow for the Damara Belt (69±10mW m^{-2}) is the highest in the region but the heat flow does not attain the extremely high values observed in geologically more active regions. The high heat flow is not associated with thermal transients and is probably due to an enhanced radioactive contribution from the upper crust.

Despite the relatively high heat flow, the thermal gradients are not exceptionally high and exceed 25 K km^{-1} at only three localities. Regional subsurface temperature maps obtained by one dimensional modeling of the heat flow data indicate that temperatures exceeding 100°C are only reached at 2 – 3 km. This modeling is preliminary and a detailed analysis, based on more complete heat flow coverage and variations in geological structure may reveal local temperature anomalies.

Hot water or thermal springs in Namibia are known in Warmbad, Rehoboth, Omburo (near Omaruru) and Gross Barmen (near Okahandja). These are used for recreational and tourism purposes. The occurrence of thermal springs has possible implications for geothermal energy. Those at Windhoek and Omburo are of particular interest as the temperatures of the surface waters were originally 70 - 80°C. These temperatures are however lower than those observed in active geological regions and the origins of the springs appear to be heating of meteoric water under the normal geothermal gradient. Preliminary calculations indicate that the springs probably rise from depths of 2 – 3 km. Drilling into the springs at Grosse Windhoek in the 1920s caused them to dry up, so the recharge rate of the springs is also of concern. These comments are based on little information and more work is required to establish the depth, size and temperature of the reservoirs giving rise to the springs and whether the rainfall and permeability of the aquifers feeding the reservoirs are sufficient to recharge them.

Currently there is insufficient data relating to geothermal gradients, heat flow patterns and other information relating to hot spring reservoirs to make a sound scientific assessment of the geothermal potential. This would be possible if there were a better coverage of heat flow data and more in-depth knowledge of thermal springs based on scientific investigations.

Reconnaissance level heat flow coverage over the entire country would be desirable and this would take at least two years to achieve because heat flow determination is time consuming. Particular attention should also be paid to the following: (i) areas where hot springs exist, especially Windhoek and Omburo, (ii) sedimentary basins such as the Owambo and Nama Basins, where deep-seated aquifers might house geothermal reservoirs Opportunities for heat flow determination include (i) making use of commercial offshore heat flow measurements and bottom hole temperature measurements in offshore and onshore oil wells which would require collaboration with the Namibian Petroleum Corporation, (ii) conducting surveys in mineral exploration boreholes and stratigraphic holes that might be drilled by the Geological Survey, (iii) collaborating with the Department of Water Affairs which conducts routine geophysical surveys in water exploration wells.

Further investigations of the hot springs in Windhoek and Omburo should be aimed at establishing the depth and extent of the reservoirs, their temperatures and water content and the recharge rates. A first step towards determining the temperature would be to survey some boreholes into the Windhoek springs that are currently being planned by the Windhoek Municipality. It may also be worth collaborating with the Municipality with a view to having one of these holes deepened. If the permeability of the reservoirs and the aquifers feeding them and the rainfall in the catchment areas are found to be inadequate to recharge the reservoirs, the use of artificial methods of enhancing these parameters (including hydraulic fracturing and injection of waste water) should be investigated. Finally, if the temperatures of the reservoirs are not high enough to use conventional turbines, the viability of binary-cycle turbines, which can operate at temperatures as low as 85°C, should be investigated.

Considerable Government engagement would be required to finance, coordinate and evaluate the research as suggested above. Should sufficient data be obtained to ascertain the availability of sustainable geothermal energy, the Government of Namibia would be advised to support investments in geothermal electricity generating plants. Geothermal electric plants have relatively modest installation capital costs. Such plants could therefore be funded through a government-private sector initiative or by an IPP. Once running, the only major running cost of such electric plants is maintenance of the hot water pipes and the steam turbines. If appropriate corrosion prevention methods are incorporated at the design stage, the cost of maintenance becomes minimal.

Based on the success of existing geothermal electric plants in Naivasha Kenya, one could foresee a scenario in which Namibia would establish several generating plants in the future if sustainable geothermal energy sources are confirmed. Such electric plants would then be connected to the national grid and provide a clean, affordable and environmentally friendly energy source. With such a scenario, regional and international cooperation is not critical because power generation from geothermal plants can be varied or even shut down in times of excess power in the grid.

It is expected that the following essential steps are required to quantify the geothermal resources at a reasonably accurate level:

1. Review of previous studies on geothermal resources, collection of the information related to the geothermal energy resources, critical assessment of the available data and selection of two to five sites for potential geothermal power plants.
2. Investigation of the geothermal potential for each of the selected sites through reconnaissance, drill, testing, etc.
3. Analysis of the potential geothermal resources and estimate of the total resources available to each selected site to fuel a power plant.
4. Carry out prefeasibility study for the selected sites to estimate the potential output, required investment and O&M costs.
5. The total period for this resource quantification would be two to four years.
6. The total funds required for this work could be from US$ 1,000,000 (N$ 16,000,000) to US$ 3,000,000 (N$ 48,000,000).

7. The estimated technical and economic parameters for the geothermal power plants are summarised in Table 4-13. The following notes provide abbreviated explanations on these parameters:

    1. Two plant sizes, 5 MW and 20 MW are selected for this study. They could be revised based on the resources available.
    2. The lead time would be from eight to ten years including resource quantification, scoping study, feasibility study, EPC contract document preparation as well as tendering and awarding, financing closure, construction and commissioning.
    3. It is expected that the equivalent availability of a plant would be approximately 86%.
    4. The EPC costs for the 5 MW and 20 MW are estimated at US$ 6,500 (N$ 104,000) per net unit of capacity (kW) and US$ 6,000 (N$ 96,000) respectively.
    5. Owner's cost has been estimated at 5% of the total EPC cost.
    6. The construction time would be some three years, with a cash disbursement of 30%, 40% and 30%.
    7. 1% of the sum of EPC, owner's cost and IDC is assumed to be the financing charges including commitment fees.
    8. 1% of the sum of EPC, owner's cost and IDC is assumed to be the decommissioning costs, which is allocated at the beginning of the unit's operation.
    9. Fixed O&M cost was calculated based on 3% of the unit's EPC cost.

10. Variable O&M cost was assumed as N$ 240 per MWh.

Table 4-1: Coal Fired Power Generation

Generation Technology		CFB	PC	Comment
Fuel		Coal		
Plant Gross Capacity (MW)		168	162	
Plant Net Capacity (MW)		150	150	
Number of Units		1	1	
Economic Life (Year)		30	30	
Lead Time (Year)		6-7	6-7	
Earliest On-Line Year		2021/2022	2021/2022	
Equivalent Availability (%)		85	85	Based on NERC database
Equivalent Forced Outage Rate (%)		7.0	7.0	
Planed Outage Rate (%)		8.0	8.0	Four weeks per year
Production Profile (Daily)		Dispatched as per system requirements		
Production Profile (Seasonal)		Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)		11,600	11,000	
Primary Fuel Cost ($/GJ)		40.16	40.16	
Overall Capitalized Cost ($M)		6,302.6	5,670.4	
	Plant EPC ($M)	4,080.0	3,600.0	Based on net capacity
	Owner's Cost ($M)	408.0	360.0	10% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		
	Plant IDC ($M)	703.9	621.1	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	734.0	734.0	
	Owner's Cost for Grid Integration ($M)	73.4	73.4	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	
	Grid Integration IDC ($M)	90.2	90.2	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	91.3	82.2	1.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)			
	Decommissioning Cost ($M)	121.8	109.6	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		42,018	37,803	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		816.0	720.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		320.0	320.0	
CO2 Emission Rate (kg/GJ)		87.970	87.970	Uncontrolled factors calculated as per the parameters from the US EIA and EPA. About 90% of NOx could be reduced by GT. SO2 emission factor was calculated based on 1% sulphur content.
NOx Emission Rate (kg/GJ)		0.089151	0.21396	
SO2 Emission Rate (kg/GJ)		0.067755	0.67755	
Particulate Matter Emission Rate (kg/GJ)		0.025679	0.02568	

Note: All Costs expressed in N$

Table 4-2: Natural Gas Fired Power Generation

Generation Technology		CCGT	CCGT	GT	GT	Comment
Fuel		Kudu Gas	LNG			
Plant Gross Capacity (MW)		452	156	51	102	
Plant Net Capacity (MW)		442	150	50	100	
Number of Units		1	1	1	1	
Economic Life (Year)		25	25	20	20	
Lead Time (Year)		3.5-4	5-6	3-4	4-5	
Earliest On-Line Year		2019/2020	2021/2022	2019/2020	2020/2021	
Equivalent Availability (%)		87	87	90	90	Based on NERC database
Equivalent Forced Outage Rate (%)		6.0	6.0	5.0	5.0	
Planed Outage Rate (%)		6.0	6.0	4.0	4.0	Three/Two weeks per year
Production Profile (Daily)		Dispatched as per system requirements				
Production Profile (Seasonal)		Dispatched as per system requirements				
Net Heat Rate (KJ/kWh, HHV)		6,968	7,488	9,690	9,384	
Primary Fuel Cost ($/GJ)		160	216	216	216	
Overall Capitalized Cost ($M)		10,617.2	3,615.8	1,006.9	1,912.5	
	Plant EPC ($M)	5,657.6	2,040.0	560.0	1,040.0	Based on net capacity
	Owner's Cost ($M)	565.8	204.0	56.0	104.0	10% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		60%, 40%		
	Plant IDC ($M)	976.0	351.9	68.8	127.8	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	2,122.0	734.0	235.5	471.0	
	Owner's Cost for Grid Integration ($M)	212.2	73.4	23.6	47.1	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		60%, 40%		
	Grid Integration IDC ($M)	260.8	90.2	28.9	57.9	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	146.9	52.4	14.6	27.7	1.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)	480.0				For Kudu gas power plant only
	Decommissioning Cost ($M)	195.9	69.9	19.5	37.0	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		24,021	24,106	20,137	19,125	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		384.0	408.0	336.0	312.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		240.0	240.0	240.0	240.0	
CO2 Emission Rate (kg/GJ)		50.101	50.101	50.101	50.101	Uncontrolled factors calculated as per the parameters from the US EIA and EPA. About 90% of NOx could be reduced by GT. SO2 emission factor was calculated based on 1% sulphur content.
NOx Emission Rate (kg/GJ)		0.140358	0.140358	0.140358	0.140358	
SO2 Emission Rate (kg/GJ)		0.000025	0.000025	0.000025	0.000025	
Particulate Matter Emission Rate (kg/GJ)		0.002821	0.002821	0.002821	0.002821	

Note: All Costs expressed in N$

Table 4-3: Fuel Oil Fired Power Generation

Generation Technology	ICRE	CCGT	GT	GT	Comment
Fuel	HFO	LFO			
Plant Gross Capacity (MW)	20.8	156	51	102	
Plant Net Capacity (MW)	20	150	50	100	
Number of Units	1	1	1	1	
Economic Life (Year)	25	25	20	20	
Lead Time (Year)	4-5	5-6	4-5	4-5	
Earliest On-Line Year	2020/2021	2021/2022	2020/2021	2020/2021	
Equivalent Availability (%)	90	87	90	90	Based on NERC database
Equivalent Forced Outage Rate (%)	5.0	6.0	5.0	5.0	
Planed Outage Rate (%)	4.0	6.0	4.0	4.0	Two/three weeks per year
Production Profile (Daily)	Dispatched as per system requirements				
Production Profile (Seasonal)	Dispatched as per system requirements				
Net Heat Rate (KJ/kWh, HHV)	8,860	7,216	9,338	9,043	
Primary Fuel Cost ($/GJ)	134.72	267.33	267.33	267.33	
Overall Capitalized Cost ($M)	600.2	3,615.8	1,006.9	1,912.5	
Plant EPC ($M)	352.0	2,040.0	560.0	1,040.0	Based on net capacity
Owner's Cost ($M)	35.2	204.0	56.0	104.0	10% of Plant's EPC cost
Plant CAPEX Disbursement Flow (%)	60%, 40%	30%, 40%, 30%	60%, 40%		
Plant IDC ($M)	43.3	351.9	68.8	127.8	Rate of 10% to align the cost to service year
Grid Integration EPC ($M)	122.2	734.0	235.5	471.0	
Owner's Cost for Grid Integration ($M)	12.2	73.4	23.6	47.1	10% of Integration cost
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		60%, 40%		
Grid Integration IDC ($M)	15.0	90.2	28.9	57.9	Rate of 10% to align the cost to service year
Financing Charges including Commitment ($M)	8.7	52.4	14.6	27.7	1.5% of sum of all EPC, Owner's cost and IDC
Commissioning Cost ($M)					For Kudu gas power plant only
Decommissioning Cost ($M)	11.6	69.9	19.5	37.0	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)	30,010	24,106	20,137	19,125	Based on the net capacity
Fixed O&M Cost ($/kW-Year)	528.0	408.0	336.0	312.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)	240.0	240.0	240.0	240.0	
CO2 Emission Rate (kg/GJ)	69.009	69.009	69.009	69.009	Uncontrolled factors calculated as per the parameters from the US EIA and EPA. About 90% of NOx could be reduced by GT. SO2 emission factor was calculated based on 1% sulphur content.
NOx Emission Rate (kg/GJ)	0.000566	0.000566	0.000566	0.000566	
SO2 Emission Rate (kg/GJ)					
Particulate Matter Emission Rate (kg/GJ)					

Note: All Costs expressed in N$

Table 4-4: Nuclear Power Generation

Generation Technology	Nuclear	Nuclear	Comment
Fuel	Uranium		
Plant Gross Capacity (MW)	224	672	
Plant Net Capacity (MW)	200	600	
Number of Units	1	1	
Economic Life (Year)	40	40	
Lead Time (Year)	20	20	
Earliest On-Line Year	2035	2035	
Equivalent Availability (%)	85	85	Based on NERC database
Equivalent Forced Outage Rate (%)	5.0	5.0	
Planed Outage Rate (%)	10.0	10.0	Five weeks per year
Production Profile (Daily)	Dispatched as per system requirements		
Production Profile (Seasonal)	Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)	10,000	10,000	
Primary Fuel Cost ($/GJ)	16	16	
Overall Capitalized Cost ($M)	44,163.9	96,286.5	
Plant EPC ($M)	25,600.0	67,200.0	Based on net capacity
Owner's Cost ($M)	1,280.0	3,360.0	5% of Plant's EPC cost
Plant CAPEX Disbursement Flow (%)	10%, 15%, 20%, 25%, 20%, 10%		
Plant IDC ($M)	8,905.9	23,378.1	Rate of 10% to align the cost to service year
Grid Integration EPC ($M) [1]	5,970.0		
Owner's Cost for Grid Integration ($M)	597.0	0.0	10% of Integration cost
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	
Grid Integration IDC ($M)	733.8	0.0	Rate of 10% to align the cost to service year
Financing Charges including Commitment ($M)	215.4	469.7	0.5% of sum of all EPC, Owner's cost and IDC
Commissioning Cost ($M)			For Kudu gas power plant only
Decommissioning Cost ($M)	861.7	1,878.8	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)	220,819	160,478	Based on the net capacity
Fixed O&M Cost ($/kW-Year)	1,920.0	1,680.0	Based on 1.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)	160.0	128.0	
CO2 Emission Rate (kg/GJ)			Not applicable
NOx Emission Rate (kg/GJ)			
SO2 Emission Rate (kg/GJ)			
Particulate Matter Emission Rate (kg/GJ)			

Note: [1] Grid connection has not been costed for the 600 MW unit because of complexity and extremely large project scope

Note: All Costs expressed in N$

Table 4-5: Hydro Electric Power Generation

Generation Technology	Baynes [1]	Okavango	Orange	Comment
Fuel	Water			
Plant Gross Capacity (MW)	306	20.4	102	
Plant Net Capacity (MW)	300	20	100	
Number of Units				
Economic Life (Year)	50	50	50	
Lead Time (Year)	10	6	6	
Earliest On-Line Year	2026	2022	2022	
Equivalent Availability (%)	90	90	90	Based on NERC database
Equivalent Forced Outage Rate (%)	4.0	4.0	4.0	
Planed Outage Rate (%)	4.0	4.0	4.0	Three/Two weeks per year
Production Profile (Daily)	Dispatched as per system requirements			
Production Profile (Seasonal)	Dispatched as per system requirements			
Net Heat Rate (KJ/kWh, HHV)				
Primary Fuel Cost ($/GJ)				
Overall Capitalized Cost ($M)	24,964.2	1,073.3	5,624.9	
Plant EPC ($M)	11,184.0	800.0	4,000.0	Based on net capacity
Owner's Cost ($M)	559.2	40.0	200.0	5% of Plant's EPC cost
Plant CAPEX Disbursement Flow (%)	Baynes: 5%, 10%, 15%, 20%, 20%, 20% and 10%. Others: 30%, 40% and 30%.			
Plant IDC ($M)	4,236.6	131.7	658.7	Rate of 10% to align the cost to service year
Grid Integration EPC ($M)	6,656.4	53.3	471.0	
Owner's Cost for Grid Integration ($M)	665.6	5.3	47.1	10% of Integration cost
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		60%, 40%	
Grid Integration IDC ($M)	818.1	6.6	57.9	Rate of 10% to align the cost to service year
Financing Charges including Commitment ($M)	361.8	15.6	81.5	1.5% of sum of all EPC, Owner's cost and IDC
Commissioning Cost ($M)				For Kudu gas power plant only
Decommissioning Cost ($M)	482.4	20.7	108.7	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)	83,214	53,663	56,249	Based on the net capacity
Fixed O&M Cost ($/kW-Year)	559.2	600.0	600.0	Based on 1.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)	80.0	80.0	80.0	
CO2 Emission Rate (kg/GJ)				Not applicable
NOx Emission Rate (kg/GJ)				
SO2 Emission Rate (kg/GJ)				
Particulate Matter Emission Rate (kg/GJ)				

Note [1] : Namibia's 50% share only

Note: All Costs expressed in N$

Table 4-6: Wind Power Generation

Generation Technology		Wind	Comment
Fuel		Wind	
Plant Gross Capacity (MW)		50	
Plant Net Capacity (MW)		50	
Number of Units			
Economic Life (Year)		25	
Lead Time (Year)		3-5	
Earliest On-Line Year		2019	
Equivalent Availability (%)		95	
Equivalent Forced Outage Rate (%)		3.0	
Planed Outage Rate (%)		2.0	One week per year
Production Profile (Daily)		Non-dispatchable	
Production Profile (Seasonal)		Non-dispatchable	
Net Heat Rate (KJ/kWh, HHV)			
Primary Fuel Cost ($/GJ)			
Overall Capitalized Cost ($M)		2,046.0	
	Plant EPC ($M)	1,200.0	Based on net capacity
	Owner's Cost ($M)	60.0	5% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	60%, 40%	
	Plant IDC ($M)	140.8	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	471.0	
	Owner's Cost for Grid Integration ($M)	47.1	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	
	Grid Integration IDC ($M)	57.9	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	29.7	1.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)		For Kudu gas power plant only
	Decommissioning Cost ($M)	39.5	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		40,919	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		600.0	Based on 2.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		80.0	
CO2 Emission Rate (kg/GJ)			Not applicable
NOx Emission Rate (kg/GJ)			
SO2 Emission Rate (kg/GJ)			
Particulate Matter Emission Rate (kg/GJ)			

Note: All Costs expressed in N$

Table 4-7: Solar PV Power Generation

Generation Technology		Solar PV	Comment
Fuel		Sun Light	
Plant Gross Capacity (MW)		10	
Plant Net Capacity (MW)		10	
Number of Units			
Economic Life (Year)		25	
Lead Time (Year)		3-5	
Earliest On-Line Year		2019	
Equivalent Availability (%)		95	
Equivalent Forced Outage Rate (%)		3.0	
Planed Outage Rate (%)		2.0	One week per year
Production Profile (Daily)		Non-dispatchable	
Production Profile (Seasonal)		Non-dispatchable	
Net Heat Rate (KJ/kWh, HHV)			
Primary Fuel Cost ($/GJ)			
Overall Capitalized Cost ($M)		316.6	
	Plant EPC ($M)	208.0	Based on net capacity
	Owner's Cost ($M)	10.4	5% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	60%, 40%	
	Plant IDC ($M)	24.4	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	51.6	
	Owner's Cost for Grid Integration ($M)	5.2	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	
	Grid Integration IDC ($M)	6.3	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	4.6	1.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)		For Kudu gas power plant only
	Decommissioning Cost ($M)	6.1	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		31,661	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		520.0	Based on 2.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		80.0	
CO2 Emission Rate (kg/GJ)			Not applicable
NOx Emission Rate (kg/GJ)			
SO2 Emission Rate (kg/GJ)			
Particulate Matter Emission Rate (kg/GJ)			

Note: All Costs expressed in N$

Table 4-8: Concentrated Solar Power Generation

Generation Technology		CSP (No Storage)	CSP (4 Hour)	CSP (8-Hour)	CSP (12-Hour)	Comment
Fuel		Dsun Light				
Plant Gross Capacity (MW)		52	54	54	54	
Plant Net Capacity (MW)		50	50	50	50	
Number of Units		1	1	1	1	
Economic Life (Year)		25	25	25	25	
Lead Time (Year)		5-6	5-6	5-6	5-6	
Earliest On-Line Year		2021-2022	2021-2022	2021-2022	2021-2022	
Equivalent Availability (%)		90	90	90	90	Based on NERC database
Equivalent Forced Outage Rate (%)		5.0	5.0	5.0	5.0	
Planed Outage Rate (%)		4.0	4.0	4.0	4.0	Two weeks per year
Production Profile (Daily)		From no dispatchability to fully dispatchable				
Production Profile (Seasonal)		From no dispatchability to fully dispatchable				
Net Heat Rate (KJ/kWh, HHV)						
Primary Fuel Cost ($/GJ)						
Overall Capitalized Cost ($M)		2,480.7	3,214.7	4,525.4	5,836.1	
	Plant EPC ($M)	1,440.0	2,000.0	3,000.0	4,000.0	Based on net capacity
	Owner's Cost ($M)	144.0	200.0	300.0	400.0	10% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%				
	Plant IDC ($M)	248.4	345.0	517.6	690.1	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	471.0	471.0	471.0	471.0	
	Owner's Cost for Grid Integration ($M)	47.1	47.1	47.1	47.1	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%				
	Grid Integration IDC ($M)	57.9	57.9	57.9	57.9	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	24.1	31.2	43.9	56.7	1% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)					For Kudu gas power plant only
	Decommissioning Cost ($M)	48.2	62.4	87.9	113.3	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		49,613	64,293	90,507	116,721	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		864.0	1,200.0	1,800.0	2,400.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		160.0	160.0	160.0	160.0	
CO2 Emission Rate (kg/GJ)						Not applicable
NOx Emission Rate (kg/GJ)						
SO2 Emission Rate (kg/GJ)						
Particulate Matter Emission Rate (kg/GJ)						

Note: All Costs expressed in N$

Table 4-9: Biomass Power Generation

Generation Technology	BFB	BFB	Comment
Fuel	Invader Bush		
Plant Gross Capacity (MW)	5.6	11.2	
Plant Net Capacity (MW)	5	10	
Number of Units	1	1	
Economic Life (Year)	25	25	
Lead Time (Year)	5	5	
Earliest On-Line Year	2021	2021	
Equivalent Availability (%)	85	85	Based on NERC database
Equivalent Forced Outage Rate (%)	7.0	7.0	
Planed Outage Rate (%)	8.0	8.0	Four weeks per year
Production Profile (Daily)	Dispatched as per system requirements		
Production Profile (Seasonal)	Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)	15,000	14,500	
Primary Fuel Cost ($/GJ)	53.13	53.13	
Overall Capitalized Cost ($M)	314.3	589.0	
Plant EPC ($M)	200.0	368.0	Based on net capacity
Owner's Cost ($M)	10.0	18.4	5% of Plant's EPC cost
Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		
Plant IDC ($M)	32.9	60.6	Rate of 10% to align the cost to service year
Grid Integration EPC ($M)	53.3	106.7	
Owner's Cost for Grid Integration ($M)	5.3	10.7	10% of Integration cost
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	
Grid Integration IDC ($M)	6.6	13.1	Rate of 10% to align the cost to service year
Financing Charges including Commitment ($M)	3.1	5.8	1% of sum of all EPC, Owner's cost and IDC
Commissioning Cost ($M)			For Kudu gas power plant only
Decommissioning Cost ($M)	3.1	5.8	1% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)	62,863	58,899	Based on the net capacity
Fixed O&M Cost ($/kW-Year)	1,000.0	920.0	Based on 2.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)	320.0	240.0	
CO2 Emission Rate (kg/GJ)			Not applicable
NOx Emission Rate (kg/GJ)			
SO2 Emission Rate (kg/GJ)			
Particulate Matter Emission Rate (kg/GJ)			

Note: All Costs expressed in N$

Table 4-10: Small Modular Reactor Power Generation

Generation Technology		Nuclear	Nuclear	Comment
Fuel		Uranium		
Plant Gross Capacity (MW)		56	112	
Plant Net Capacity (MW)		50	100	
Number of Units		1	1	
Economic Life (Year)		40	40	
Lead Time (Year)		6-8	6-8	
Earliest On-Line Year		Per technology development		
Equivalent Availability (%)		88	88	Based on NERC database
Equivalent Forced Outage Rate (%)		3.0	3.0	
Planed Outage Rate (%)		8.0	8.0	Four weeks per year
Production Profile (Daily)		Dispatched as per system requirements		
Production Profile (Seasonal)		Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)		11,000	11,000	
Primary Fuel Cost ($/GJ)		16	16	
Overall Capitalized Cost ($M)		9,320.7	17,605.8	
	Plant EPC ($M)	7,200.0	13,600.0	Based on net capacity
	Owner's Cost ($M)	360.0	680.0	5% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	15%, 35%, 35%, 15%		
	Plant IDC ($M)	1,623.0	3,065.6	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M) [1]			
	Owner's Cost for Grid Integration ($M)			
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	
	Grid Integration IDC ($M)			
	Financing Charges including Commitment ($M)	45.9	86.7	0.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)			For Kudu gas power plant only
	Decommissioning Cost ($M)	91.8	173.5	1% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		186,414	176,058	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		2,160.0	2,040.0	Based on 1.5% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		240.0	240.0	
CO2 Emission Rate (kg/GJ)				Not applicable
NOx Emission Rate (kg/GJ)				
SO2 Emission Rate (kg/GJ)				
Particulate Matter Emission Rate (kg/GJ)				

Note: [1] Grid connection has not been costed because of complexity and extremely large project scope

Note: All Costs expressed in N$

Table 4-11: Power Generation Using Municipal Solid Waste

Generation Technology		WTE	WTE	Comment
Fuel		MSW		
Plant Gross Capacity (MW)		10.6	21.2	
Plant Net Capacity (MW)		10	20	
Number of Units		1	1	
Economic Life (Year)		25	25	
Lead Time (Year)		5-7	5-7	
Earliest On-Line Year		2021/2023		
Equivalent Availability (%)		80	80	Based on NERC database
Equivalent Forced Outage Rate (%)		10.0	10.0	
Planed Outage Rate (%)		8.0	8.0	Four weeks per year
Production Profile (Daily)		Dispatched as per system requirements		
Production Profile (Seasonal)		Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)		18,000	17,500	
Primary Fuel Cost ($/GJ)		108	108	
Overall Capitalized Cost ($M)		1,609.1	3,021.0	
	Plant EPC ($M)	1,280.0	2,400.0	Based on net capacity
	Owner's Cost ($M)	64.0	120.0	5% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		
	Plant IDC ($M)	210.8	395.2	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	25.0	50.0	
	Owner's Cost for Grid Integration ($M)	2.5	5.0	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		
	Grid Integration IDC ($M)	3.1	6.1	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	7.9	14.9	0.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)			For Kudu gas power plant only
	Decommissioning Cost ($M)	15.9	29.8	1% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		160,914	151,051	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		2,560.0	2,400.0	Based on 2% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		320.0	320.0	
CO2 Emission Rate (kg/GJ)				Not applicable
NOx Emission Rate (kg/GJ)				
SO2 Emission Rate (kg/GJ)				
Particulate Matter Emission Rate (kg/GJ)				

Note: All Costs expressed in N$

Table 4-12: Bio-Fuel Power Generation

Generation Technology		CCGT	CCGT	Comment
Fuel		Bio-fuel		
Plant Gross Capacity (MW)		78	156	
Plant Net Capacity (MW)		75	150	
Number of Units		1	1	
Economic Life (Year)		25	25	
Lead Time (Year)		6-7	6-7	
Earliest On-Line Year		2022-2023	2022-2023	
Equivalent Availability (%)		88	88	Based on NERC database
Equivalent Forced Outage Rate (%)		6.0	6.0	
Planed Outage Rate (%)		6.0	6.0	Three weeks per year
Production Profile (Daily)		Dispatched as per system requirements		
Production Profile (Seasonal)		Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)		7,800	7,216	
Primary Fuel Cost ($/GJ)		379.52	379.52	
Overall Capitalized Cost ($M)		1,886.9	3,615.8	
	Plant EPC ($M)	1,080.0	2,040.0	Based on net capacity
	Owner's Cost ($M)	108.0	204.0	10% of Plant's EPC cost
	Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		
	Plant IDC ($M)	186.3	351.9	Rate of 10% to align the cost to service year
	Grid Integration EPC ($M)	367.0	734.0	
	Owner's Cost for Grid Integration ($M)	36.7	73.4	10% of Integration cost
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		
	Grid Integration IDC ($M)	45.1	90.2	Rate of 10% to align the cost to service year
	Financing Charges including Commitment ($M)	27.3	52.4	1.5% of sum of all EPC, Owner's cost and IDC
	Commissioning Cost ($M)			For Kudu gas power plant only
	Decommissioning Cost ($M)	36.5	69.9	2% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)		25,159	24,106	Based on the net capacity
Fixed O&M Cost ($/kW-Year)		432.0	408.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)		240.0	240.0	
CO2 Emission Rate (kg/GJ)				Not applicable
NOx Emission Rate (kg/GJ)				
SO2 Emission Rate (kg/GJ)				
Particulate Matter Emission Rate (kg/GJ)				

Note: All Costs expressed in N$

Table 4-13: Geothermal Power Generation

Generation Technology	Geothermal	Geothermal	Comment
Fuel	Geothermal		
Plant Gross Capacity (MW)	5.6	22.4	
Plant Net Capacity (MW)	5	20	
Number of Units	1	1	
Economic Life (Year)	25	25	
Lead Time (Year)	8-10	8-10	
Earliest On-Line Year	2024-2026	2024-2026	
Equivalent Availability (%)	86	86	Based on NERC database
Equivalent Forced Outage Rate (%)	8.0	8.0	
Planed Outage Rate (%)	6.0	6.0	Three weeks per year
Production Profile (Daily)	Dispatched as per system requirements		
Production Profile (Seasonal)	Dispatched as per system requirements		
Net Heat Rate (KJ/kWh, HHV)	11,500	11,000	
Primary Fuel Cost ($/GJ)	128	128	
Overall Capitalized Cost ($M)	659.9	2,441.2	
Plant EPC ($M)	520.0	1,920.0	Based on net capacity
Owner's Cost ($M)	26.0	96.0	5% of Plant's EPC cost
Plant CAPEX Disbursement Flow (%)	30%, 40%, 30%		
Plant IDC ($M)	85.6	316.2	Rate of 10% to align the cost to service year
Grid Integration EPC ($M)	12.5	50.0	
Owner's Cost for Grid Integration ($M)	1.3	5.0	10% of Integration cost
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%		
Grid Integration IDC ($M)	1.5	6.1	Rate of 10% to align the cost to service year
Financing Charges including Commitment ($M)	6.5	23.9	1% of sum of all EPC, Owner's cost and IDC
Commissioning Cost ($M)			For Kudu gas power plant only
Decommissioning Cost ($M)	6.5	23.9	1% of sum of all EPC, Owner's cost and IDC
Overall Plant Capital Unit Capacity Cost ($/kW)	131,971	122,060	Based on the net capacity
Fixed O&M Cost ($/kW-Year)	3,120.0	2,880.0	Based on 3% of EPC cost, including insurance
Variable O&M Cost ($/MWh)	240.0	240.0	
CO2 Emission Rate (kg/GJ)			Not applicable
NOx Emission Rate (kg/GJ)			
SO2 Emission Rate (kg/GJ)			
Particulate Matter Emission Rate (kg/GJ)			

Note: All Costs expressed in N$

5. Load Forecast and Supply/Demand Balance

5.1 Historic Sales and Load Data

The power sector in Namibia is dominated by NamPower, which is responsible for most generation, transmission and a small portion of the distribution business. The majority of the distribution sector is serviced by individual distributors including three REDs as well as a number of local and regional authorities.

The longest data series for electricity consumption in Namibia is based on the figures published in the NamPower Annual Reports. These data do not, however, isolate sales by location or type of consumer, although they do identify exports and ESKOM direct supplies to Orange River and the Skorpion Mine. All data are on a fiscal year basis – July to June. This data is summarised in Table 5-1.

Table 5-1: Namibia Overall Electricity Data (GWh) (1988/89 to 2014/15)

Fiscal Year	Units Sent Out	Total Units Sold	Units Exported	Units to Orange River	Units to Skorpion	Units Sold in Namibia	Apparent Transmission Losses
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	
1989	1835	1659	267			1392	9.59%
1990	1790	1612	166			1446	9.94%
1991	1919	1719	201			1518	10.42%
1992	1948	1714	204			1510	12.01%
1993	1746	1551	49			1502	11.17%
1994	1753	1553	28			1525	11.41%
1995	2015	1784	146			1638	11.46%
1996	1951	1731	30			1701	11.28%
1997	1949	1700	1			1699	12.78%
1998	2211	1904	21			1883	13.89%
1999	2085	1863	56			1807	10.65%
2000	2192	1978	100			1878	9.76%
2001	2277	2050	69			1981	9.97%
2002	2371	2136	54			2082	9.91%
2003	2466	2246	53		76	2117	9.21%
2004	2945	2795	23	257	471	2044	6.77%
2005	3363	2976	31	206	596	2143	15.11%
2006	3554	3199	36	184	682	2297	13.21%
2007	3621	3259	40	191	629	2399	12.92%
2008	3719	3392	47	224	663	2458	11.55%
2009	3692	3358	68	122	639	2529	11.40%
2010	3767	3431	77	130	673	2551	11.34%
2011	3910	3543	76	127	690	2650	11.87%
2012	4162	3726	91	133	662	2840	12.95%
2013	4238	3861	89	139	647	2986	10.92%
2014	4384	3827	84	145	571	3027	15.19%
2015	4254	3870	88	139	474	3169	10.55%

The Total Units Sold as listed in Table 5-1 are NamPower sales to either distributors or to direct customers such as mines, water pumping schemes and NamPower's distribution customers. Data on delivery through the distributors' systems and sales to the ultimate customers are not recorded by NamPower.

The number of customers and sales volume are recorded for each distributor by four consumption categories: domestic, commercial, Bulk/Large Power User (LPU) and

Institutional (Inst). The number of customers for the fiscal year 2014/15 is listed in Table 5-2. Approximately ninety percent of the distribution customers are in the domestic category.

Table 5-2: Number of Customers for 2014/15

Distribution Area	Domestic	Commercial	Bulk/LPU	Inst	Total
NORED	56,000	2,309	529	-	58,838
OPE	5,045	440	54	34	5,573
CENORED	22,019	2,276	71	664	25,030
ERONGO RED	33,404	3,193	249	165	37,011
Central Namibia	65,621	5,902	1,034	-	72,557
Southern Namibia	26,943	1,680	281	11	28,916
NamPower DX	14	2,549	111	-	2,674
Distribution Total	**209,046**	**18,349**	**2,329**	**874**	**230,599**

Source: ECB

The sales statistics for the fiscal year 2014/15 are displayed in Table 5-3. This table includes the distribution portion of the NamPower operations.

Table 5-3: Sales Statistics for 2014/15 (MWh)

Distribution Area	Domestic	Commercial	Bulk/LPU	Inst	Total
NORED	175,164	36,524	106,778	0	318,466
OPE	18,378	6,569	26,030	6,869	57,846
CENORED	58,797	50,277	24,835	38,160	172,069
ERONGO RED	163,251	58,215	173,835	3,162	398,463
Central Namibia	393,129	129,045	376,207	0	898,381
Southern Namibia	70,057	28,379	57,967	4	156,406
NamPower DX	262	74,715	121,903	0	196,880
Distribution Total	**879,037**	**383,724**	**887,555**	**48,195**	**2,198,511**

Source: ECB

For the sales in 2014/15, some 40 percent are in the domestic tariff category, 17 percent are in the commercial category, 40 percent are bulk sales and the remaining 3 percent are institutional. Slightly more than 40 percent of the total distribution sales were recorded for the Central area which includes the City of Windhoek and surrounding towns.

The NamPower Annual Report for the period ending 30 June 2015 reports total sales in Namibia of 3,169 GWh. The main difference between this number and the 2,198 GWh shown in Table 5-3 is the NamPower sales to its transmission connected customers. Table 5-4 links the 2014/15 ECB sales data with the NamPower Annual Report figures. The table shows the ECB sales reported by the distributors plus NamPower direct transmission level sales totalling 2,891 GWh. The annual report sales value is 3,169 GWh which implies average distribution losses of 8.7%.

The reported peak demand in the Annual Report for the Namibian plus export system is 597 MW (2014/2015). When the Skorpion Mine and Orange River Supply are included the overall system peak is 657 MW.

Table 5-4: Comparison of Electricity Sales – 2014/15

	Domestic Sales (MWh)	Commercial Sales (MWh)	Bulk Sales (MWh)	Inst Sales (MWh)	Total Sales (MWh)	Annual Report Sales (MWh)	Annual Report Demand (MW)
ECB Data							
NORED	175,164	36,524	106,778	0	318,466		
OPE	18,378	6,569	26,030	6,869	57,846		
CENORED	58,797	50,277	24,835	38,160	172,069		
ERONGO RED	163,251	58,215	173,835	3,162	398,463		
Central Namibia	393,129	129,045	376,207	0	898,381		
Southern Namibia	70,057	28,379	57,967	4	156,406		
NamPower DX	262	74,715	121,903	0	196,880		
Distribution Total	**879,037**	**383,724**	**887,555**	**48,195**	**2,198,511**		
NamPower TX End Cons					692,773		
Total Sales					**2,891,284**		
Annual Report Data							
Total Sales in Namibia						3,169,000	
Export Sales						88,000	
Subtotal						3,257,000	597
Orange River						139,000	
Skorpion Mine						474,000	
Total Units Sold						3,870,000	657

Source: ECB and NamPower

5.2 Review of NIRP Load Forecast

5.2.1 General Approach and NIRP 2013 Forecast

The load forecast used in NIRP 2013 was prepared in March 2012. This forecast is summarised in Table 5-5.

The overall growth rate in the reference scenario is 4.25 percent over the entire forecast period to 2031. This compares to the historical long term energy sales growth rate of 3.6 percent.

The forecast is segregated into the organic load growth – the load that is existing on the system and further development of that load over time - and the step loads, new loads that are considered too large to be included in the allowances for organic growth. The average annual growth in the organic load is 2.85 percent; the remaining growth is associated with new step loads.

Table 5-5: Reference Forecast Summary NIRP 2013 (GWh)

Year	Sales Organic (GWh)	Sales Step (GWh)	Sales Total (GWh)	Generation Total (GWh)	Generation Peak (MW)
2008	2,512	0	2,512	2,763	443.7
2009	2,577	0	2,577	2,802	470.1
2010	2,756	0	2,756	2,976	477.0
2011	2,889	0	2,889	3,231	511.7
2012	2,956	9	2,965	3,316	525.7
2013	3,037	183	3,220	3,601	562.8
2014	3,123	464	3,586	4,011	614.0
2015	3,202	1,116	4,318	4,829	710.6
2016	3,285	1,505	4,790	5,357	774.9
..					
2021	3,824	1,696	5,520	6,173	901.3
..					
2026	4,410	1,499	5,909	6,608	988.5
..					
2031	5,071	1,576	6,646	7,432	1124.4
2011-2031	2.85%		4.25%	4.25%	4.02%

Figure 5-1 displays the reference energy forecast for both sales and generation.

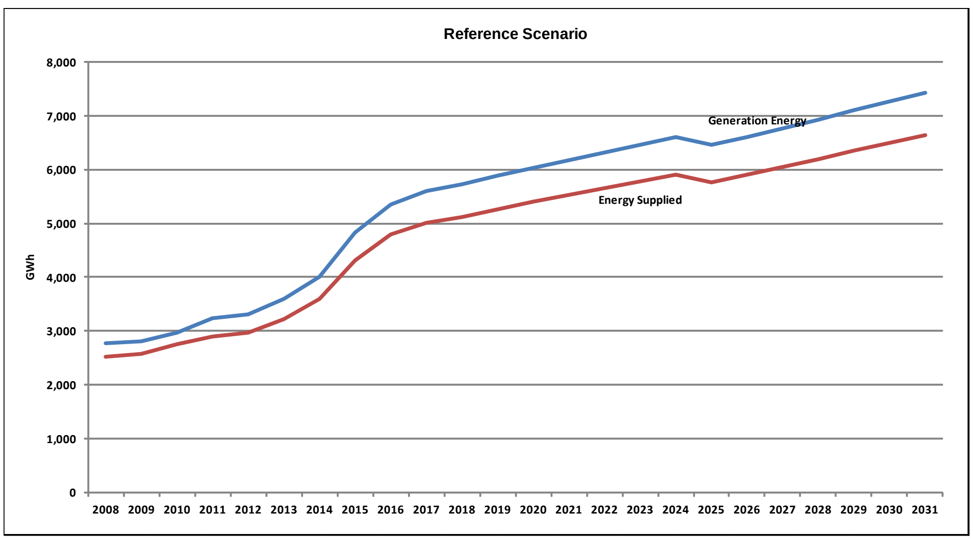

Figure 5-1: Reference Sales and Generation (GWh)

Low and high forecasts were also prepared. Table 5-6 summarises the three forecasts in numerical form and Figure 5-2 displays the forecasts in graphical form (the low forecast is the green line, the reference forecast is the blue line and the high forecast is the red line).

Table 5-6: Generation Forecast Summary

Year	Low Energy (GWh)	Low Peak (MW)	Reference Energy (GWh)	Reference Peak (MW)	High Energy (GWh)	High Peak (MW)
2008	2,763	443.7	2,763	443.7	2,763	443.7

2009	2,802	470.1	2,802	470.1	2,802	470.1
2010	2,976	477.0	2,976	477.0	2,976	477.0
2011	3,231	511.7	3,231	511.7	3,231	511.7
2012	3,245	513.8	3,316	525.7	3,349	531.3
2013	3,482	542.8	3,601	562.8	3,668	573.8
2014	3,842	585.9	4,011	614.0	4,183	639.0
2015	4,381	648.1	4,829	710.6	5,667	812.0
2016	4,746	690.9	5,357	774.9	6,650	936.9
..						
2021	5,197	758.9	6,173	901.3	8,358	1178.8
..						
2026	5,424	811.5	6,608	988.5	8,911	1272.0
..						
2031	6,028	910.4	7,432	1124.4	9,865	1429.1
2011-2031	3.17%	2.92%	4.25%	4.02%	5.74%	5.27%

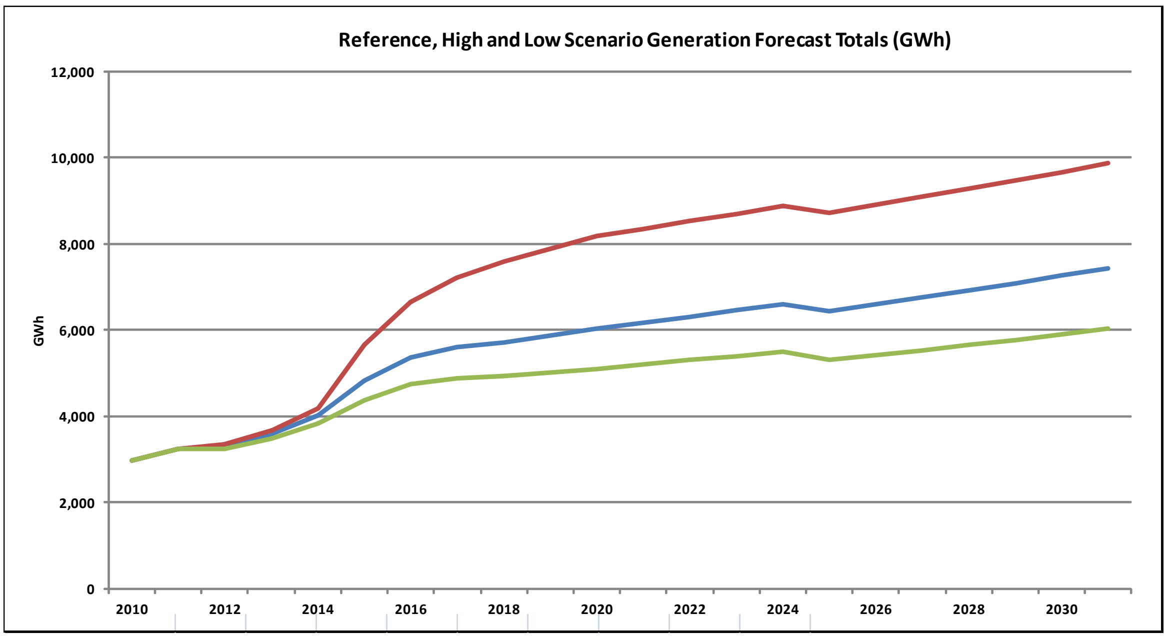

Figure 5-2: Overall Generation Forecasts – Energy (GWh)

5.3 The Namibian Economy

5.3.1 Background

On the basis of the most recent figures, the Namibian economy achieved an annual growth rate of approximately 6.4 percent in 2014 when expressed at constant prices. This is above the long-run average annual growth rate of 4.4 percent observed over the period from 1990 to 2014. The total GDP for financial year 2014 at current prices is N$ 141,033 million (see Figure 5-3) or approximately US$5,820 per capita.

The Namibian economy is dominated by the services sector – the tertiary industries which include wholesale and retail trade, transport and storage, finance and insurance and public administration. This sector represents approximately 60 percent of total GDP for 2014. The average annual growth rate of this sector over the past 20 years expressed at constant prices is 4.8 percent.

The second largest sector of the economy is the secondary industries including manufacturing, construction, electricity and water. This sector represents approximately 18 percent of total GDP and has been growing at an average annual rate of 4.3 percent from 1990 to 2014.

The final general GDP category is the primary industries which include agriculture, forestry, fishing and mining. This sector represents approximately 16 percent of total GDP and as it has been growing at a lower rate than the other sectors its share of total GDP has actually been declining. Growth from 1990 has averaged 2.6 percent per year.

The largest component of the primary industrial sector is mining and quarrying representing 9.5 percent of the total GDP in 2014. The impact of this sector on the economy is much larger than the direct value-added figure would suggest. Mining has a large impact on both the secondary and the tertiary industries. In 2014, mining activities directly consumed 639 GWh or approximately 20 percent of total sales.

Mining is dominated by the diamond industry. While not a significant consumer of electricity, diamond mining represents two-thirds of mining sector value-added. Diamond production in 2009 was at one of its lowest levels in twenty years. While diamond production increased somewhat from 2010 to 2014, exports into 2015 have displayed a slight decline. The high inventory levels of global polished diamonds, which stemmed from weak demand, resulted in lower exported volumes of rough diamonds. The remainder of the mining sector includes gold, zinc, copper and uranium.

Namibia is the fifth largest producer of uranium in the world. Annual production is approximately 6 percent of world supply. The Rössing mine is the third largest uranium mine in the world. The current power consumption in the uranium mining sector represents nearly ten percent of the total peak power demand in Namibia. The effects of the incident at the Fukushima Daiichi nuclear plant in Japan are clear in the production values as international demand dropped.

While uranium prices in 2015 recovered somewhat from the lows of 2014, the weak export earnings into 2015 were primarily due to a decline in volumes of exports.

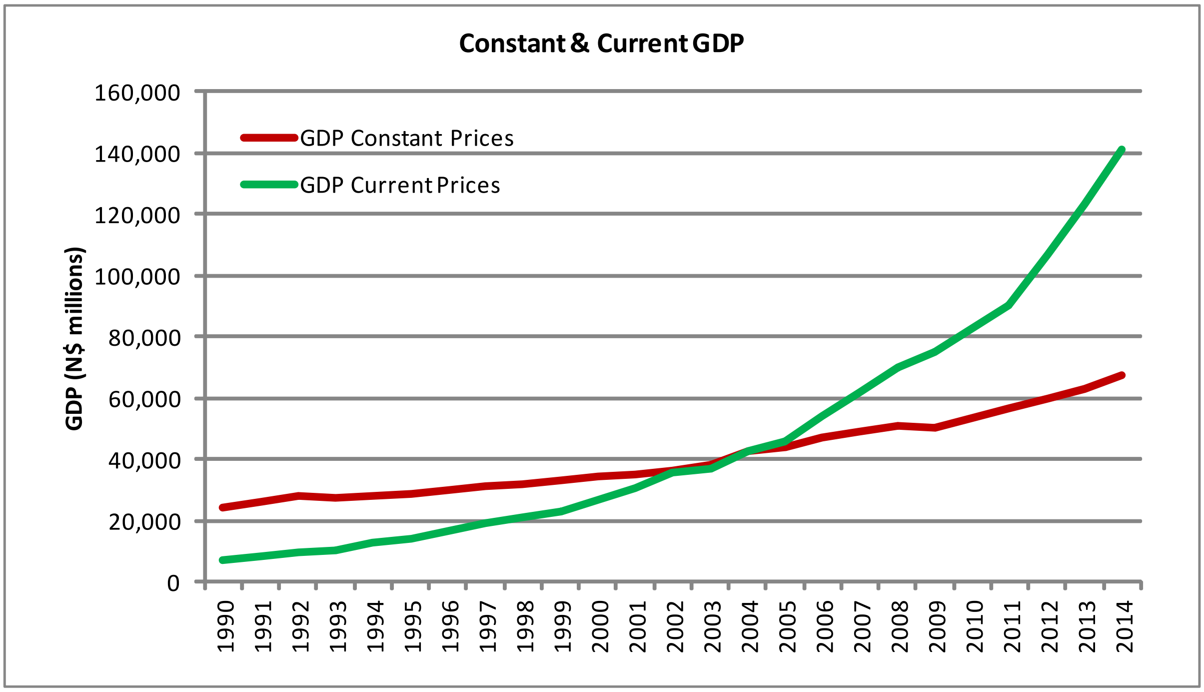

Figure 5-3: Constant and Current Total GDP

The Namibian rate of inflation is measured by the National Planning Commission's Consumer Price Index. The long-term growth rate (1990 to 2015) for the CPI index is 7.65 percent. Recent years have displayed continued low levels of inflation. The 2013 value was 5.6 percent, the 2014 rate was 5.4 percent and the rate for 2015 is 3.4 percent.

The value of the Namibian Dollar is tied to that of the South African Rand. The average exchange rate for 2011 was 7.21 Rand per US$ and it has displayed a continual rise since that year. The average exchange rate for 2015 was 12.41 Rand per US$ and the value has depreciated significantly in recent months to the 16 Rand to the US$ level.

Details on a number of the economic statistics discussed above are provided in Table 5-7.

Table 5-7: Selected Economic Statistics (1990 - 2014)

Year	Gross Domestic Product: Current Total GDP	(at 2004 Prices) Agric. Fishing	Mining	Secondary Industries	Tertiary Industries	Total GDP	Average Exch. Rate	CPI Index	CPI Annual Change
	(millions of N$)						(Rand/$US)	(2012=100)	
1990	7,256	2,186	1,921	4,907	13,585	23,998	2.5877	18.02	
1991	8,319	2,480	2,276	4,669	14,729	25,957	2.7609	21.48	19.20%
1992	9,835	2,333	2,451	5,417	15,646	27,823	2.8516	23.57	9.73%
1993	10,517	2,530	1,895	5,300	16,304	27,384	3.2667	25.99	10.27%
1994	12,913	2,871	2,096	5,737	15,609	27,858	3.5497	29.06	11.81%
1995	14,300	2,819	2,223	5,760	16,367	28,944	3.6270	31.15	7.19%
1996	16,962	3,037	2,311	5,199	17,194	29,867	4.2964	34.25	9.95%
1997	18,905	2,851	2,406	5,607	17,916	31,128	4.6073	36.19	5.66%
1998	21,154	3,078	2,345	6,143	18,301	32,152	5.5316	39.39	8.84%
1999	23,332	3,238	2,542	5,944	18,974	33,236	6.1131	42.31	7.41%
2000	27,125	3,530	2,499	6,126	19,719	34,396	6.9484	46.79	10.59%
2001	30,535	3,290	2,290	6,571	20,351	34,802	8.6179	50.85	8.68%
2002	35,430	3,624	3,115	6,350	20,595	36,468	10.5135	57.37	12.82%
2003	37,304	3,774	2,860	7,235	22,022	38,014	7.5554	59.73	4.11%
2004	42,678	3,816	4,147	7,377	24,304	42,679	6.4426	61.25	2.54%
2005	46,177	4,024	3,697	8,026	24,822	43,758	6.3627	63.47	3.62%
2006	54,028	3,995	4,718	8,680	26,194	46,853	6.7676	67.27	5.99%
2007	61,583	3,623	4,742	9,456	28,205	49,430	7.0467	72.53	7.82%
2008	70,111	3,104	4,606	9,766	29,708	51,038	8.2530	80.92	11.57%
2009	75,214	3,161	2,694	9,786	31,136	50,482	8.4083	86.03	6.31%
2010	82,599	3,117	3,533	10,416	32,587	53,649	7.3107	89.00	3.45%
2011	90,108	3,525	3,253	10,902	34,188	56,694	7.2124	95.10	6.85%
2012	106,865	4,000	3,643	11,328	36,362	59,538	8.1569	100.00	5.15%
2013	123,150	3,597	4,017	12,307	38,984	63,327	9.4739	104.90	4.90%
2014	141,033	3,747	3,796	13,464	41,869	67,752	10.8374	109.80	4.67%
Growth	13.2%	2.27%	2.88%	4.30%	4.80%	4.42%		7.65%	

Namibia's long-term economic growth potential is high as the country begins to make fuller use of its resources and expands from a comparatively small market base. An important factor will be developments in the mining sector, particularly the mining of diamonds and uranium. New uranium developments as well as the expansion of existing mines are contingent upon a recovery of the demand for and the price of uranium. While mining accounts for approximately 10 percent of GDP it represents a large portion of export earnings.

5.3.2 Projections

Economic Activity

Statistics of economic activity are reported by the National Planning Commission (NPC). The average annual GDP growth rate for the most recent 25 years was approximately 4.4

percent. The GDP growth rate for the last three years (2011 to 2014) grew from 5.1 percent to 5.7 percent in 2013 and finally to 6.4 percent in 2014.

The Bank of Namibia produces a forecast based on the most recent GDP values. In its Economic Outlook Update published in December 2015 it forecast 4.5% growth in GDP for 2014/15, 4.3% for 2015/16 and 5.9% for 2016/17.

The Ministry of Finance through the Macro-Economic Working Group has prepared national economic forecasts published as part of the Fiscal Strategy in September 2014. The forecasts were developed within three development scenarios: Pessimistic, Most Likely and Optimistic. The projected GDP growth rates are displayed in Table 5-8.

Table 5-8: GDP Projections

	Ministry of Finance Macroeconomic Framework Sept 2014				Bank of Namibia Economic Outlook Update Dec 2015	
		Pessimistic	**Most Likely**	**Optimistic**		**Baseline**
2012/13	Act	5.1%	5.1%	5.1%	Act	5.1%
2013/14	Est.	5.7%	6.2%	6.7%	Act.	6.4%
2014/15	Proj.	5.1%	5.7%	6.1%	Proj.	4.5%
2015/16	Proj.	4.9%	5.4%	5.9%	Proj.	4.3%
2016/17	Proj.	4.5%	5.0%	5.5%	Proj.	5.9%
2017/18	Proj.	3.9%	4.4%	4.9%	Proj.	---

The development scenarios are built upon very similar assumptions. In the most general terms, the Most Likely and Baseline scenarios assume that the global economic recovery gradually proceeds, commodity prices (typically uranium and copper) stabilise and then grow as well as modest depreciation in the Namibian currency encouraging exports and tourism.

The Pessimistic scenario assumes a stalled recovery in the global economy, continued low commodity prices and an appreciation in the Namibia currency. The Optimistic scenario assumes faster than expected global economic growth, increasing commodity prices and some depreciation in the Namibian currency.

Electricity Prices

The ECB approved increase in the NamPower electricity tariff rates in 2011 brought NamPower to the objective of pricing to meet Long Run Marginal Cost (LRMC). It is the expectation that ECB will endeavour to maintain the relationship between the tariff and LRMC. NamPower has expressed the opinion that several years of higher than average electricity price increases will be required to maintain a cost reflective tariff.

Eskom which has been the source of approximately 30 percent of the energy sold in Namibia (excluding Skorpion Mine) applied to the National Energy Regulator of South Africa for annual tariff increases in the order of 16 to 30 percent in each of the years 2008/09 to 2012/13. Tariff increases in the last two have been 8 percent per year. The proposed increase for 2015/16 is 12.7 percent. It is also expected that generation expansion in Namibia, particularly in the near-term, will involve relatively more expensive generation options.

Table 5-9 displays proposed price increases for the load forecasting. The low demand scenario incorporates the highest expected tariff increase. A negative price elasticity of demand would mean that large price increases will result in lower growth. Similarly, the high demand scenario incorporates a lower expected rate of tariff increase.

Table 5-9: Tariff Scenarios

(Percentage Increase per Year)

	Low Load	Reference	High Load
2012-17	20%	15%	10%
2018	15%	10%	5%
2019 &	10%	5%	5%

Source: Hatch

Population Growth

On the basis of the 2011 Census, the Namibia Statistics Agency published a population projection to 2041 at the National and the Regional levels. Three variants of the projection were produced.

The principal inputs to the projection are assumptions as to the fertility, mortality and migration patterns within the population. Fertility is the main component in population change. There are various factors which influence the level of fertility. These include, among others, age of entry into child bearing, family planning, marital status, level of education and employment status. The factors are generally based on data from the 2011 Population and Housing Census. Fertility rates were developed for the initial and final years of the projection as well as a number of intermediate years. Rates were prepared at a national level, for each individual region and for each variant.

The main indicator of mortality is the life expectancy at birth, defined as the average number of years a new-born will be expected to live if it is exposed to the mortality pattern for the year under consideration. The process of coming up with assumptions on the future trend of life expectancy at birth involved the examination of the past trend as well as the 2011 census results relating to mortality. As with the fertility rates, mortality rates were developed for the initial, a number of intermediate and the final year of the projection both at the national and region levels for each variant.

There are no statistics on international migration. It was therefore assumed that, at the national level migration is not significant. This implies that in and out migrants will cancel each other out. However, there was significant internal migration between the regions observed in the 2011 census. The principal migration pattern is from the northern regions to the urban areas in the regions of Khomas, Erongo and Karas.

Table 5-10 summarises the national population projections for all three variants. For the medium variant the expected average annual rate of population growth for Namibia is 1.7% over the 30-year forecast period. This indicates a population doubling rate of 41.2 years.

The average annual rates of population growth for the low and high variants are 1.41 percent and 1.97 percent, respectively. Over the 30-year period, the difference between the high and the low projections is approximately half a million people.

Table 5-10: Population Projection, National

Year	Low Variant	Medium Variant	High Variant
2011	2,116,077	2,116,077	2,116,077
2012	2,155,326	2,155,440	2,155,555
2013	2,195,628	2,196,086	2,196,547
2014	2,236,853	2,237,894	2,238,938
2015	2,278,843	2,280,716	2,282,591
2016	2,321,427	2,324,388	2,327,350
2017	2,364,431	2,368,747	2,373,062
2018	2,407,697	2,413,643	2,419,587
2019	2,451,079	2,458,936	2,466,792
2020	2,494,439	2,504,498	2,514,555
2021	2,537,669	2,550,226	2,562,779
2022	2,580,679	2,596,037	2,611,390
2023	2,623,388	2,641,857	2,660,322
2024	2,665,736	2,687,636	2,709,531
2025	2,707,680	2,733,338	2,758,993
2026	2,749,194	2,778,948	2,808,699
2027	2,790,265	2,824,465	2,858,661
2028	2,830,885	2,869,897	2,908,907
2029	2,871,045	2,915,254	2,959,467
2030	2,910,729	2,960,542	3,010,364
2031	2,949,906	3,005,745	3,061,606
2032	2,988,530	3,050,838	3,113,184
2033	3,026,540	3,095,780	3,165,085
2034	3,063,861	3,140,519	3,217,282
2035	3,100,421	3,185,005	3,269,750
2036	3,136,159	3,229,197	3,322,477
2037	3,171,009	3,273,051	3,375,444
2038	3,204,884	3,316,498	3,428,606
2039	3,237,696	3,359,466	3,481,915
2040	3,269,359	3,401,887	3,535,327
2041	3,299,805	3,443,709	3,588,815

Source: NPC

5.4 Background to the Load Forecast

5.4.1 The Demand for Electricity

The demand for electricity is a derived demand. Electricity is consumed as a means to an end such as cooking or lighting and cannot be used without equipment designed for that specific purpose. The demand for electricity is therefore related to the stock of capital equipment as well as the demand for the output of this equipment. The principal factors affecting the amount of electricity demanded are:

- **The Stock of Electricity Consuming Equipment.** This includes the housing stock, whether this is new or existing housing in an urban or a rural setting. Consumers in new housing have a choice for major equipment purchases while consumers in existing houses have a fixed stock of equipment which is unlikely to change significantly for many years. Another important consideration is the level of technological advancement of the stock of equipment and the rate of technological change. Two recent examples of such change are the increase in the number of small computers, smart phones, tablets and other electronic equipment and the development and introduction of energy efficient light bulbs.

- **Income/Economic Activity.** In the residential sector it is expected that the higher the household income, the larger is the demand for electricity in that household as a result of the larger stock of electrical consuming equipment. In the commercial and industrial sectors, higher economic activity indicates higher demand for goods and services.
- **Prices.** In general, the higher the price of electricity, relative to the prices of other forms of energy, the lower the relative demand for electricity. Similarly, the higher the price of electricity consuming equipment when compared to the price of the equipment required for other forms of energy, the lower the demand for this equipment and therefore the lower the demand for electricity.
- **Population.** The number and size of households has a big impact on the residential sector load and can also have a large impact on the commercial sector load.
- **Other Factors.** The main factors in this area are climate and weather. Climate affects the stock of equipment while weather affects its intensity of use. If the time periods under analysis are shorter, for example weekly or daily, more detailed demand factors would be required to describe system loading.

While some of the data associated with the demand for electricity is either not available or would require a detailed power market survey to obtain (for example, the stock and intensity of use of electrical equipment), much is recorded in sufficient quantity and detail to be used for regression studies. In many cases, however, proxies for the above data have been adopted; for example, Gross Domestic Product as a proxy for household income.

5.4.2 Adjustments to the Data Series

The data base used for the regression analysis covers the period from 1989 - 2014 inclusive. Electricity consumption data is based on the NamPower Annual Report values for ‘Units sold in Namibia’. This data includes sales by NamPower to its direct customers (Mines, Industries and Water Pumping) as well as to distributors such as NORED and CENORED. These data exclude sales associated with the Skorpion Mine in southern Namibia which is supplied directly from Eskom.

A number of other data sources were investigated. These data included estimates of sales by customer category; however, there was a lack of consistency between these data and the Annual Report figures.

One adjustment was, however, required of the Annual Report data. This adjustment converted the reported values from financial years to calendar years to match the available independent variables. The adjustment was based on a review of the detailed data in the original NIRP study.

$$19YY = 0.50 \times 19XX.YY + 0.50 \times 19YY.ZZ \quad (1)$$

5.4.3 Regression Analysis

Regression analysis was carried out to prepare the load forecast. This analysis was based on the logarithms of both the dependent and the independent variables. Regressions based on absolute values of the variables were tested, but the correlations were poor. The general equation considered in the analysis is:

$$Y = a * X^b * Z^c \quad (2)$$

This equation is linear in the parameters (*a*, *b*, and *c*) when expressed in double logarithmic form:

$$\text{Log}(Y) = \log(a) + b\,\text{Log}(X) + c\,\log(Z) \qquad (3)$$

One advantage of the double logarithmic form is that the parameters derived from the regressions represent the elasticity of demand relative to the independent variable. The parameters in this particular model are constant elasticities of demand.

Elasticity is an important concept. It is the measure of how much one variable changes in response to changes in another variable. Specifically, it is the ratio of the percentage change in the dependent variable to that of the independent variable, all other variables held constant.

There are three specific elasticities:

- **Income Elasticity** relates changes in the amount of electricity demanded to changes in consumers' income. In general, income elasticities are positive; i.e. an increase in income will increase electricity consumption.
- **Price Elasticity** relates changes in the amount of electricity demanded to changes in the price of electricity. Typically, price elasticities are expected to be negative; i.e. an increase in price will decrease electricity consumption.
- **Cross-price Elasticity** relates changes in the amount of electricity demanded to changes in the price of related goods. There are two general classes of related goods; namely, substitutes to electricity consumption and complements to electricity consumption. Typically, if the cross price elasticity of the related good is negative, i.e. an increase in price decreases electricity consumption, the good is said to be a complement, whereas if the elasticity is positive, it is said to be a substitute.
- **Elasticities** are also classified by their absolute value. An elasticity value which is greater than 1 (absolute value) is said to be elastic, that is, a change in the independent variable is related to a more than proportional change in the dependent variable. If the elasticity value is exactly 1, the elasticity is unitary and if the absolute value of the elasticity is less than one, the relationship between the variables is inelastic. An inelastic relationship indicates that a change in the independent variable is related to a less than proportional change in the dependent variable.

5.4.4 Regression Results

A variety of relationships between electricity sales and the available exogenous variable were tested in the preparation of this forecast update. Specifically, the following tests were undertaken:

- Sales data from NamPower’s Annual Reports was converted to a calendar basis and tested against GDP expressed at constant prices.
- An alternative NamPower sales database which identified sales by broad consumption categories was converted to a calendar basis and tested against GDP expressed at constant prices.

- The alternative NamPower sales database excluding exports and mining sales was tested against GDP expressed at constant prices.
- The sales data from NamPower's Annual Reports was converted to a calendar basis and tested against GDP expressed at constant prices and the reported average price of power in Namibia converted to a constant price basis.
- Sales data from NamPower's Annual Reports was converted to a calendar basis and tested against GDP expressed at constant prices, the reported average price of power in Namibia converted to a constant price basis as well as the estimated total annual population figures (based on census data points).

Overall sales have a long-term growth rate of 3.1 percent per annum over the 1990 to 2014 period. Namibian GDP has achieved a long-term growth rate of 4.4 percent per annum over the same period. Total sales display a strong correlation with total GDP with a coefficient of determination of 0.98. Figure 5-4 shows the annual GDP and electricity sales data for the period 1990 to 2014.

Unfortunately, the regression analysis could not identify a statistically valid regression model that includes the price variable or the national population. For both variables the relationship to sales was not significant and in fact the price variable was also of the wrong sign. As a result, the base linear regression of sales versus constant price GDP was used to estimate the organic growth over the forecast period.

The equation used is:

Sales (GWh) = 551.77 + 0.0386 * GDP(N$ millions)
(44.80) (0.00105)
t=12.3 t=36.7
n=25

Sales and GDP are expressed on a calendar year basis.

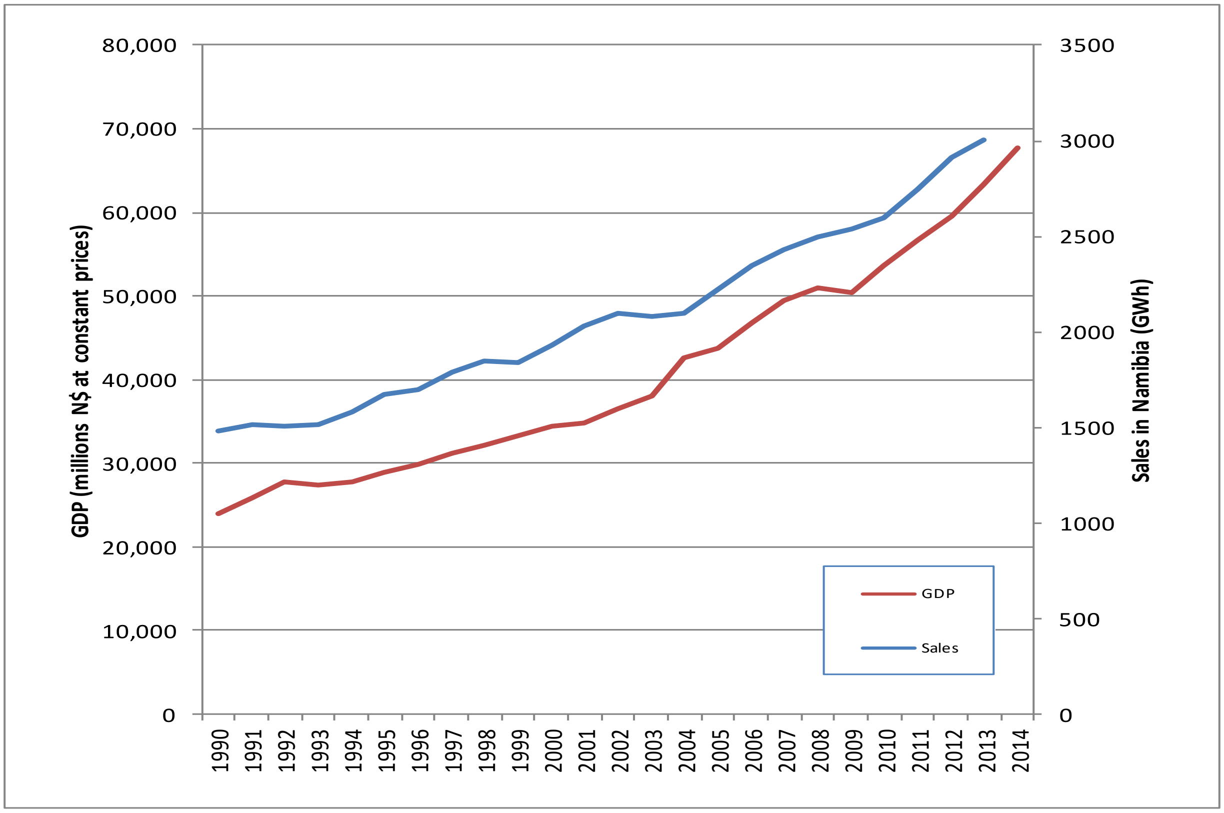

Figure 5-4: Historic GDP and Sales Data

5.4.5 Development Options – Step Loads

As a result of interviews with NamPower, the distributors and several large industries, a number of specific new loads were determined based on a number of planned developments and expansions. The new loads attributed to the distributors are considered likely to develop in one form or another. The mining expansion plans and new developments are largely dependent upon the future demand for and the commodity price of uranium, copper and gold.

Mining

The development of the Husab Mine, adjacent to the Rössing facility, is well advanced in terms of construction and pre-operational mining activities. It is assumed to proceed in both the reference and high scenarios.

The step load list also includes a number of diamond, phosphate, gold and copper properties as well as a smelter. Some of these have been included in all scenarios and some are included only in the high load forecast scenario. The step loads for the mining sector are listed in Table 5-11.

Each step load is assigned a probability category. This probability does not necessarily apply to an individual load but rather to the group as a whole. As a group, loads with a high probability have been assigned a probability value of 75 percent. Medium probability assumes a 50 percent value and low probability a 35 percent value.

Table 5-11: Mining Step Loads

			Load	Load	Start	Last
Scenarios	**Load Name**	**Prob**	**(MW)**	**Factor**	**Year**	**Year**
All	Husab Mine (Years 2017-2023)	H	44.10	0.75	2017	2023
All	Husab Mine (Years 2024-2031)	H	44.10	0.75	2024	2031
All	Husab Mine (Years 2032-2036)	H	44.10	0.75	2032	2036
All	Namibia Custom Smelter (NCS)	H	25.00	0.75	2016	2099
All	Navachab	H	8.50	0.75	2016	2099
Ref & High	Calueque Dam	M	4.50	0.75	2017	2099
Ref & High	Lofdal Mine	M	3.50	0.75	2019	2099
High	B2 Gold	L	14.00	0.75	2019	2099
High	Congo Africa (Kombat Copper)	L	7.20	0.75	2017	2099
High	Gergarub Mine	L	19.00	0.75	2018	2099
High	Lodestone Namibia (Dordabis)	L	14.40	0.75	2019	2099
High	Mertens Mining	L	4.50	0.75	2018	2099
High	Okanjande Graphite Mine	L	2.85	0.75	2018	2099
High	Omitiomire	L	3.80	0.75	2018	2099
High	Zhonghe Resources	L	9.50	0.75	2020	2099

Water Pumping

The water pumping step loads include a desalination plant as well as a pumping load associated with the Husab mine development. The water pumping step loads are listed in Table 5-12. All water pumping loads are assigned to the high probability category with an assumed probability value of 75 percent.

Table 5-12: Water Pumping Step Loads

			Load	Load	Start	Last
Scenarios	**Load Name**	**Prob**	**(MW)**	**Factor**	**Year**	**Year**
All	Erongo Desalination Company (EDC)	H	2.70	0.60	2016	2099
All	Aussenkehr Upgrade	H	3.17	0.60	2016	2099
All	NamWater Swakop South (for Husab)	H	2.85	0.60	2016	2099

Commercial/Industrial

The step loads in this category (see Table 5-13) range from shopping centres to a major port expansion at Walvis Bay. The category also includes the Mass Housing Program (MHP) proposed by the Government of Namibia. There are few details available for this program. As a result, the following general variables have been assumed. For the reference scenario it has been assumed that 3,000 households will be added each year over the 15-year period from 2015 to 2030. Each household is expected to consume 2,500 kWh per year and generate a 1.5 kW impact on system peak demand. For the high scenario, it has been assumed that 6,500 households will be added each year and for the low scenario there are 1,500 additional households annually.

Parallel to the MHP is the proposed electrification of peri-urban households. The majority of these households are informal houses which will be replaced with proper houses, possibly included under the MHP. No explicit adjustment above the assumed MHP electrification is included in the forecast at this time.

Table 5-13: Commercial/Industrial Step Loads

Scenario	Load Name	Prob	Load (MW)	Load Factor	Start Year	Last Year
All	Lady Pohamba Private Hospital	H	1.97	0.60	2016	2099
All	Karasburg upgrade	H	0.90	0.60	2017	2099
All	Brakwater development	H	3.60	0.60	2016	2099
All	Cuito Upgrade	H	5.40	0.60	2018	2099
All	Erongo Red NamPort (Port extension)	H	13.00	0.60	2017	2099
Ref & High	Cuando Cubango	M	5.10	0.60	2018	2099
Ref & High	Okombahe Upgrade	M	0.95	0.60	2018	2099
Ref & High	Ruby Upgrade	M	3.80	0.60	2016	2099
All	Otavi Rebar	L	31.50	0.60	2018	2099
Ref	Mass Housing Program – Years 2016-2020	M	67.5	0.20	2016	2020
Ref	Mass Housing Program – Years 2021-2025	M	67.5	0.20	2021	2025
Ref	Mass Housing Program – Years 2026-2099	M	67.5	0.20	2026	2099
Low	Mass Housing Program – Years 2016-2020	L	33.8	0.20	2016	2020
Low	Mass Housing Program – Years 2021-2025	L	33.8	0.20	2021	2025
Low	Mass Housing Program – Years 2026-2099	L	33.8	0.20	2026	2099
High	Mass Housing Program – Years 2016-2020	L	146.3	0.20	2016	2020
High	Mass Housing Program – Years 2021-2025	L	146.3	0.20	2021	2025
High	Mass Housing Program – Years 2026-2099	L	146.3	0.20	2026	2099

5.4.6 Demand Side Management Programs and Renewable Energy

A number of DSM programs are included in the forecast. There are three specific areas addressed in these programs:

- LED Lighting - NamPower's DSM program includes the distribution of one million LED light bulbs as replacement for incandescent bulbs. The operational assumptions include that a 40 W incandescent bulb will be replaced by a 5 W LED bulb for a net saving of 35 W per replacement. Each bulb is assumed to be illuminated for 5 hours per day and that the illumination will be at an 80 percent coincidence to the system peak.
- Solar Thermal – NamPower has also considered a program that would replace 20,000 electric water heaters with solar heaters. While it is understood that NamPower is re-evaluating this program, other agencies such as the Namibia Energy Institute are actively involved in this area. This program has been included in the forecast as it is considered that such replacements would likely eventually be undertaken by consumers with or without the NamPower program. For the forecast it is assumed that this replacement will occur over ten years and that each unit replaced has a peak of 2.5 kW at a load factor of 0.25. The units are also assumed to operate at a 20 percent coincidence to the system peak.
- Solar PV – The expectation is that the current trend of behind the meter installations of solar PV panels will continue. There are no official surveys providing estimates of the number of solar PV installations currently in use or on the projected number of future installations. It has been assumed that in each forecast year an additional 5 MW of solar PV capacity will be installed with an expected load factor of 0.20. It is also assumed that these installations will not impact the system peak demand as the system peak load is

typically in the early evening when solar PV production is at, or close to, zero. It is noted that additional solar PV installations are included in the generation analysis.

5.5 Forecast Results

5.5.1 Forecast Summary

Three forecast scenarios have been prepared based on the growth rates presented in the previous sub-sections. The Low, Reference and High sales forecast results are listed in Table 5-14. The table shows the historical sales for 2014, the estimate for 2015 and the remaining years of the forecast to 2035. The corresponding energy generation and peak demand values are presented in Table 5-15. It is expected that the shape of the daily load curve will not change significantly over the forecast period. The annual peak demand has typically been recorded during the evening hours in the months of June or July (for example between 7 and 8 PM on June 2 for the year 2014/2015). While increasing LED lighting will have a moderating impact on the peak demand, increasing the amount of behind the meter solar PV will reduce the need for grid supply during daylight hours but will not impact the evening peak demand.

The Low, Reference and High forecast results are also displayed in Figure 5-5 -and Figure 5-6 in terms of the energy sales forecast and the peak demand forecast, respectively.

Table 5-14: Sales Forecast Summary

Year	Low Sales (GWh)	Reference Sales (GWh)	High Sales (GWh)
2014	3,184	3,184	3,184
2015	3,387	3,402	3,413
2016	3,692	3,728	3,755
2017	3,927	3,998	4,050
2018	4,099	4,201	4,311
2019	4,196	4,333	4,556
2020	4,320	4,483	4,789
2021	4,461	4,647	5,001
2022	4,572	4,784	5,163
2023	4,688	4,927	5,334
2024	4,823	5,091	5,529
2025	4,966	5,265	5,735
2026	5,115	5,446	5,951
2027	5,280	5,647	6,189
2028	5,445	5,849	6,432
2029	5,616	6,060	6,685
2030	5,795	6,281	6,953
2031	5,980	6,508	7,227
2032	6,137	6,711	7,480
2033	6,337	6,959	7,783
2034	6,517	7,190	8,073
2035	6,733	7,461	8,407
2015-2035	3.50%	4.00%	4.61%

Table 5-15: Generation Forecast Summary

	Low		Reference		High	
Year	**Energy**	**Peak**	**Energy**	**Peak**	**Energy**	**Peak**
	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)
2014	3,654	554.0	3,654	554.0	3,654	554.0
2015	3,853	597.0	3,871	597.0	3,883	597.0
2016	4,200	638.2	4,241	645.7	4,272	651.1
2017	4,468	678.3	4,549	692.5	4,608	702.9

2018	4,664	712.3	4,780	733.4	4,905	754.3
2019	4,774	730.1	4,930	758.4	5,184	800.9
2020	4,916	752.3	5,100	785.9	5,448	842.1
2021	5,076	777.2	5,288	815.9	5,689	880.6
2022	5,202	797.6	5,443	841.7	5,875	911.8
2023	5,334	818.8	5,606	868.5	6,069	944.0
2024	5,488	843.0	5,793	898.8	6,291	980.4
2025	5,651	868.6	5,991	930.7	6,526	1,018.7
2026	5,819	895.2	6,197	963.8	6,771	1,058.4
2027	6,007	925.3	6,425	1,001.0	7,042	1,102.9
2028	6,195	955.5	6,655	1,038.7	7,318	1,148.3
2029	6,390	986.8	6,895	1,077.6	7,606	1,195.3
2030	6,594	1,019.4	7,147	1,118.5	7,911	1,244.9
2031	6,803	1,052.4	7,405	1,158.7	8,223	1,293.2
2032	6,982	1,081.4	7,636	1,195.4	8,511	1,338.6
2033	7,210	1,117.0	7,918	1,239.3	8,855	1,391.7
2034	7,415	1,149.7	8,181	1,280.7	9,185	1,443.2
2035	7,661	1,188.1	8,490	1,328.5	9,565	1,501.7
2015-2035	3.50%	3.50%	4.00%	4.08%	4.61%	4.72%

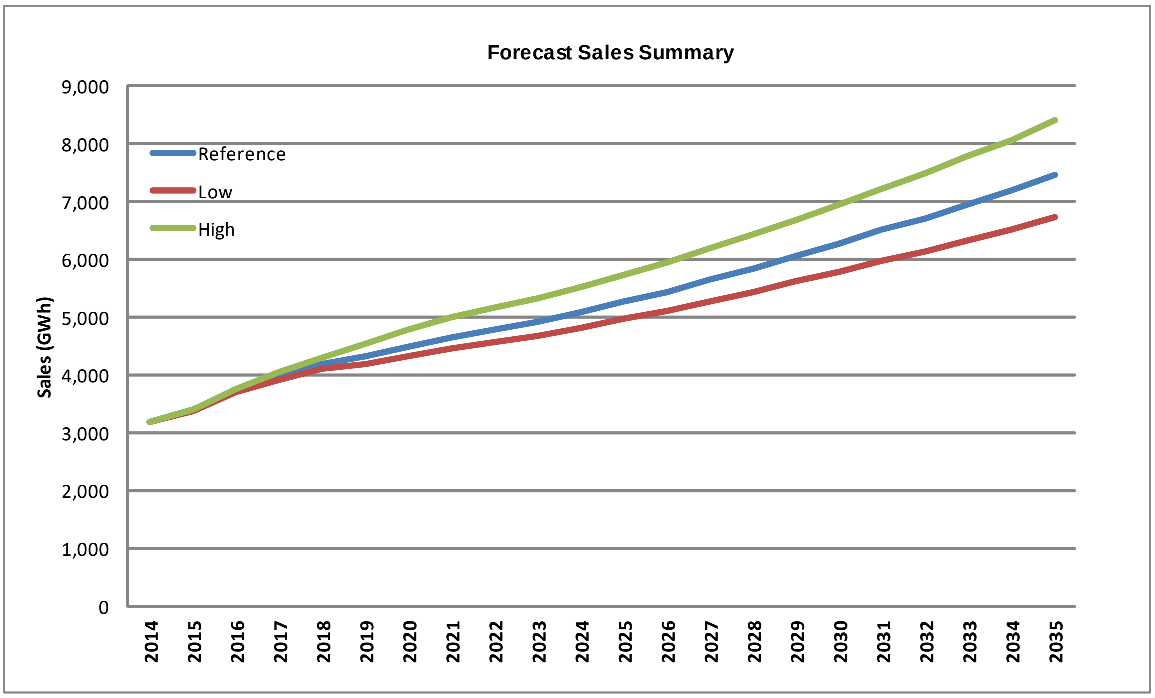

Figure 5-5: Overall Sales Forecasts – Energy (GWh)

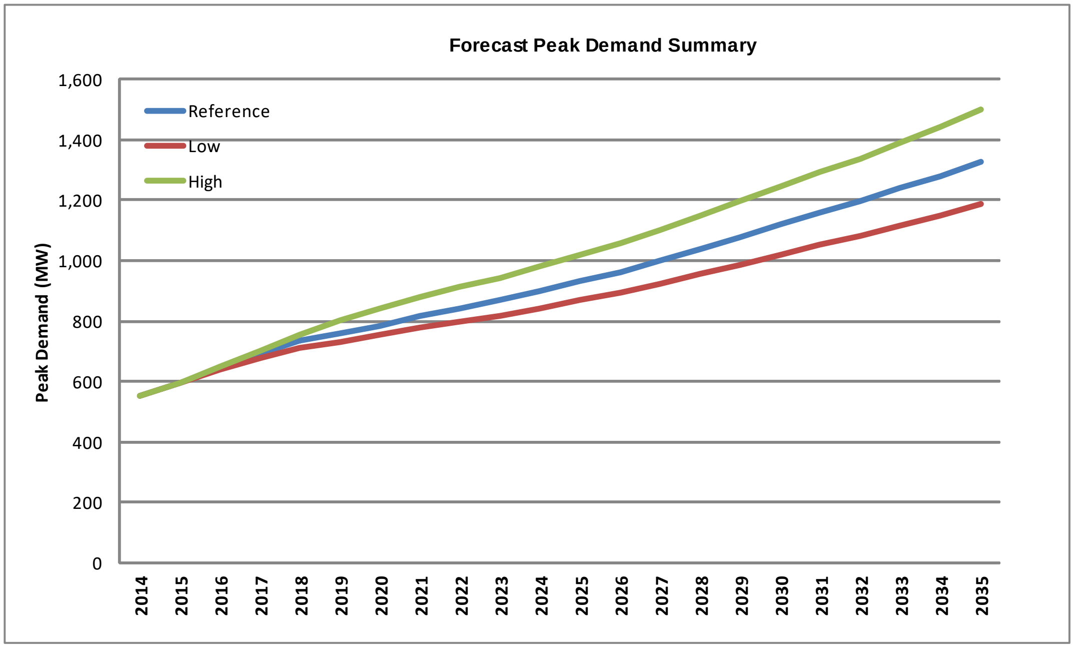

Figure 5-6: Overall Generation Forecasts – Peak Demand (MW)

5.5.2 Reference Forecast

The overall growth rate in the reference scenario is 4.0 percent over the entire forecast period to 2035. This compares to the historical long term growth rate of 3.1 percent.

Table 5-16 sumarises the reference forecast in terms of both sales and generation energy (GWh) and peak demand (MW). Figure 5-7 compares the reference energy forecast for both sales and generation.

Table 5-16: Reference Forecast Summary

Year	Sales Energy (GWh)	Generation Energy (GWh)	Generation Peak (MW)
2014	3,184	3,654	554.0
2015	3,402	3,871	597.0
2016	3,728	4,241	645.7
2017	3,998	4,549	692.5
2018	4,201	4,780	733.4
2019	4,333	4,930	758.4
2020	4,483	5,100	785.9
2021	4,647	5,288	815.9
2022	4,784	5,443	841.7
2023	4,927	5,606	868.5
2024	5,091	5,793	898.8
2025	5,265	5,991	930.7
2030	6,281	7,147	1,118.5
2035	7,461	8,490	1,328.5
2015-2035	4.00%	4.00%	4.08%

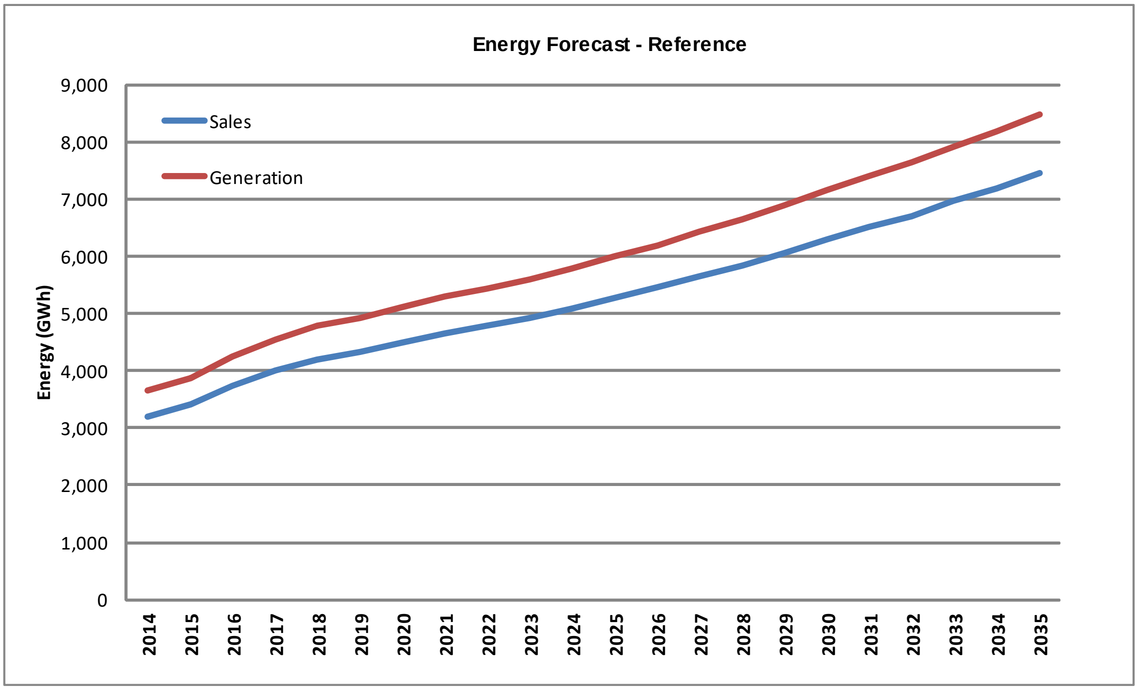

Figure 5-7: Reference Sales and Generation (GWh)

Table 5-17 presents the forecast components in energy (GWh) terms. The forecast is segregated into the organic load – the load that is currently defined on the system and further development of that load over time - and the step loads, new loads that are considered too large to be associated with organic growth as well as the DSM reduction. The average growth in the organic load is 3.88 percent. The table also displays the estimated transmission losses.

Table 5-17: Reference Forecast Energy Components (GWh)

Year	Sales Organic (GWh)	Sales Step (GWh)	DSM Reduction (GWh)	Sales Total (GWh)	Transmission Losses (GWh)	Generation Total (GWh)
2014	3,184	0	0	3,184	470	3,654
2015	3,402	0	0	3,402	469	3,871
2016	3,552	200	-24	3,728	514	4,241
2017	3,697	352	-51	3,998	551	4,549
2018	3,832	448	-78	4,201	579	4,780
2019	3,973	466	-106	4,333	597	4,930
2020	4,119	496	-133	4,483	618	5,100
2021	4,273	535	-160	4,647	640	5,288
2022	4,433	539	-188	4,784	659	5,443
2023	4,600	543	-215	4,927	679	5,606
2024	4,774	560	-243	5,091	702	5,793
2025	4,956	579	-270	5,265	725	5,991
2030	5,994	605	-318	6,281	865	7,147
2035	7,280	542	-361	7,461	1,028	8,490
2015-2035	3.88%			4.00%		4.00%

The development of the Organic, Step, DSM and Transmission portions of the reference energy forecast are displayed in Figure 5-8. Figure 5-9 displays the forecast path for the organic and total sales over the entire forecast period.

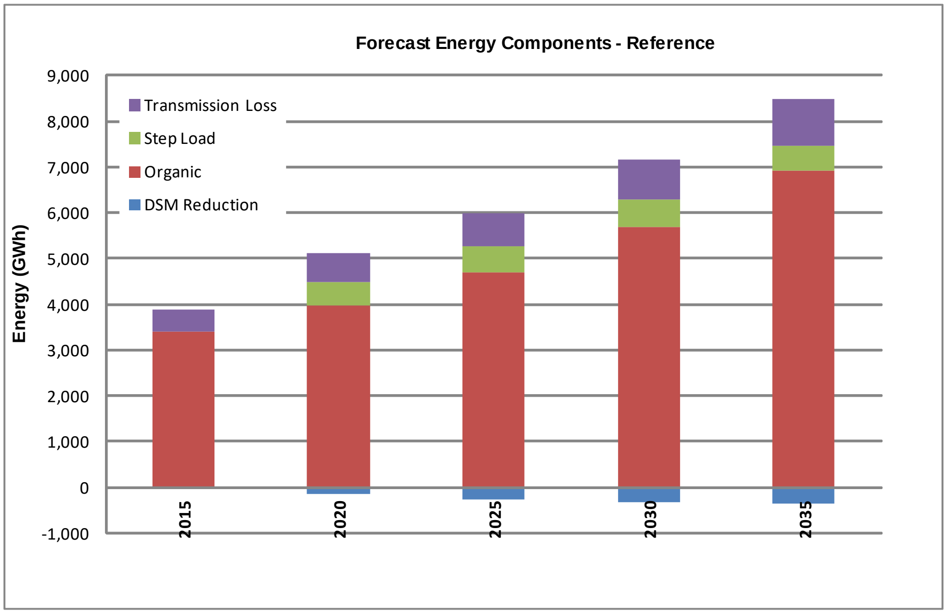

Figure 5-8: Reference Forecast Components (GWh)

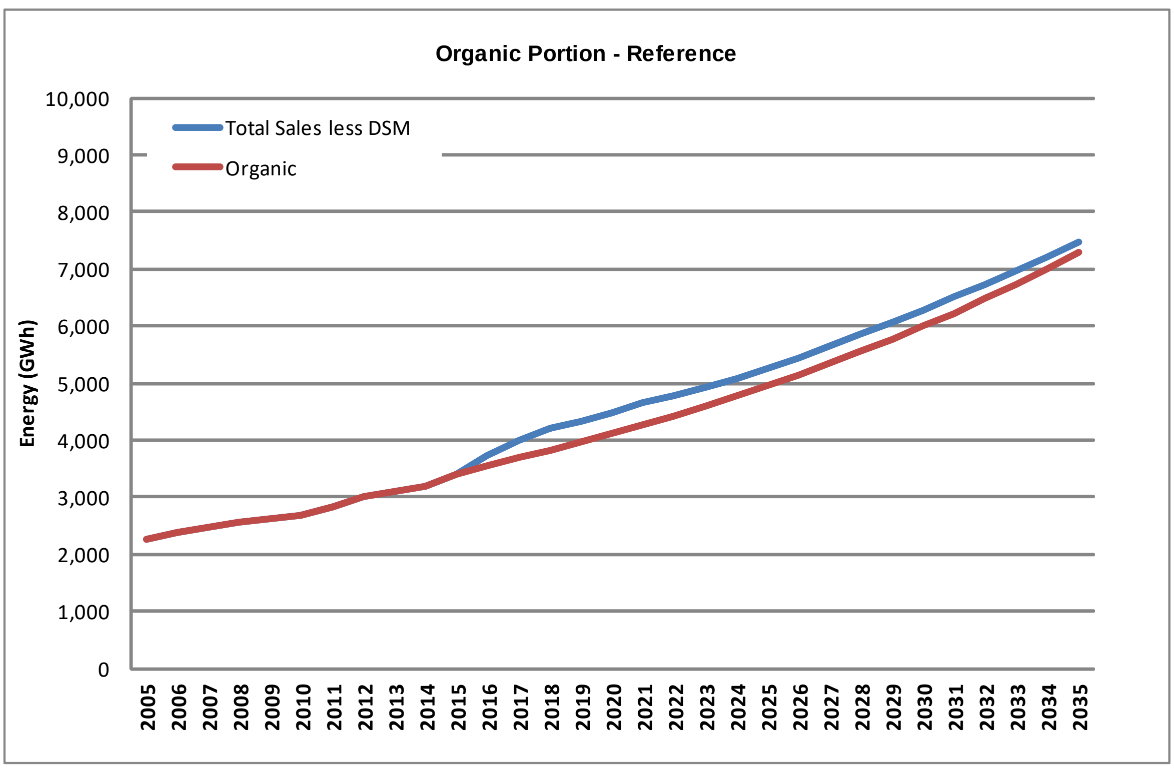

Figure 5-9: Reference Forecast – Organic vs. Total Sales (GWh)

5.5.3 Low Scenario

The low scenario assumes the pessimistic GDP forecast and the expectation that lower uranium prices will not induce significant new uranium mining developments, thus limiting the mining step loads.

The overall growth rate in the low scenario is 3.5 percent over the entire forecast period to 2035.

Table 5-18 sumarises the low forecast in terms of both sales and generation energy (GWh) and peak demand (MW). Figure 5-10 displays the low energy forecast for both sales and generation.

Table 5-18: Low Forecast Summary (GWh)

Year	Sales Energy (GWh)	Generation Energy (GWh)	Generation Peak (MW)
2014	3,184	3,654	554.0
2015	3,387	3,853	597.0
2016	3,692	4,200	638.2
2017	3,927	4,468	678.3
2018	4,099	4,664	712.3
2019	4,196	4,774	730.1
2020	4,320	4,916	752.3
2021	4,461	5,076	777.2
2022	4,572	5,202	797.6
2023	4,688	5,334	818.8
2024	4,823	5,488	843.0
2025	4,966	5,651	868.6
2030	5,795	6,594	1,019.4
2035	6,733	7,661	1,188.1
2015-2035	3.50%	3.50%	3.50%

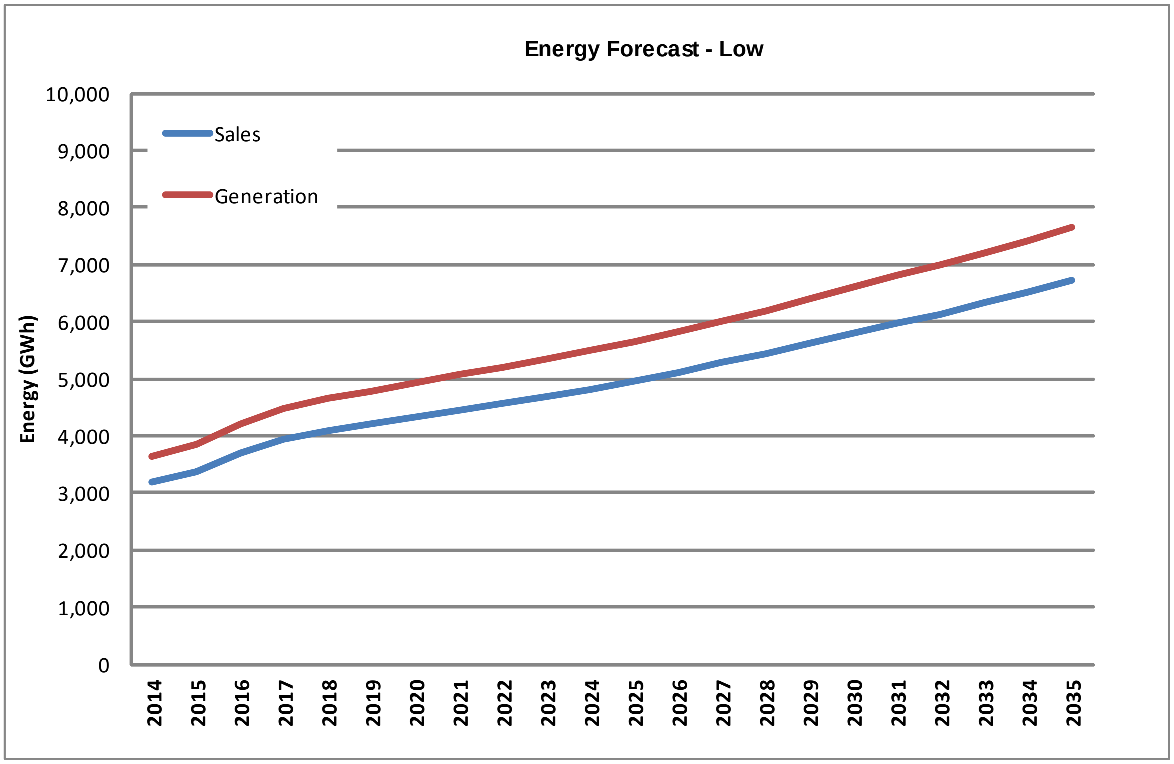

Figure 5-10: Low Sales and Generation (GWh)

Table 5-19 presents the forecast energy components. The forecast is segregated into the organic load – the load that is currently defined on the system - and the step loads as well as the estimated DSM reduction and transmission losses. The average growth in the organic load is 3.4 percent.

Table 5-19: Low Forecast Energy Components (GWh)

Year	Sales Organic (GWh)	Sales Step (GWh)	DSM Reduction (GWh)	Sales Total (GWh)	Transmission Losses (GWh)	Generation Total (GWh)
2014	3,184	0	0	3,184	470	3,654
2015	3,387	0	0	3,387	467	3,853
2016	3,521	194	-24	3,692	509	4,200
2017	3,651	327	-51	3,927	541	4,468
2018	3,769	409	-78	4,099	565	4,664
2019	3,891	411	-106	4,196	578	4,774
2020	4,018	436	-133	4,320	595	4,916
2021	4,150	472	-160	4,461	615	5,076
2022	4,287	473	-188	4,572	630	5,202
2023	4,429	475	-215	4,688	646	5,334
2024	4,577	489	-243	4,823	665	5,488
2025	4,730	506	-270	4,966	684	5,651
2030	5,593	519	-318	5,795	798	6,594
2035	6,638	456	-361	6,733	928	7,661
2015-2035	3.4%			3.5%		3.5%

The development of the Organic, Step, DSM and Transmission portions of the low forecast are displayed in Figure 5-11. Figure 5-12 displays the forecast path for the organic and total sales components over the entire forecast period.

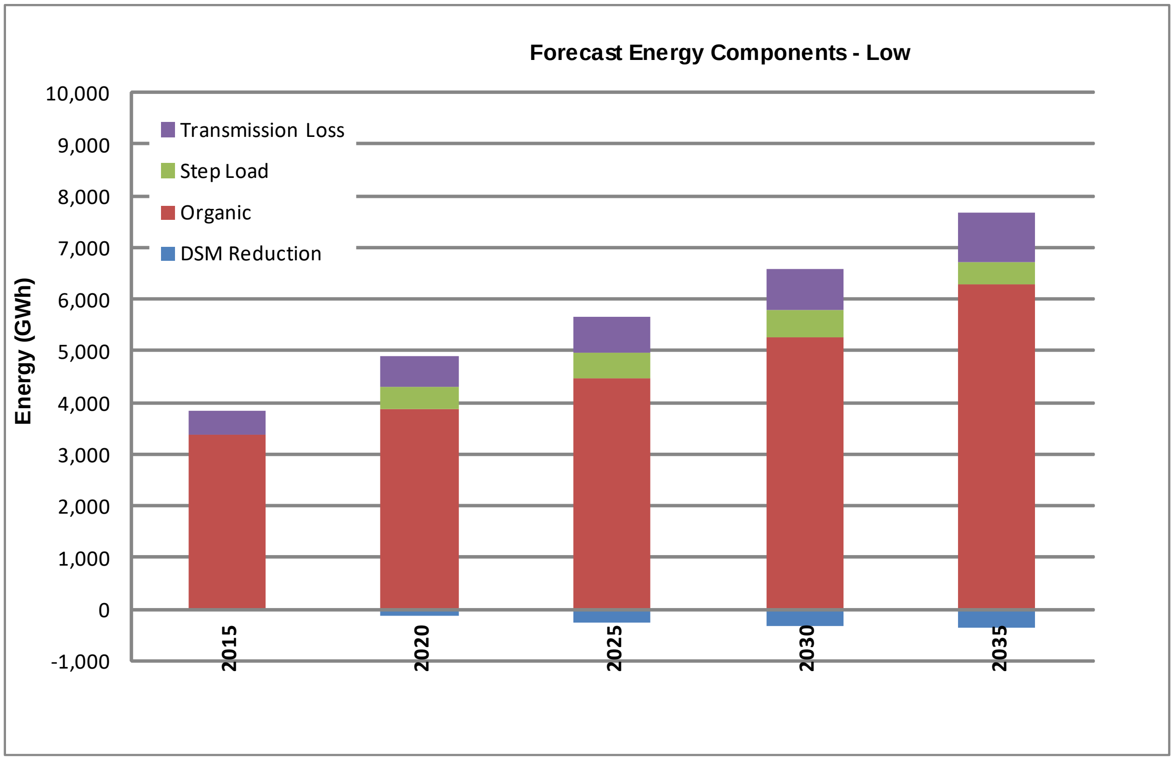

Figure 5-11: Low Forecast Components (GWh)

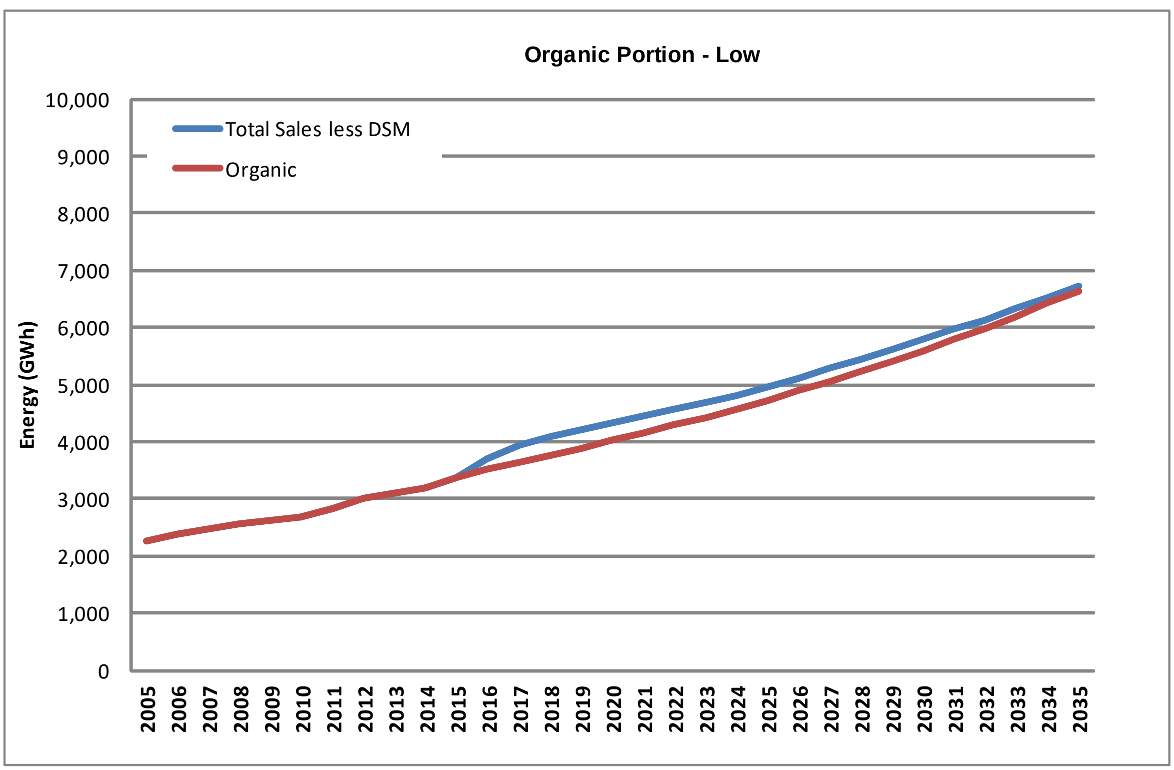

Figure 5-12: Low Forecast Organic vs. Total Sales (GWh)

5.5.4 High Scenario

The high scenario assumes the optimistic GDP forecast and the expectation that uranium prices will be higher and therefore will encourage additional mining developments leading to more step loads.

The overall growth rate in the high scenario is 4.61 percent over the entire forecast period to 2035.

Table 5-20 sumarises the high forecast in terms of both sales and generation energy (GWh) and peak demand (MW). Figure 5-13 displays the high energy forecast for both sales and generation.

Table 5-20: High Forecast Summary (GWh)

Year	Sales Energy (GWh)	Generation Energy (GWh)	Generation Peak (MW)
2014	3,184	3,654	554.0
2015	3,413	3,883	597.0
2016	3,755	4,272	651.1
2017	4,050	4,608	702.9
2018	4,311	4,905	754.3
2019	4,556	5,184	800.9
2020	4,789	5,448	842.1
2021	5,001	5,689	880.6
2022	5,163	5,875	911.8
2023	5,334	6,069	944.0
2024	5,529	6,291	980.4
2025	5,735	6,526	1,018.7
2030	6,953	7,911	1,244.9
2035	8,407	9,565	1,501.7
2015-2035	4.61%	4.61%	4.72%

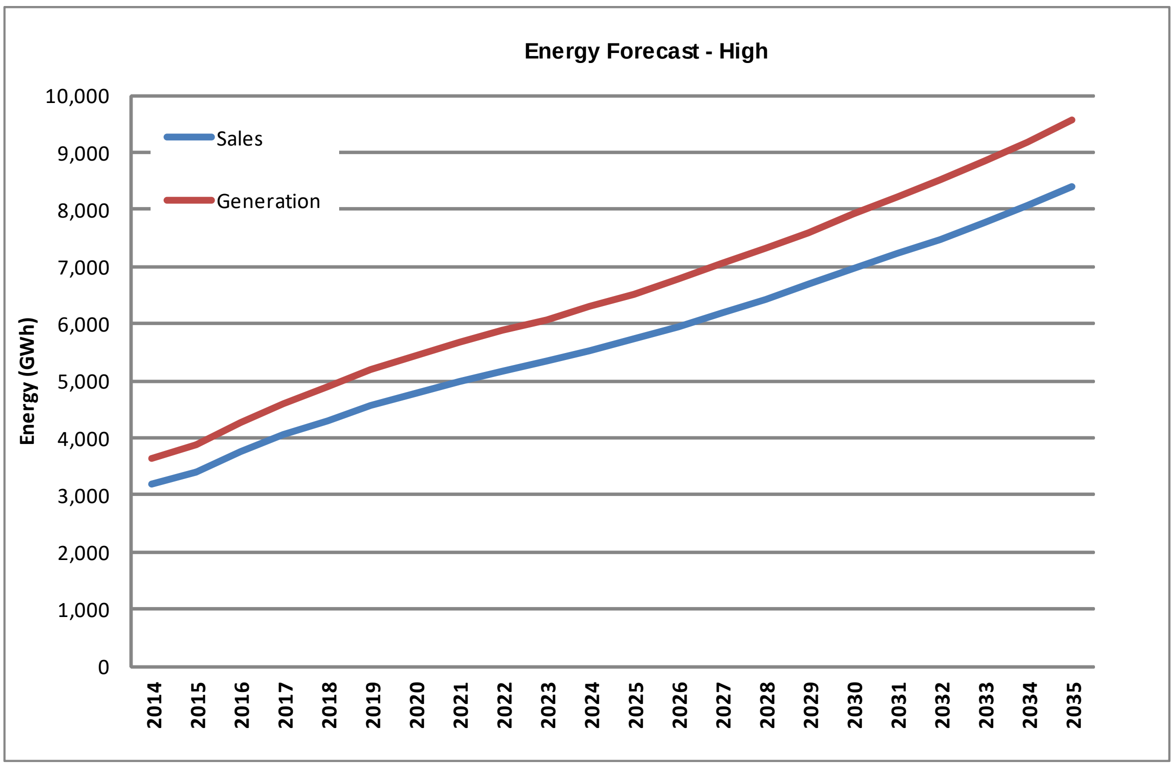

Figure 5-13: High Sales and Generation (GWh)

Table 5-21 presents the forecast summary in energy (GWh). The forecast is segregated into the organic load – the load that is currently defined on the system - and the step loads as well as the estimated DSM reduction and the transmission losses. The average growth in the organic load is 4.3 percent.

Table 5-21: High Forecast Energy Components (GWh)

Year	Sales Organic (GWh)	Sales Step (GWh)	DSM Reduction (GWh)	Sales Total (GWh)	Transmission Losses (GWh)	Generation Total (GWh)
2014	3,184	0	0	3,184	470	3,654
2015	3,413	0	0	3,413	470	3,883
2016	3,576	202	-24	3,755	517	4,272
2017	3,738	363	-51	4,050	558	4,608
2018	3,890	499	-78	4,311	594	4,905
2019	4,050	612	-106	4,556	628	5,184
2020	4,217	705	-133	4,789	660	5,448
2021	4,392	769	-160	5,001	689	5,689
2022	4,576	775	-188	5,163	711	5,875
2023	4,769	780	-215	5,334	735	6,069
2024	4,972	800	-243	5,529	762	6,291
2025	5,184	821	-270	5,735	790	6,526
2030	6,413	857	-318	6,953	958	7,911
2035	7,974	794	-361	8,407	1,158	9,565
2015-2035	4.3%			4.6%	470	4.6%

The development of the Organic, Step, DSM and Transmission portions of the peak high forecast are displayed in Figure 5-14. Figure 5-15 displays the forecast path for the organic and step load components over the entire forecast period.

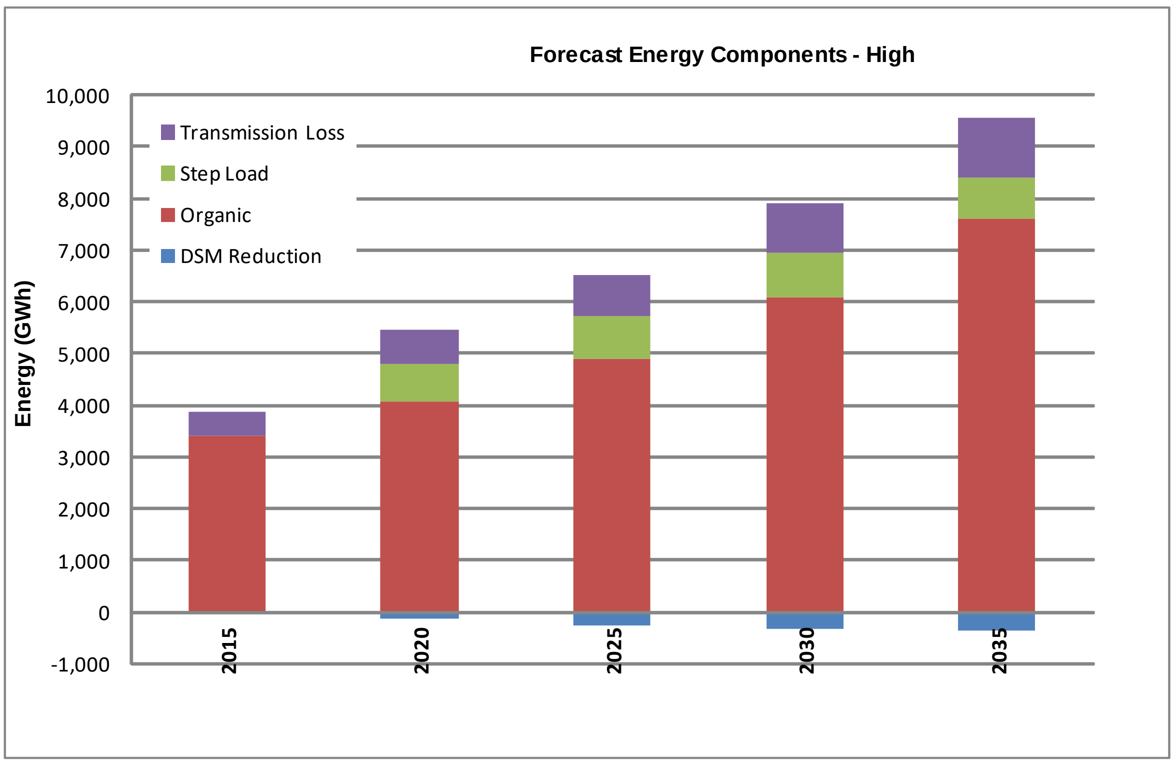

Figure 5-14: High Forecast Components (GWh)

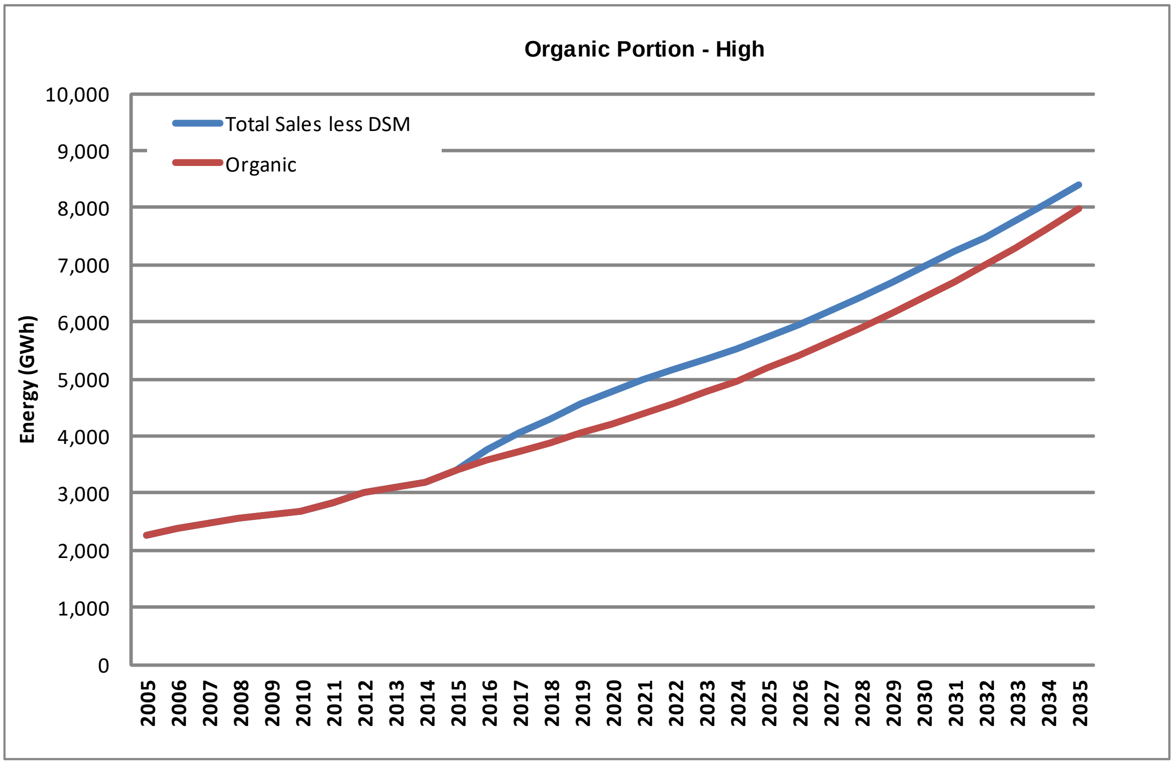

Figure 5-15: High Forecast Organic vs. Total Sales (GWh)

5.6 Supply-Demand Balance

Comparing the generation supply capability with the projected demand as developed in the load forecast provides an indication of the balance between the two. For these comparisons, supply includes existing and committed power plants in Namibia, import contracts and projected retirements of generation capacity. Supply-demand balances for both energy (kWh) and capacity (MW) are important as either or both can be constraints at different times of the year if there are seasonal variations in supply and/or load.

The projected monthly energy and capacity balances over the next four years, i.e. from 2016 to 2019 are graphically illustrated in Figure 5-16, Figure 5-17 and Figure 5-18. It is important to note that the supply energy and capacity are the maximum amounts which could be achieved, i.e. no allowances have been made for planned or forced outages of power plants, interruption of imports under import contracts and for reserve capacity. It is also possible that there are circumstances where system load demand is relatively low but the supply capacity is relatively high, resulting in a situation where the supply capacity could not be fully utilised.

Figure 5-16 and Figure 5-17 show the monthly energy and capacity balances, taking into account all domestic power plants and import contracts. One could see from these two figures that the system would experience energy shortages during several months of a year while the available capacity is relatively adequate.

Figure 5-18 shows the monthly energy and capacity balances based on the requirements of the White Paper on Energy Policy. Relative to the requirements of the Energy Policy, the system would be short of both energy and capacity over all months of the four years.

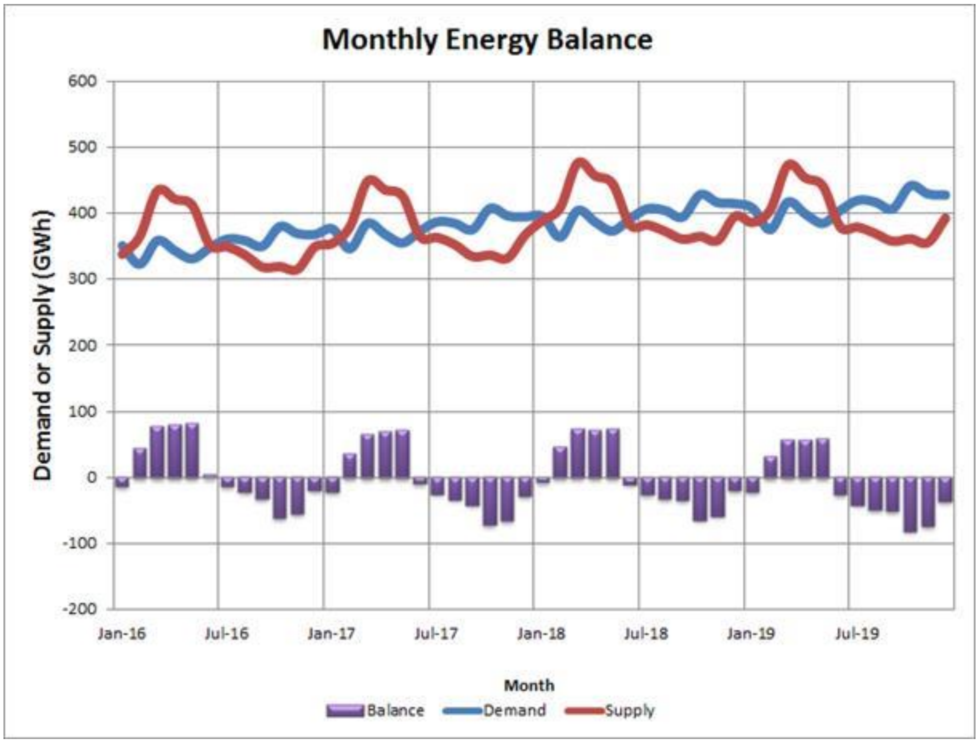

Figure 5-16: Monthly Energy Balance – All Inclusive

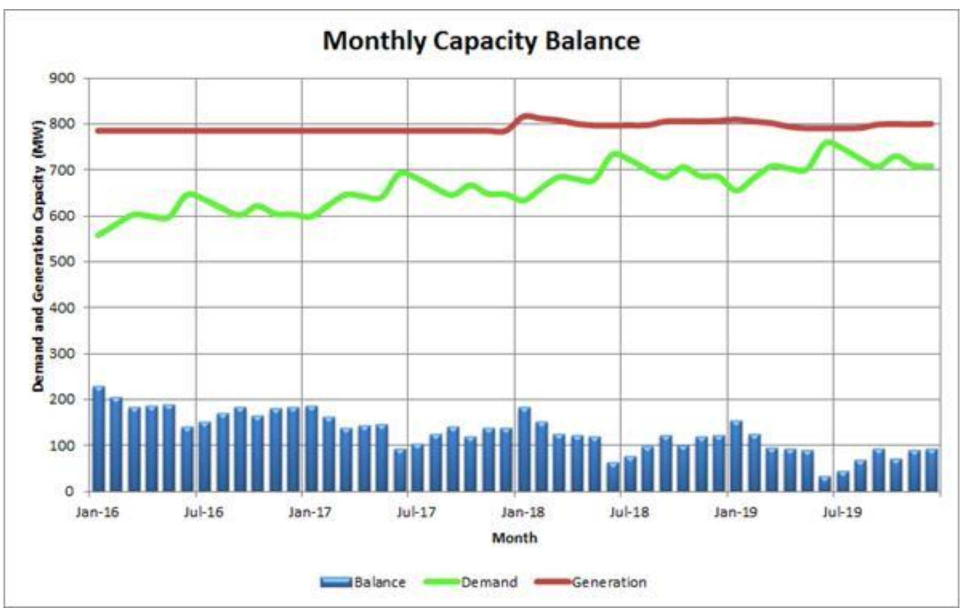

Figure 5-17: Monthly Capacity Balance – All Inclusive

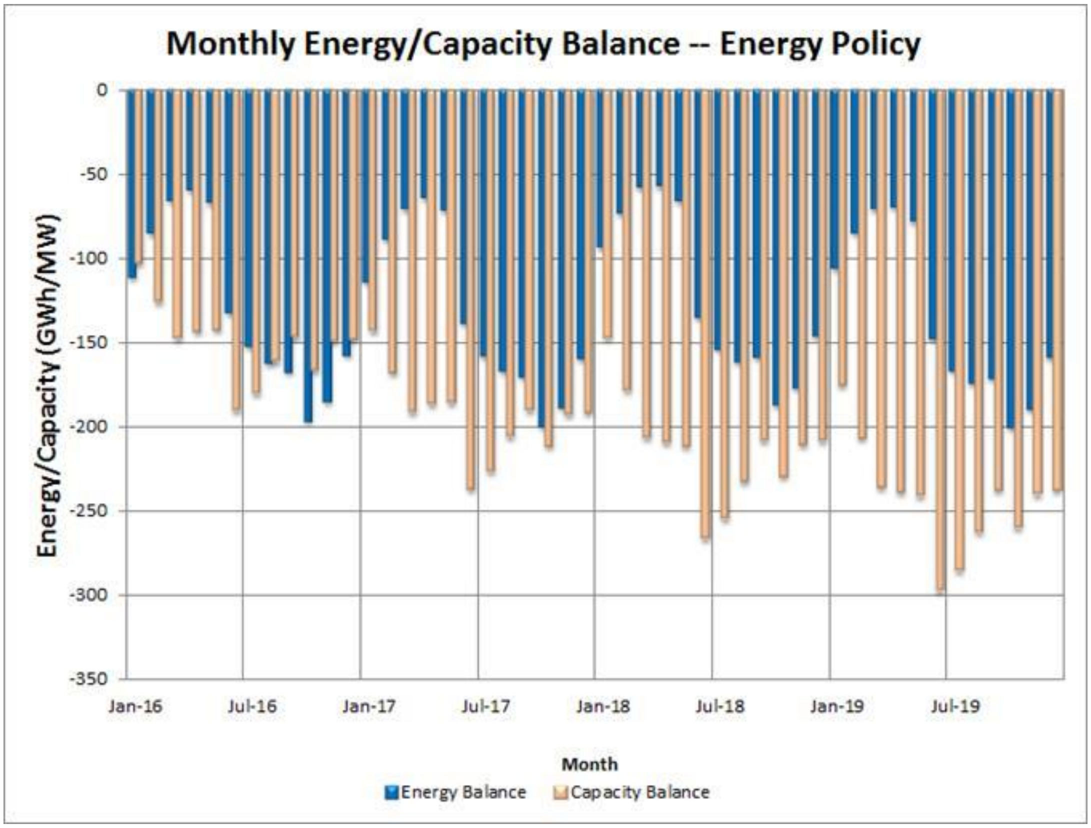

Figure 5-18: Monthly Energy Capacity Balance – Energy Policy

6. Formulation of Expansion Scenarios

6.1 Evaluation of Available Generation Options

Based on the information on generation resources and technologies described in Section 1, one could conclude that for this assignment, no further consideration need be given to generation from conventional nuclear, water power on the Okavango and Orange river systems, small modular nuclear reactors, municipal solid waste and geothermal. The remaining generation options could be divided into the following six categories:

1. Conventional base load – NG CCGT 450 MW, LNG CCGT 150 MW, LNG GT 50 MW, LNG GT 100 MW, Coal CFB 150 MW, Coal PC 150 MW, ICRE 20 MW and LFO CC 150 MW.
2. Conventional peaking – ICRE 20 MW, LFO GT 50 MW, LFO GT 100 MW.
3. Dispatchable renewable base load and mid-merit order – Biomass 5 MW, Biomass 10 MW, CSP 50 MW (12 Hour Storage), Biofuel CC 75 MW and Biofuel CC 150 MW.
4. Renewable peaking – Baynes, CSP 50 MW (4 Hour Storage), CSP 50 MW (8 Hour Storage).
5. Intermittent renewable – Wind 50 MW, Solar PV 10 MW and CSP 50 MW (No Storage).
6. Imports (including base load, peaking and off-peak from various sources).

This section presents a screening analysis of the generation options listed above. The main purpose of this screening process is to identify the options that are clearly not economic and as such should not be included in the formulation of generation expansion scenarios.

6.2 Screening Curves and Selection of Generation Options

At the screening stage, a reasonable way to compare generation options is to make a comparison of the unit cost of energy produced by each generation option including capital costs, operation and maintenance costs and fuel costs (if any). It is noted that the GHG offset allowance cost has not been included in the screening analysis (but will be included in the latter stages of the analysis).

Each of the above generation categories has its own peculiarities when comparing the unit cost of energy including life of plant and operating characteristics. The unit cost of energy for each generation category presented in the following subsections harmonises these parameters such that realistic comparisons can be made.

6.2.1 Unit Cost of Energy for Conventional Base Load Plants

Section 1 presents several conventional generation options that are suitable for base load duty using such fuels as natural gas, coal and petroleum based products. For each of these fuels there are one or more technologies that could be used. Based on the technical and economic parameters provided in Section 1 and the estimated cost of fuels, this section determines the levelised unit cost of energy for each of these options. The combination of technologies and fuels results in eight possible conventional base load plant types/sizes as shown in Table 6-1.

When determining the unit cost of energy, one has to specify the capacity factor and since, at this stage, the amount to be dispatched is unknown, the costs for a range of capacity factors are shown in Table 6-1.

Figure 6-1 presents in a graphic form the results of Table 6-1 for the selected options while Figure 6-2 presents the cost in N$/kW-Year which represents the total cost for each kW for a year depending on the number of hours that a unit is operated (the greater number of hours, the higher the cost).

Table 6-1: Unit Cost of Energy (N$/kWh) for Conventional Base Load Plants at Various Capacity Factors

Plant Factor (%)	Natural Gas				Coal		HFO	LFO
	CC		GT		CFB	PC	ICRE	CC
	450 MW	150 MW	50 MW	100 MW	150 MW	150 MW	20 MW	150 MW
5.0	8.27	8.85	8.50	8.11	12.83	11.56	10.19	9.16
10.0	4.81	5.35	5.42	5.19	6.81	6.16	5.81	5.67
15.0	3.66	4.19	4.39	4.21	4.80	4.36	4.35	4.50
20.0	3.08	3.61	3.87	3.73	3.80	3.46	3.62	3.92
25.0	2.74	3.26	3.57	3.44	3.19	2.92	3.18	3.57
30.0	2.51	3.02	3.36	3.24	2.79	2.56	2.89	3.33
35.0	2.34	2.86	3.21	3.10	2.51	2.30	2.68	3.17
40.0	2.22	2.73	3.10	3.00	2.29	2.11	2.53	3.04
45.0	2.12	2.63	3.02	2.92	2.12	1.96	2.41	2.95
50.0	2.05	2.56	2.95	2.85	1.99	1.84	2.31	2.87
55.0	1.98	2.49	2.89	2.80	1.88	1.74	2.23	2.80
60.0	1.93	2.44	2.85	2.75	1.79	1.66	2.16	2.75
65.0	1.89	2.40	2.81	2.72	1.71	1.59	2.11	2.71
70.0	1.85	2.36	2.77	2.68	1.65	1.53	2.06	2.67
75.0	1.82	2.32	2.74	2.66	1.59	1.48	2.02	2.64
80.0	1.79	2.29	2.72	2.63	1.54	1.44	1.98	2.61
85.0	1.76	2.27	2.70	2.61	1.49	1.40	1.95	2.58
90.0	1.74	2.25	2.68	2.59	1.45	1.36	1.92	2.56
								2.54

Nc

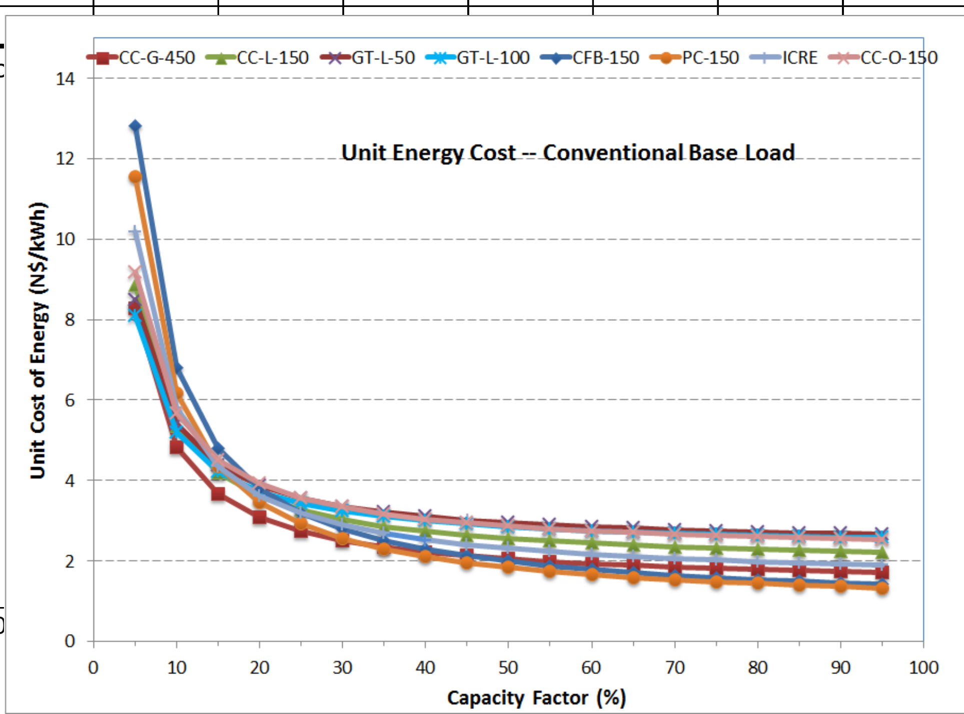

Figure 6-1: Unit Cost of Energy for Conventional Base Load Plants

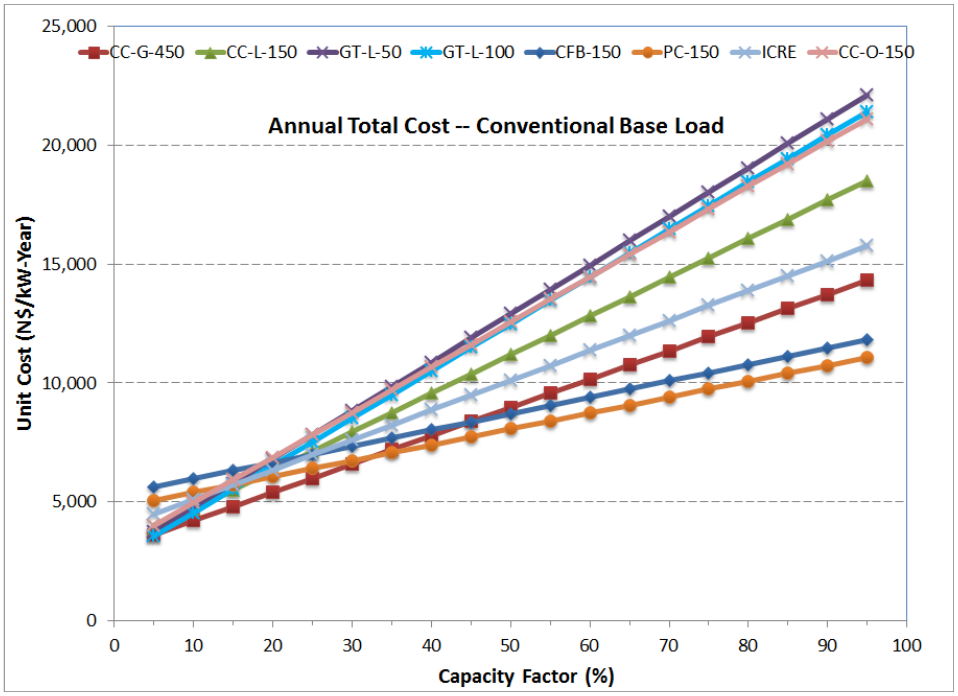

Figure 6-2: Total Annual Costs of Conventional Base Load Plants

For the conventional base load generation technologies at a capacity factor of 80%, one could observe the following from Table 6-1, Figure 6-1and/or Figure 6-2:

1. Coal fired PC 150 MW would have the least unit cost of energy at N$ 1.44/kWh but it would need to have FGD installed at additional cost. It is assumed that the CFB technology would be adopted as it could reduce SO2 emissions and is flexible to use other fuels such as biomass. In this case, the unit cost of energy would increase to N$ 1.54/kWh. The next least cost option is the CC 450 MW fuelled by Kudu natural gas. The three most expensive base load generation options would be LNG GT 50 MW (N$ 2.72/kWh), LNG GT 100 MW (N$ 2.63/kWh) and LFO fuelled CC 150 MW (N$ 2.61/kWh).
2. Comparing the costs for LNG GTs, the unit cost of energy of LNG CC 150 MW would be some N$ 2.29/kWh, which is lower than that for LNG GT 50 MW and LNG GT 100 MW.
3. The unit cost of energy of HFO ICRE 20 MW would be N$ 1.98/kWh, which is lower than that for LFO CC, LNG GTs and LNG CC but higher than that for PC and CFB coal units as well as NG CC units.
4. It is understood that proposals have been made to NamPower that include several GT 50 MW units using LNG to be imported and regasified at a FSRU and the project would be used to supply base load power before a permanent base load plant is commissioned. After the commissioning of such a plant the GT 50 MW units operating on LNG could be either used for backup or removed from the system. In the case of backup, cost of LNG in N$/GJ could be very expensive as the small volume of gas consumption would need to carry the rental and O&M costs of the FSRU.
5. Based the findings above, the next stage analysis will not include such base load generation options as LNG GT 100 MW, PC 300 MW and LFO CC 150 MW. Although the cost of LNG GT 50 MW is also high, it will be included in the further analysis as NamPower has received the proposals referred to above.

6.2.2 Unit Cost of Energy for Conventional Peaking Plants

Gas turbines are usually well suited for peaking duty as are medium speed ICREs. Due to lack of natural gas or very small volume of LNG required for peaking plants, this assignment takes into account only generation options using petroleum products for peaking duty, which include HFO ICRE 20 MW, LFO GT 50 MW and LFO GT 100 MW. Based on the information provided in Section 1 and the estimated cost of fuels, this section determines the unit cost of energy for peaking plants. In this case, it should be noted that peaking plants usually do not operate at annual capacity factors greater than 15 to 25%.

Table 6-2 presents the unit cost of energy in N$/kWh at various capacity factors for the selected peaking generation options. As can be seen from this table, the most economic option to meet peak demand would be a HFO ICRE 20 MW unit. At an annual capacity factor of 15%, the cost for HFO ICRE 20 MW, LFO GT 50 MW and LFO 100 MW would be N$ 4.35, N$ 4.79 and N$ 4.6 per kWh respectively. When the annual capacity factor is increased to 25%, the cost would reduce to N$ 3.18, N$ 3.97 and N$ 3.83 per kWh respectively.

Table 6-2: Unit Cost of Energy (N$/kWh) for Conventional Peaking Plants

Plant Factor (%)	HFO ICRE 20 MW	LFO GT 50 MW	LFO GT 100 MW
5.0	10.19	8.90	8.50
10.0	5.81	5.82	5.58
15.0	4.35	4.79	4.60
20.0	3.62	4.28	4.12
25.0	3.18	3.97	3.83
30.0	2.89	3.76	3.63
35.0	2.68	3.62	3.49
40.0	2.53	3.51	3.39
45.0	2.41	3.42	3.31
50.0	2.31	3.35	3.24
55.0	2.23	3.30	3.19
60.0	2.16	3.25	3.14
65.0	2.11	3.21	3.11
70.0	2.06	3.18	3.07
75.0	2.02	3.15	3.05
80.0	1.98	3.12	3.02
85.0	1.95	3.10	3.00
90.0	1.92	3.08	2.98
95.0	1.89	3.06	2.96

Note: For abbreviations, refer to List of Acronyms and Abbreviations

Figure 6-3 presents a graphic form of the results shown in Table 6-2 for the selected conventional peaking options while Figure 6-4 presents the cost in N$/kW-Year which represents the total cost for each kW for a year depending on the number of hours that a unit is operated (the greater number of hours, the higher the cost).

For this assignment, conventional HFO ICRE 20 MW would be used for the peaking duty and compared with the renewable peaking generation options.

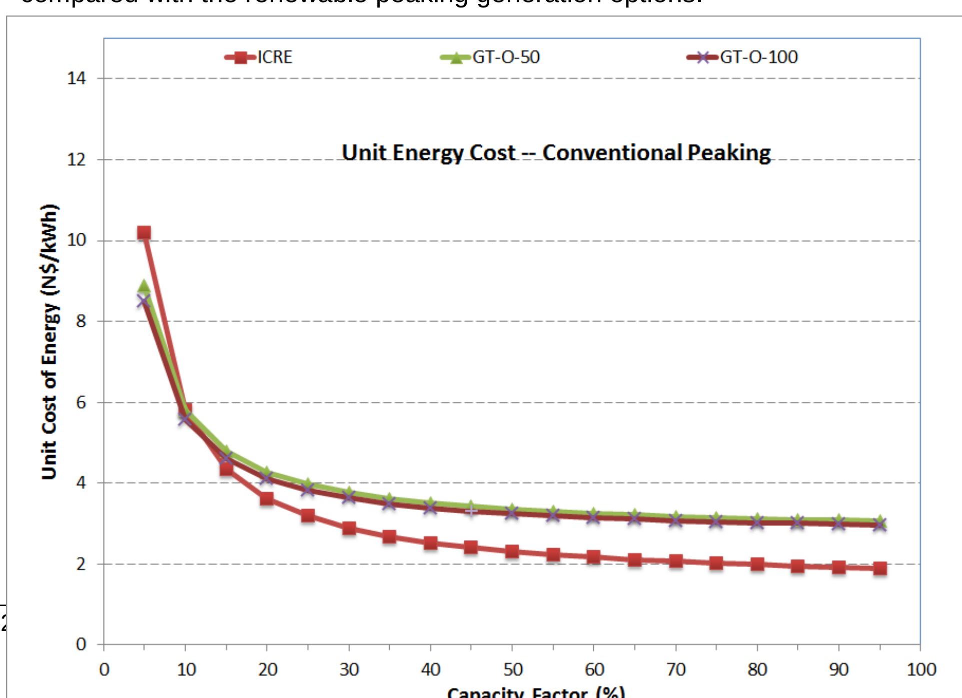

Figure 6-3: Unit Cost of Energy for Conventional Peaking Plants

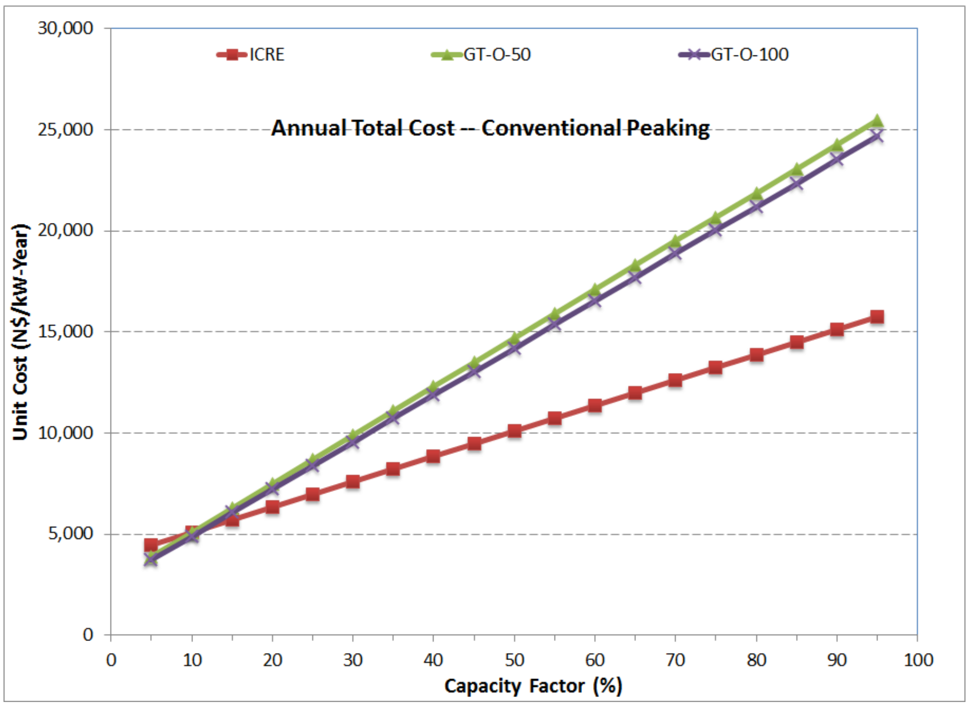

Figure 6-4: Total Annual Costs of Conventional Peaking Plants

6.2.3 Unit Cost of Energy for Dispatchable Renewable Plants

Similar to conventional generation technologies, renewable generation is divided into two categories, dispatchable and non-dispatchable (or intermittent). The dispatchable technologies are further divided into three groups, peaking, intermediate and base load. As per the information presented in Section 4, Table 6-3 presents the calculated unit cost of energy for dispatchable renewable power generation plants at various capacity factors, which include Baynes, CSP with storage, biomass and biofuel.

Table 6-3: Unit Cost of Energy (N$/kWh) for Dispatchable Renewable Plants

Plant Factor (%)	Hydro	CSP 50 MW			Biomass		Biofuel	
		Storage			BFB	BFB	CC	
	300 MW	4 Hour	8 Hour	12 Hour	5 MW	10 MW	75 MW	150 MW
5.0	20.52	19.07	27.03	35.00	19.21	17.93	10.51	9.97
10.0	10.30	9.62	13.60	17.58	10.16	9.47	6.86	6.48
15.0	6.89	6.46	9.12	11.77	7.15	6.65	5.64	5.31
20.0	5.19	4.89	6.88	8.87	5.64	5.24	5.03	4.73
25.0	4.17	3.94	5.53	7.13	4.74	4.39	4.66	4.38
30.0	3.49	3.31	4.64	5.97	4.13	3.83	4.42	4.14
35.0	3.00	2.86	4.00	5.14	3.70	3.43	4.25	3.98
40.0	2.63	2.52	3.52	4.51	3.38	3.12	4.11	3.85
45.0	2.35	2.26	3.15	4.03	3.13	2.89	4.01	3.76
50.0	2.12	2.05	2.85	3.64	2.93	2.70	3.93	3.68
55.0	1.94	1.88	2.60	3.33	2.76	2.55	3.87	3.61
60.0	1.78	1.74	2.40	3.06	2.62	2.42	3.81	3.56
65.0	1.65	1.61	2.23	2.84	2.51	2.31	3.76	3.52
70.0	1.54	1.51	2.08	2.65	2.41	2.22	3.72	3.48
75.0	1.44	1.42	1.95	2.48	2.32	2.14	3.69	3.44
80.0	1.36	1.34	1.84	2.34	2.25	2.07	3.66	3.42
85.0	1.28	1.27	1.74	2.21	2.18	2.01	3.63	3.39
90.0	1.22	1.21	1.65	2.10	2.12	1.95	3.61	3.37
95.0	1.16	1.16	1.57	1.99	2.07	1.90	3.59	3.35

Note: For abbreviations, refer to List of Acronyms and Abbreviations

It is noted that the data of Table 6-3 show the unit cost of energy for each technology for the full range of plant factors whereas the Baynes project's plant factor would be in the range of 30% and the plant factors for the CSP options would be a function of the design levels of hours of storage. Figure 6-5 presents in a graphic form the results in Table 6-3 (in N$/kWh) for selected options while Figure 6-6 presents the cost in N$/kW-Year which represents the total cost for each kW over a year depending on the number of hours that a unit is operated (the greater number of hours, the higher the cost). The notes below would be helpful to understand the results presented in Table 6-3, Figure 6-5 and Figure 6-6:

1. The average annual energy production of the proposed 600 MW Baynes hydroelectric plant has been estimated at 1,610 GWh. This means that Namibia's 50% share would be some 805 GWh per year. One could calculate that the annual capacity factor of this plant would be in the proximity of 30%. The estimated unit cost of energy is therefore approximately N$ 3.49/kWh.
2. For a CSP project with storage for four hours, it is assumed that the CSP plant will produce some power during day time and will have full output capability during daily high load demand hours. The plant would be designed and constructed with an expected annual capacity factor of 30%. At this capacity level, the unit cost of energy would be some N$ 3.31/kWh.
3. It is assumed that the CSP plant with storage of eight hours would have an annual capacity factor of 50%, which will result in a unit cost of energy of N$ 2.85/kWh.

4. It is assumed that the CSP plant with storage of 12 hours would have an annual capacity factor of 70%. In this case, the CSP plant would be operated like a base load plant and it would have a unit cost of energy of N$ 2.65/kWh.

5. It is assumed that the biomass and biofuel plants would not have energy constraints and they can produce as per system load variation requirements. At an annual capacity factor of 80%, the unit cost of energy of Biomass BFB 5 MW, Biomass BFB 10 MW, Biofuel CC 75 MW and Biofuel CC 150 MW would be some N$ 2.25/kWh, N$ 2.07/kWh, N$ 3.66/kWh and N$ 3.42/kWh.

6. Based on the calculated unit costs of energy and energy resources availability, Baynes, CSP with storage and Biomass BFB 10 MW will be taken into consideration in the next stage analysis while the other generation options listed in Table 6-3 will not be considered further.

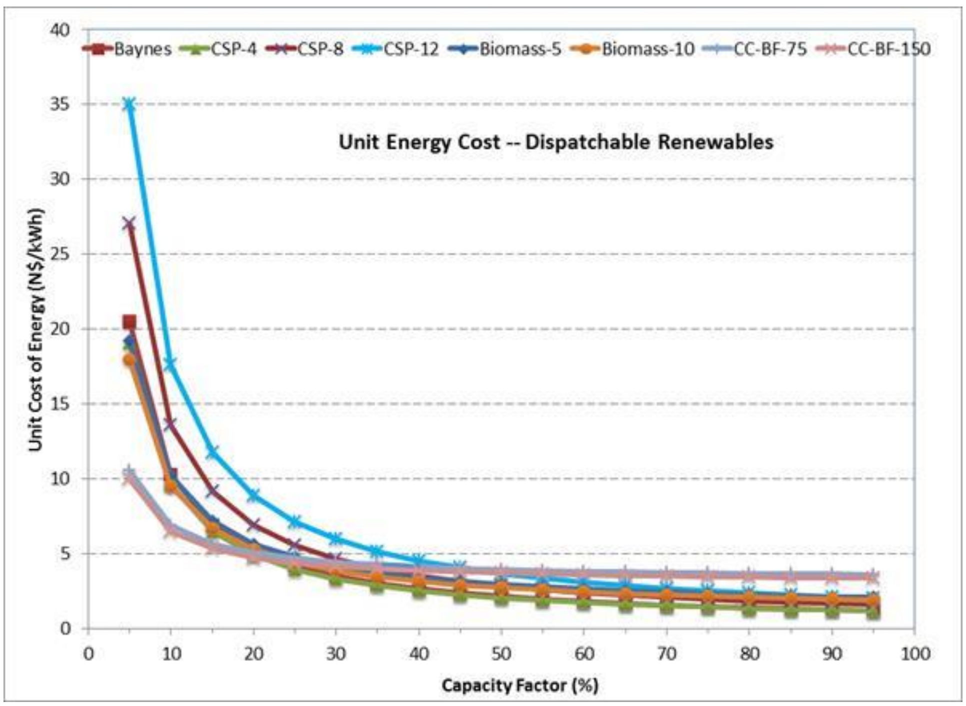

Figure 6-5: Unit Cost of Energy for Dispatchable Renewable Resources

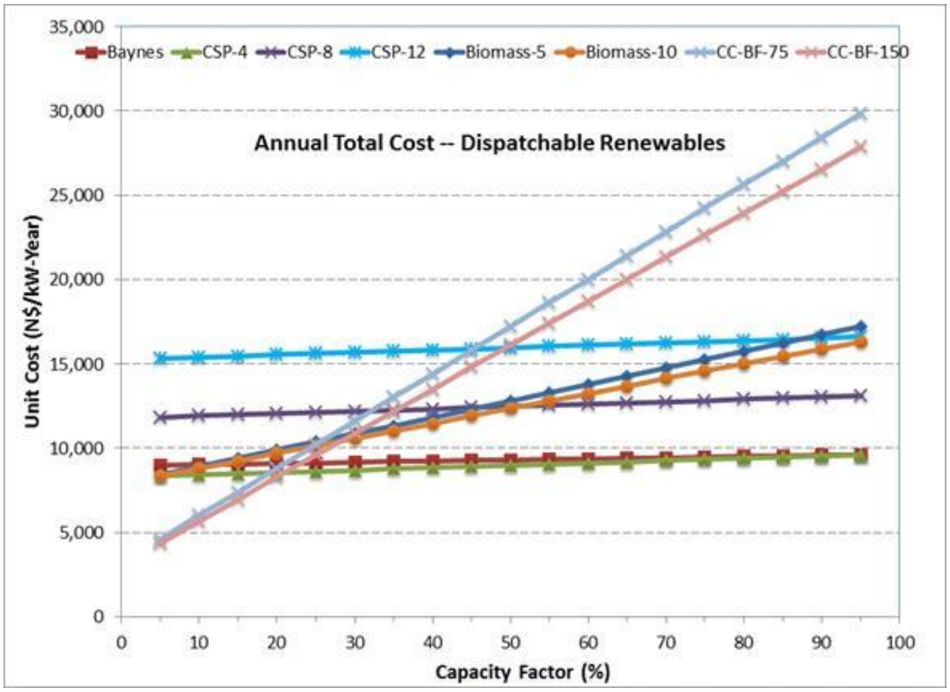

Figure 6-6: Total Annual Costs of Dispatchable Renewable Resources

6.2.4 Unit Cost of Energy for Intermittent Renewable Plants

As per the applicable technologies and available resources identified in Section 1, the intermittent renewable plants for this study will include wind, solar PV and CSP without storage. Under this assumption, these power plants will produce power when resources are available and stop production when no resources are available. The energy resource could not be stored for later use and the production of these plants is entirely dependent on the resource availability at the given time, no matter what the system load is. Table 6-4 presents the calculated costs of unit of energy for the three intermittent generation technologies.

Table 6-4: Levelised Unit Cost of Energy (N$/kWh) for Intermittent Renewable Plants

Item	Generation Technology		
	Wind	Solar PV	CSP
Capacity (MW)	50	10	50
Capacity Factor (%)	40	30	30
Unit Cost of Energy (N$/kWh)	1.54	1.61	2.57

As can be seen from Table 6-4, the unit cost of energy of wind and solar PV power is at the same magnitude while the unit cost of energy of CSP without storage is much higher. It is important to note that an assumption of 20% over build on the DC side has been made in estimating the solar PV capacity factor. It is therefore determined that CSP without storage will not be taken into account in the next stage of the analysis.

6.2.5 Unit Cost of Energy of Potential Imports

The four potential new imports from SAPP member utilities have been discussed in Section 4. Only the import from Lunsemfwa would have a unit cost of energy below N$ 2/kWh and the cost of other three are above N$2 /kWh. The import from Mozambique would be most expensive, at higher than N$ 2.6/kWh. As the Mozambique import would have a very high capacity factor and meet the base load requirement, it is determined that it will not be considered any further in the analysis.

6.2.6 Summary of Analysis

Based on the discussions and analysis provided in the previous subsections, Table 6-5 summarises the generation options retained for formulation of various generation expansion plans.

Table 6-5: Generation Options Retained

Generation Technology	Fuel	Unit/Plant Size (MW)	Resources Available (MW)	Capacity Factor (%)	Function	Unit Cost of Energy ($/kWh)
CC	NG	450	450	80	Base Load / Mid Merit	1.79
CC	LNG	150	> 300	80	Base Load	2.29
GT	LNG	50	> 200	80	Base Load	2.72
CFB	Coal	150	> 300	80	Base Load	1.54
ICRE	HFO	20	No Limit	80	Base Load	1.98
ICRE	HFO	20	No Limit	25	Peaking	3.18
Hydro	Water	300	300	30	Peaking	3.49
CSP-4 Hour	Solar	50	No Limit	30	Peaking	3.31
CSP-8 Hour	Solar	50	No Limit	50	Mid Merit	2.85
CSP-12 Hour	Solar	50	No Limit	70	Base Load	2.65
BFB	Biomass	10	<=600	80	Base Load	2.07
Wind	Wind	50	<= 300	40	Intermittent	1.54
Solar PV	Solar	10	No Limit	30	Intermittent	1.61
Import	Zambia	50	50	50	Mid Merit	2.22
Import	Lunsemfwa	50	50	80	Mid Merit	1.78
Import	Botswana	200	200	96	Base Load	2.27

6.3 Expansion Scenario Themes

This subsection describes the principal decision factors used in the formulation and development of the generation expansion scenarios studied in preparing the NIRP Update.

6.3.1 Principal Decision Factors

In generation expansion planning the principal decision factors for addition of generation units to a system include the forecast load demand, energy policy, reliability criteria, system cost and environmental and social impacts. Given a load demand forecast, the principal decision factors are the established energy policy, the reliability planning criteria and cost. In addition to other aspects, an energy policy could provide directives on the requirements for electricity production and selection of generation types, technologies and locations for generation (domestic versus imports and/or locations within the country). The energy policy may include consideration of key environmental and social impacts.

The reliability planning criteria determine when a unit should be added to the system in order to supply the forecast demand at a specified reliability level, which should be based on the established energy policy.

A national integrated resource plan should in the first instance be based on national level economic considerations rather than financial factors. However, in the selection of the preferred national level plan, it is necessary to consider the ability of the country to obtain the financing needed to develop the individual power system projects.

6.3.1.1 The White Paper on Energy Policy

The Energy Policy Committee (EPC) of the Ministry of Mines and Energy (MME) published the White Paper on Energy Policy in May 1998. Section 3 of the White Paper on Energy Policy addresses energy supply and deals with electricity, gas, liquid fuels and renewable energy. It is noted that the White Paper on Energy Policy is currently being revised by MME and its consultants with the new energy policy scheduled to be released in late 2016. Unfortunately, the NIRP Update is to be completed before this new policy is completed. In view of this, it has been agreed that the work on the NIRP Update should be based on the existing White Paper on Energy Policy of 1998.

The White Paper on Energy Policy promotes the use of renewable energy through the establishment of an adequate institutional and planning framework, the development of human resources and public awareness and suitable financing systems. The energy policy goal of sustainability is to be promoted through a requirement for environmental impact assessments and project evaluation methodologies which incorporate environmental externalities. Energy efficiency is to be promoted through policies on better information collection and dissemination, and particularly with respect to energy efficiency and conservation practices in households, buildings, transport and industry. Security of supply is to be achieved through an appropriate diversification of economically competitive and reliable sources, but with particular emphasis on Namibian resources.

6.3.1.2 Reliability Criteria

In this study, a LOLP criterion value of 5 days per year is adopted for the period from 2016 to 2020 and 2 days per year is adopted for the balance of the study horizon, which allocates adequate time to achieve the reliability goal (see Section 3.2).

6.3.1.3 Load Forecast

The load forecast used in this study is derived in Section 5. Both energy and demand are forecast. The forecasts take into account organic growth, step loads (for mining, water pumping, industrial, commercial and institutional projects including the Mass Housing Program), DSM programs and the installation of behind the meter solar PV systems.

6.3.1.4 System Cost

Scenarios are compared based on each scenario's estimated total cost over the period of the analysis. Costs include those for fuel, operating & maintenance, capital investment, unserved energy and emissions. The simulation model calculates the total cost based on the installed capacity needed to satisfy the load forecast at the set level of reliability by dispatching the fleet of power plants available in each year based on their operating costs and their ability to adjust output based on system needs,

6.3.1.5 Environmental and Social Factors

The cost of each new power plant considered in preparing alternative expansion scenarios includes allowances for the mandatory environmental and social requirements. In addition, a cost is assessed in the model to represent the indirect societal costs of emissions such as CO_2, SOx NOx and particulates based on the typical emissions level for each type of thermal plant by fuel type that is included in individual expansion scenarios.

6.3.2 Overview of Planning Factors

Previous sections have developed a number of inputs that are to be used in the planning analysis. Prior to discussing the details of the generation planning analysis, it is useful to overview some of the key inputs that will influence the results. Table 6-6 summarises several of these key inputs.

Table 6-6: Summary of Key Inputs to the Planning Analysis

A) Exisiting Generation

Plant	Maximum Output - MW 2015	2016	2017	2018
Ruacana	332	347	347	347
Van Eck	60	81	81	81
Paratus	6	6	6	0
Anixas	22	22	22	22
Solar	0	9	9	9
Total	**420**	**465**	**465**	**459**

B) Committed Generation

Project	To Be Installed -MW	Max. Ouput at System Peak - MW 2016	2017	2018
REFIT Solar/Wind	70	2	2	2
NP Solar	37	0	0	0
GreeNam Solar	20	0	0	0
Diaz Wind	44	0	15	15
Total	**171**	**2**	**17**	**17**

C) Annual System Peak - June 2, 2015 7-8 PM

Maximum load of 597 MW supplied by:

Ruacana - 253 MW, Van Eck - 29 MW, Imports - 315 MW

D) Load Growth Projections

	2015	2018	2020	2025
Peak Demand - MW	597	733	786	931
Increase from 2015 - MW		136	189	334

Section A of Table 6-6 summarises the maximum output capabilities of the existing power plants on the Namibian power system; a total of some 420 MW in 2015. The table also indicates the increase in total capability to some 465 MW scheduled for later in 2016 after the refurbishment projects at the Ruacana and Van Eck power plants are completed.

Section B of Table 6-6 lists the power plant additions that are currently committed. As indicated, a total installed capacity of 171 MW is currently committed of which some 121 MW is solar PV and some 50 MW is wind power. Due to the intermittent nature of the output from these types of power plants, and the fact that the system peak typically occurs in the evening hours, the expected output capability of these committed power plants at the time of the system peak is expected to be less than 20 MW.

In 2015 the annual system peak demand reached 597 MW and this occurred on June 2 between the hours of 7 and 8 PM. Section C of Table 6-6 indicates that the Ruacana hydro plant contributed 253 MW at the time of this system peak, the Van Eck coal –fired power plant contributed 29 MW and imports, largely from the ESKOM substation, contributed some 315 MW or slightly over 50%.

The final section of Table 6-6 indicates the projected increase in the annual system peak loads in Namibia. Section D indicates that by 2025 under the Reference (mid-range forecast) Scenario the annual peak load will have increased by some 330 MW over the 2015 level.

The overarching conclusion of this is that, unless Namibia wishes to become even more heavily dependent on imports, there is a clear need to invest in significant amounts of new fully dispatchable generation.

6.3.3 Formulation of Generation Expansion Scenarios

Reflecting the situation described in the previous section, there are a number of new power plants under consideration and/or in the negotiation stage in Namibia at this time. These include:

- Short lead time projects to meet the projected power demand and energy requirements without necessitating even greater reliance on imports
- Projects to make additional use of Namibia's abundant renewable energy resources
- Longer lead time base load generation projects

It is understood that while NamPower is actively reviewing/negotiating at least two options, no final commitment has been made as yet for a short lead time generation project. In view of this, the initial formulation of generation expansion scenarios for this report is currently based on five short-term expansion options as follows:

- Option 1 – Quick install gas turbine plant using natural gas from LNG
- Option 2 – Short-term liquid fuel based emergency generation
- Option 3 – Both quick install gas turbine plant and emergency generation
- Option 4 – No short-lead time generation
- Option 5 – No new base load generation – rely on imports

Under each of these five short-term options, a number of long-term generation expansion scenarios have been formulated and analysed. In each case other than Option 5, these include coal, LNG, domestic natural gas (Kudu), HFO and biomass/concentrated solar power scenarios. Each of these scenarios also includes renewable power plants (in addition to those included as committed projects). For this study, the penetration of intermittent renewables is considered at two levels, base and high. It is assumed that the base level includes a total of 90 MW of renewables, i.e. 40 MW of solar PV and 50 MW of wind power, while the high level includes a total of 200 MW, i.e. 100 MW of solar PV and 100 MW of wind power. In both cases these amounts are in addition to the renewables projects on the committed plants list.

Based on the information presented in Section 1, it could be summarised that the power plant size, fuel type and first possible year in service for the major generating options are as follows:

- Quick install GT, 200 MW, LNG/LFO, 2019
- Emergency ICRE generation, 100 MW, HFO/LFO, 2018 (3 year contract)
- Coal, 300 MW, 2021
- Kudu, 442 MW, 2021
- LNG, 300 MW, 2021
- ICRE 20 MW, multi unit plant, 2021
- Biomass, multiple 10 MW plants, 2021

Simulations were carried out for a number of expansion sequences under each of the five options with 30 scenarios studied in total. Table 6-7 shows the long-term capital and operating costs for each scenario. It can be seen that the total costs of these 30 scenarios over the full period of analysis (2016 – 2035) have a range of just over 20% from the lowest to the highest cost scenarios. However, for the five lowest cost scenarios, the variation from lowest cost to highest cost is under 10%. Short-term Option 2 is considered the best path forward for bridging the gap until base load plant can be installed given its relative costs and ability to quickly mitigate at least some of the short-term supply risks with a certain amount of flexibility. Although the Option 5 scenarios are shown to have lower costs, it is considered that this approach would be very risky from a supply perspective and would be diametrically opposed to the position expressed in the Energy Policy on self-supply.

Table 6-8 summarises the types of new generating plants included in each of the 11 scenarios in Option 2. Table 6-9 illustrates the year by year schedule of plant/unit additions/retirements for one of the Option 2 scenarios (Scenario 6). Similar tables for each of the 11 scenarios of Option 2 are provided in Appendix C.

In the next section, the NIRP is further developed by considering the attributes of the main generation options and how these combine to impact various national policies and financial factors. This more detailed analysis is carried out for the scenarios included in Option 2.

Table 6-7: Simulation Results for the Five Options

Alternative Description	No.	Scenario [1] Description	Main Capacity Additions from 2015 to 2035	Cost in Present Value (Million N$, 2016) From 2016 to 2035						15 Year End-Effect	Total	Rank
				Fuel	O&M	Capital	EUE	Emissions	Subtotal			
1 -- 200 MW LNG GT	1	300 MW Coal	300 MW Coal, 80 MW Biomass and 300 MW CSP	18,891	34,685	16,868	612	1,199	**72,255**	17,450	**89,705**	**11**
	2	300 MW LNG CC	300 MW LNG CC, 60 MW Biomass and 300 MW CSP	31,003	33,238	14,216	629	820	**79,905**	19,391	**99,296**	**30**
	3	442 MW Kudu NG CC [2]	442 MW NG CC, 80 MW Biomass and 350 MW CSP	22,178	33,581	18,177	624	655	**75,214**	20,732	**95,946**	**24**
	4	442 MW Kudu NG CC [3]	442 MW NG CC, 80 MW Biomass and 350 MW CSP	22,178	33,581	18,177	624	655	**75,214**	17,979	**93,192**	**17**
	5	400 MW CSP	400 MW CSP and 200 MW Biomass	21,976	35,332	19,744	971	673	**78,696**	18,930	**97,626**	**28**
	6	442 MW Kudu NG CC [3] and Baynes	442 MW NG CC, 300 MW Hydro, 60 MW Biomass and 100 MW CSP	22,714	33,112	20,146	577	669	**77,218**	18,529	**95,746**	**22**
2 -- 120 MW HFO ICRE	1	300 MW Coal	300 MW Coal, 442 MW NG CC [4], 80 MW Biomass and 250 MW CSP	15,363	33,495	18,243	853	1,205	**69,159**	16,829	**85,988**	**3**
	2	300 MW LNG CC	300 MW LNG CC [5], 442 MW NG CC [6], 80 MW Biomass and 250 MW CSP	25,020	31,952	15,572	813	816	**74,173**	17,786	**91,960**	**13**
	3	442 MW Kudu NG CC [3]	442 MW NG CC, 300 MW Coal, 80 MW Biomass and 250 MW CSP	17,855	32,715	19,586	765	938	**71,860**	16,829	**88,689**	**7**
	4	442 MW Kudu NG CC [3] and Renewable	442 MW NG CC, 400 MW CSP and 200 MW Biomass	17,972	32,611	22,849	815	571	**74,817**	18,206	**93,023**	**16**
	5	442 MW Kudu NG CC [3] and Baynes	442 MW NG CC, 300 MW Hydro, 80 MW Biomass and 300 MW CSP	17,107	32,349	26,292	740	582	**77,070**	18,739	**95,809**	**23**
	6	600 MW Coal	600 MW Coal, 80 MW Biomass and 250 MW CSP	13,427	33,904	17,924	761	1,366	**67,382**	16,279	**83,662**	**2**
	7	600 MW LNG CC	600 MW LNG CC, 80 MW Biomass and 200 MW CSP	30,578	31,691	13,226	791	849	**77,135**	19,005	**96,139**	**25**
	8	480 MW HFO ICRE	480 MW HFO ICRE, 80 MW Biomass and 250 MW CSP	22,511	32,346	15,209	664	990	**71,720**	17,317	**89,037**	**8**
	9	600 MW Coal and High Renewable [7]	600 MW Coal, 80 MW Biomass, 250 MW CSP and High Renewable	11,161	32,926	25,243	315	1,092	**70,736**	17,375	**88,111**	**6**
	10	600 MW LNG CC and High Renewable [7]	600 MW LNG CC, 80 MW Biomass, 250 MW CSP and High Renewable	22,838	31,129	21,572	294	735	**76,568**	18,903	**95,471**	**19**
	11	420 MW HFO ICRE and High Renewable [7]	420 MW HFO ICRE, 100 MW Biomass, 300 MW CSP and High Renewable	17,110	31,336	23,082	233	815	**72,577**	17,741	**90,317**	**12**
3 -- 200 MW LNG GT and 120 MW HFO HFO ICRE	1	300 MW Coal	300 MW Coal, 80 MW Biomass and 300 MW CSP	20,307	32,100	17,894	504	1,242	**72,047**	17,450	**89,497**	**10**
	2	300 MW LNG CC	300 MW LNG CC, 60 MW Biomass and 300 MW CSP	32,418	30,653	15,242	520	863	**79,697**	19,391	**99,088**	**29**
	3	442 MW Kudu NG CC [2]	442 MW NG CC, 80 MW Biomass and 350 MW CSP	23,593	30,996	19,203	515	698	**75,006**	20,732	**95,738**	**21**
	4	442 MW Kudu NG CC [3]	442 MW NG CC, 80 MW Biomass and 350 MW CSP	23,593	30,996	19,203	515	698	**75,006**	17,979	**92,985**	**15**
	5	400 MW CSP	400 MW CSP and 200 MW Biomass	23,391	32,748	20,770	863	716	**78,489**	18,930	**97,419**	**27**
	6	442 MW Kudu NG CC [3] and Baynes	442 MW NG CC, 300 MW Hydro, 60 MW Biomass and 100 MW CSP	24,129	30,527	21,172	469	712	**77,010**	18,529	**95,538**	**20**
4 -- No Quick Installation	1	300 MW Coal	300 MW Coal, 442 MW NG CC [4], 80 MW Biomass and 250 MW CSP	13,487	36,972	17,217	995	1,147	**69,818**	16,829	**86,647**	**4**
	2	300 MW LNG CC	300 MW LNG CC [5], 442 MW NG CC [6], 80 MW Biomass and 250 MW CSP	23,144	35,429	14,546	955	759	**74,833**	17,786	**92,619**	**14**
	3	442 MW Kudu NG CC [3]	442 MW NG CC, 300 MW Coal, 80 MW Biomass and 250 MW CSP	15,979	36,192	18,560	908	880	**72,519**	16,829	**89,348**	**9**
	4	442 MW Kudu NG CC [3] and Renewable	442 MW NG CC, 400 MW CSP and 200 MW Biomass	16,096	36,088	21,823	957	513	**75,477**	18,206	**93,683**	**18**
	5	442 MW Kudu NG CC [3] and Baynes	442 MW NG CC, 300 MW Hydro, 80 MW Biomass and 300 MW CSP	15,231	35,826	25,266	882	524	**77,730**	18,739	**96,469**	**26**
5 -- Full Import [8, 9]	1	Full HFO ICRE backup with 10% CF		6,776	52,143	10,261	818	508	**70,506**	16,193	**86,700**	**5**
	2	Half HFO ICRE backup with 20% CF		6,839	51,537	6,465	818	510	**66,170**	14,400	**80,570**	**1**

[1] Each scenario includes 100 MW solar PV and 100 MW wind power
[2] Kudu gas will last for 15 years
[3] Kudu gas will last for 30 years
[4] Kudu generating unit acts as mid-merit order plant and the gas will last from 2025 to 2050
[5] After commissioning of NG CC, LNG CC will be for peaking and mid-merit order load
[6] Kudu gas will last from 2025 to 2050
[7] The scenario includes 300 MW solar PV and 300 MW wind power
[8] The import energy prices are based on the current SPSA prices
[9] Fuel cost of backup MSEs is simply added to the simulation results

Table 6-8: Unit Additions by Scenario for Option 2

Generation Option	Scenario										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Base Load and Mid Merit Order											
Kudu Gas (CC)	X	X	X	X	X						
LNG (CC)		X					X			X	
Coal	X		X			X			X		
ICRE								X			X
CSP-12 Hour	X	X	X	X	X	X	X	X	X	X	X
Biomass	O	O	O	X	O	O	O	O	O	O	O
Peaking											
Baynes					O						
Intermittent											
High Wind and Solar PV	O	O	O	O	O	O	O	O	X	X	X

Legend:

X -- Main resource

O -- Support resource

Table 6-9: Unit/Plant Addition/Retirement Schedule for Scenario 6 in Option 2

Year	Project Name	Addition/Retirement								Total Capacity	Annual Peak	Reliability			
		Internal				External						Reserve		LOLP	EUE
		Individual	Cumulative	Discount (1)	Available	Individual	Cumulative	Discount (1)	Available						
		(MW)								(MW)	(MW)	(MW)	(%)	(Day/Year)	(%)
		492	492	10	482	330	330	0	330						
2016			492		482		330	0	330	812	646	167	26	0.02	0.000
2017	70 MW Solar and 20 MW Import	70	562	70	482	20	350	0	350	832	693	140	20	0.03	0.000
2018	50 MW Solar, 49 MW Wind, 120 MW HFO ICRE and Retirement of Paratus and 20 MW Import	213	775	89	606	-20	330	0	330	936	733	202	28	0.00	0.000
2019			775		606		330	0	330	936	758	177	23	0.00	0.000
2020	20 MW Solar	20	795	20	606		330	0	330	936	786	150	19	0.01	0.000
2021	300 MW Coal and Retirement of 120 MW HFO ICRE, SPSA and ZESC	180	975		786	-250	80	0	80	866	816	50	6	0.59	0.013
2022	50 MW Wind	50	1,025	40	796		80	0	80	876	842	34	4	1.13	0.025
2023			1,025		796		80	0	80	876	869	7	1	1.79	0.038
2024	20 MW Solar and 20 MW Biomass	40	1,065	20	816		80	0	80	896	899	-3	0	1.80	0.038
2025	300 MW Coal and Retirement of Van Eck and ZESA	192	1,257		1008	-80	0	0	0	1008	931	77	8	0.63	0.013
2026	20 MW Solar	20	1,277	20	1008		0	0	0	1008	964	44	5	1.91	0.041
2027	50 MW CSP	50	1,327		1058		0	0	0	1058	1,001	57	6	1.31	0.027
2028	50 MW Wind and 20 MW Biomass	70	1,397	40	1088		0	0	0	1088	1,039	49	5	1.22	0.024
2029	50 MW CSP	50	1,447		1138		0	0	0	1138	1,078	60	6	0.85	0.017
2030	20 MW Solar	20	1,467	20	1138		0	0	0	1138	1,119	19	2	1.44	0.027
2031	20 MW Biomass	20	1,487		1158		0	0	0	1158	1,159	-1	0	1.91	0.035
2032	20 MW Solar and 50 MW CSP	70	1,557	20	1208		0	0	0	1208	1,195	12	1	1.22	0.021
2033	20 MW Biomass	20	1,577		1228		0	0	0	1228	1,239	-12	-1	1.76	0.030
2034	50 MW CSP	50	1,627		1278		0	0	0	1278	1,281	-3	0	1.39	0.023
2035	50 MW CSP	50	1,677		1328		0	0	0	1328	1,329	-1	0	1.24	0.020

Note: The capacity reduced in calculation of the expected generation capacity at the time of system peak. It is assumed that solar PV will have no contribution to system peak while wind power contributes 20% of its installed capacity

7. Selection of Preferred Scenarios

7.1 Introduction

In addition to lowest direct cost, there are a number of criteria of national importance that need to be considered in selecting the projects to include in the NIRP implementation plan. After introducing these criteria and showing how each individual generation option ranks on these factors, the scenarios of Option 2 are assessed against these criteria. This leads to the selection of several policy scenarios. The sensitivity of these to changes in base case parameters is then checked.

7.2 Assessment of the Generation Option on the Criteria

Several criteria have been defined to rate the main generation options on how they meet existing or potential national energy policies and how they compare on financial considerations. These are described below. Table 7-1 summarises how each generating technology ranks on these factors.

7.2.1 Generation in Namibia

The White Paper on Energy Policy establishes the amounts of generation to be from internal sources. It states that "Duly considering associated risks, it is the aim of government that 100% of the peak demand and at least 75% of the electric energy demand would be supplied from internal sources by 2010. Risk mitigation measures would be pursued, including the possibility of regional equity participation in, and guarantees for, Namibian generation projects."

The goals mentioned in the foregoing paragraph have not been achieved to date. Generation resources located within Namibia can currently supply up to approximately 420 MW (this will increase to some 465 MW when the refurbishment projects at Ruacana and Van Eck are fully completed in 2016). In comparison, a peak demand of 597 MW occurred in June 2015. According to NamPower's annual report, imports from sources outside Namibia have accounted for approximately 65% of the energy requirement in the last two years (including supply to the Skorpion Zinc Mine).

Taking into account the current power supply conditions in Namibia and the lead time required for the addition of new generation units/plants, it is expected that the internal resource requirements outlined in the White Paper on Energy Policy could be achieved within the next five years, i.e. by approximately 2021. Each power plant built in Namibia would contribute to meeting this policy.

7.2.2 Use of Indigenous Resources

It is naturally considered to be desirable to make appropriate use of indigenous energy resources in supplying the electricity demand in Namibia. As indicated in Table 7-1, many of the power plant options under consideration would do so. This includes the Kudu Project that would use offshore natural gas and the Baynes hydroelectric plant that would use water shared with Angola.

Table 7-1: Attributes of Generation Options

Generation Technology	Energy Source	Located in Namibia	Use of Indigenous Resources	Renewable Energy	Foreign Exchange Requirement	Need for Government Investment	Development/ Operating Complexity
Combined Cycle	Kudu NG	yes	yes	no	inv + ops	high	high
Combined Cycle	LNG	yes	no	no	inv + ops	moderate	medium
Gas Turbine	LNG	yes	no	no	inv + ops	moderate	medium
Steam Turbine	Coal	yes	no	no	inv + ops	moderate	low
ICRE	HFO	yes	no	no	inv + ops	limited	low
Hydro	Baynes water	yes	yes	yes	inv only	high	high
CSP	sunlight	yes	yes	yes	inv only	moderate	medium
Steam Turbine	Biomass	yes	yes	yes	inv only	limited	medium
Wind	wind	yes	yes	yes	inv only	no	low
Solar PV	sunlight	yes	yes	yes	inv only	no	low
Import	coal/NG	no	no	no	ops	no	low
Import	water	no	no	yes	ops	no	low

(shaded) indicates a relatively desirable rating

7.2.3 Renewable Energy

Like many other countries, Namibia aspires to use more renewable energy to achieve reductions in its GHG emissions as well as to avail the country of the numerous other benefits associated with the use of renewable energy. Namibia's submission to the recent COP 21 meetings in Paris, France titled "Intended Nationally Determined Contributions" (INDC) showed that the energy sector is expected to contribute to the national level INDC by increasing the share of renewables in electricity production from 33% in 2010 to 70% by 2030. While this objective is conditional on Namibia receiving some US$ 33 billion in foreign financial support, it is indicative of the importance of increased consideration of renewable energy in the country's energy mix. Table 7-1 indicates that a significant number of the generation options under consideration would be based on renewable energy.

7.2.4 *Foreign Exchange Requirement*

As a rapidly developing country with an ambitious development plan (Namibia Vision 2030) underway, Namibia has many competing uses for its available foreign exchange capability. There are significant differences in the amount of foreign exchange that would be required to invest in and operate the various power generation options. As indicated in Table 7-1, a number of the options would require overseas sourcing of the generation equipment as well as ongoing fuel purchases. Even in the case of the Kudu project, it is expected that the natural gas supply would involve an ongoing foreign exchange requirement as the developer (assuming this to be a foreign investor) would need to be covered for the foreign exchange component of the investment required to develop and operate the gas field and the undersea pipeline. In the case of the Baynes project, a material share of the capital cost would be for civil works which would largely be carried out in N$. For imports there would not be an upfront foreign exchange requirement but the power price would generally be expected to be denominated in US$.

7.2.5 *Need for Government Investment*

This is one of the more difficult attributes to assess at this planning stage as it is not known how an individual generating option would be procured. Some projects naturally lend themselves to a high level of government financing whereas other projects could be undertaken by the private sector if the enabling conditions are in place. The following discussion elaborates on some of the factors involved.

Kudu natural gas – this project involves development of an offshore natural gas reserve in deep water, far offshore. Since the discovery of this gas field a number of private sector investors have been involved but to date the investment needed to develop the project has not materialised. It is likely that the Government of Namibia would need to make a significant investment to reduce the risk to private sector investors. Once the natural gas is brought to shore it would be used in a conventional power plant but given the size of the power plant needed to make the natural gas delivery system economic there is both a risk that power surplus to Namibian needs could not be sold at a price that covers costs and that the generating unit size (442 MW) being large relative to the Namibian power sector could lead to reliability issues. Both of these factors point to additional need for government investment. In addition, NamPower would need to invest in the high voltage transmission infrastructure needed to deliver the power to the main NamPower grid.

Conventional generation – combined cycle, gas turbine and coal-fired power stations in the 300 MW range are developed by the private sector in many countries. However, given the size of the Namibian power sector and the limited involvement of IPPs in the sector to date, even in small generation projects, it is likely that these plants would require a certain amount of government investment. This is a subject that will no doubt be addressed by the “Review and Update of Namibia’s IPP and Investment Market Framework” that is now underway. It is likely that Government investment would also be needed for the infrastructure required to deliver the fuel to the power plant, particularly for projects that would be based on imported natural gas for which port, re-gasification and pipeline investment would be needed. For these types of generating options it is expected that “moderate” government investment would be required.

Internal combustion reciprocating engines – this type of project typically involves multiple relatively small engines and has relatively low investment and operating risk and could potentially be developed with limited or no government investment dependent on the terms of the PPA that is offered.

Baynes hydroelectric project – the return on investment on a hydroelectric project is typically spread over the long-term operating life of these plants and hence it is unusual for these to be developed by IPPs. Given the complications of the Baynes project regarding shared water use with Angola and relatively low annual capacity factor, it is expected that this project would need to be financed entirely, either directly or indirectly, by the Government.

Concentrated solar power – this technology is relatively new and long-term profitable operation of sizeable plants has not been demonstrated, even in the larger market in Republic of South Africa. It is expected that at least the initial plants would need to be financed largely by the Government of Namibia. Hence this technology is categorised as requiring “moderate” government investment in Table 7-1.

Biomass (encroacher bush) – small sized biomass plants using encroacher bush are considered to represent a very good opportunity for private investment. However, it is considered that a commercial scale pilot project owned by the government would be needed to demonstrate the operating and economic characteristics of these projects before that private sector investment would be forthcoming. This technology is therefore shown as needing “limited” government investment.

Wind and solar PV – power plants using these technologies are routinely developed entirely with private investment. But for this to happen, bankable PPAs with reasonable prices and limited ability of the buyer to dispatch off are required.

Imports – typically no direct government investment is required. However, in some cases transmission investment could be needed.

7.2.6 Development/Operating Complexity

The ranking on this attribute varies significantly amongst the generating alternatives as shown in Table 7-1. The Kudu Natural Gas project is shown as “high” due to the offshore location, delivery distance, export requirements and generating unit size. These factors give it a “high” rating. Projects involving LNG are shown as “medium” due to the requirements for delivery and conversion of LNG to usable natural gas. Baynes hydroelectric plant is shown as “high” due to the shared water usage. CSP and biomass based on encroacher bush are both shown as “medium” at this time but once initial plants have been developed and operated successfully this rating could be moved to the low range. The other generating technologies are all ranked “low” on this factor.

7.3 Selection of Top Ranked Scenarios

In Section 6.3.3 the short-term Option 2 scenarios were selected as the most promising. The total costs of these scenarios are summarised as below. It is noted that the cost of transmission to connect generation to the grid is included in the cost estimates.

Scenario	Capsule Description		Total Cost*
1	Coal	followed by Kudu, Biomass, CSP	85,988

2	LNG	followed by Kudu, Biomass, CSP	91,960
3	Kudu	followed by coal, biomass and CSP	88,689
4	Kudu	followed by biomass and CSP	93,023
5	Kudu	followed by Baynes, biomass and CSP	95,809
6	Coal	followed by Biomass and CSP	83,662
7	LNG	followed by Biomass and CSP	96,139
8	ICRE	followed by Biomass and CSP	89,037
9	Ren1	Coal and High Renewables	88,111
10	Ren2	LNG and High Renewables	95,471
11	Ren 3	ICRE and High Renewables	90,317

* Present value in 2016 of all costs for the period 2016-2050 expressed in millions of N$

The next step in the analysis is to demonstrate the overall position of these scenarios on the criteria described in the previous section. This is shown in Table 7-2 and is discussed in the paragraphs that follow the table.

Table 7-2: Criteria of Generation Expansion Alternatives

Scenario Description	Main Capacity Additions	2030 Namibia (%)	Renewable (%)	Indigenous (%)	CO2 (MT)	Capital [1] (Million N$)
300 MW Coal	300 MW Coal, 442 MW NG CC, 80 MW Biomass and 250 MW CSP	99.35	51.81	67.89	2.677	31,403
300 MW LNG CC	300 MW LNG CC, 442 MW NG CC, 80 MW Biomass and 250 MW CSP	99.29	49.48	91.72	1.255	25,819
442 MW Kudu NG CC	442 MW NG CC, 300 MW Coal, 80 MW Biomass and 250 MW CSP	99.34	51.63	67.76	2.687	34,083
442 MW Kudu NG CC and Renewable	442 MW NG CC, 400 MW CSP and 200 MW Biomass	99.23	79.42	98.77	0.490	40,754
442 MW Kudu NG CC and Baynes	442 MW NG CC, 300 MW Hydro, 80 MW Biomass and 300 MW CSP	99.11	74.85	98.49	0.598	50,105
600 MW Coal	600 MW Coal, 80 MW Biomass and 250 MW CSP	99.33	49.48	49.48	3.616	30,862
600 MW LNG CC	600 MW LNG CC, 80 MW Biomass and 200 MW CSP	98.99	44.75	44.75	1.456	21,183
480 MW HFO ICRE	480 MW HFO ICRE, 80 MW Biomass and 250 MW CSP	98.63	51.81	51.81	2.027	25,501
600 MW Coal and High Renewable	600 MW Coal, 80 MW Biomass, 250 MW CSP and High Renewable	99.97	71.05	71.05	2.112	40,157
600 MW LNG CC and High Renewable	600 MW LNG CC, 80 MW Biomass, 250 MW CSP and High Renewable	99.98	71.05	71.05	0.778	32,666
420 MW HFO ICRE and High Renewable	420 MW HFO ICRE, 100 MW Biomass, 300 MW CSP and High Renewable	100.00	73.20	73.20	1.171	36,069

Scenario Description	Main Capacity Additions	3035 Namibia (%)	Renewable (%)	Indigenous (%)	CO2 (MT)	Capital [1] (Million N$)
300 MW Coal	300 MW Coal, 442 MW NG CC, 80 MW Biomass and 250 MW CSP	99.41	58.28	72.67	2.723	61,022
300 MW LNG CC	300 MW LNG CC, 442 MW NG CC, 80 MW Biomass and 250 MW CSP	99.45	58.28	93.66	1.232	52,708
442 MW Kudu NG CC	442 MW NG CC, 300 MW Coal, 80 MW Biomass and 250 MW CSP	99.41	58.28	72.67	2.723	63,703
442 MW Kudu NG CC and Renewable	442 MW NG CC, 400 MW CSP and 200 MW Biomass	99.31	81.52	98.89	0.523	76,712
442 MW Kudu NG CC and Baynes	442 MW NG CC, 300 MW Hydro, 80 MW Biomass and 300 MW CSP	98.89	71.89	97.91	0.789	88,329
600 MW Coal	600 MW Coal, 80 MW Biomass and 250 MW CSP	99.53	58.28	58.28	3.557	59,903
600 MW LNG CC	600 MW LNG CC, 80 MW Biomass and 200 MW CSP	99.20	54.15	54.15	1.436	43,354
480 MW HFO ICRE	480 MW HFO ICRE, 80 MW Biomass and 250 MW CSP	99.11	58.28	58.28	2.105	50,326
600 MW Coal and High Renewable	600 MW Coal, 80 MW Biomass, 250 MW CSP and High Renewable	99.93	71.69	71.69	2.448	75,933
600 MW LNG CC and High Renewable	600 MW LNG CC, 80 MW Biomass, 250 MW CSP and High Renewable	99.95	71.69	71.69	0.903	63,761
420 MW HFO ICRE and High Renewable	420 MW HFO ICRE, 100 MW Biomass, 300 MW CSP and High Renewable	100.00	77.63	77.63	1.161	68,378

Note: (1) Cumulative capital charge from 2016 to the indicated year

- White Paper on Energy Policy – Within the period 2021-2025, each of the scenarios would be able to supply 100% of the peak load and more than 75% of the annual energy generation from domestic power plants. As shown in Table 7-2, each of these scenarios would have close to 100% of annual kWh generation in Namibia in 2030 and onwards. It is noted that the targets for self-sufficiency may be revised as an outcome of the review and update of the White Paper on Energy Policy that is currently underway.

- Use of Indigenous Resources - As shown in Table 7-2, both Scenarios 4 and 5 would use very close to 100% indigenous energy resources. Even though Scenario 2 includes imported LNG, this plant would not be dispatched as base load after the Kudu project is on-line and hence by 2030 this scenario would also use largely indigenous energy resources. The scenarios relying on imported coal, LNG and HFO for base load generation (Scenarios 6, 7 and 8) would use approximately 50% indigenous energy resources. For those same scenarios combined with high renewable capacity (Scenarios 9, 10 and 11) the use of indigenous energy resources would increase to the 70-75% level.

- Renewable Energy – Table 7-3 compares the types and amounts of renewables based energy generation included in selected scenarios (Scenarios 1, 2 and 3 have relatively low levels of renewable and are not included in this table; it is also noted that negative signs in this table represent retirements). Scenarios 4 and 5 are heavily based on renewable generation and these would have 75-80% of annual kWh generation based on renewable energy thus meeting the target of at least 70% renewable based generation given in the INDC document. It is noted that achievement of this level assumes installation of multiple CSP plants and encroacher bush based biomass plants and these technologies have not yet been demonstrated to be economically attractive for Namibia. Scenarios 9, 10 and 11 would also have over 70% of annual kWh generation from renewables. In these scenarios large amounts of solar PV and wind generation enable this. However, both of these technologies offer only intermittent production and this level of non-dispatchable generation on the Namibian system would almost certainly result in serious operational issues. It is understood that both NamPower and the ECB are planning renewable integration studies.
- Foreign Exchange Requirement – most of the equipment required for the various generating plants would be imported. Scenarios 9, 10 and 11 with extra generation to achieve higher levels of renewable based generation while providing for generation to operate when the wind is not blowing and in hours of darkness would tend to have higher initial foreign exchange requirements. Once the initial investment is made, the annual foreign exchange requirements of the scenarios with higher levels of renewables would be lower. For the Kudu natural gas project, the foreign exchange component of the Kudu natural gas price would determine the total amounts of foreign exchange required. Similarly, for those scenarios that include coal, if this fuel could be imported from Republic of South Africa priced in Rand this would reduce the foreign exchange component significantly.
- Need for Government Investment – The total capital charges (related to both government and private investment) in the periods to 2030 and 2035 for Scenarios 6, 7 and 8 would generally be lower than those for other scenarios. For example the average total capital charges for those three scenarios up to 2035 would be N$ 51,000 million whereas for the other scenarios the average would be N$ 69,000 million or almost 40% higher. Scenarios 1-5 including Kudu, and in the case of Scenario 5 also including Baynes, would be expected to have the highest requirements for investment by the Government of Namibia.
- Greenhouse Gas Emissions – As indicated in Table 7-2, Scenarios 1, 3, 6 and 9 that include a coal-fired plant would have significantly higher greenhouse gas emissions than would the other scenarios.

- Development/Operating Complexity – based on the information provided in Table 7-1, the level of development/operating complexity would be higher for those scenarios including Kudu, particularly those in which Kudu would be the first base load plant (Scenarios 3, 4 and 5), and particularly for Scenario 5 which also includes Baynes. While Table 7-1 indicates that complexity for wind and solar PV is considered to be low on an individual unit basis, when there are very high levels of intermittent renewables on a system the complexity of operating the system can increase significantly. It is expected that this would be the case under Scenarios 9, 10 and 11,
- Conclusions – While no scenario scores high across all of the aspects that have been assessed, it is considered that Scenarios 6, 7 and 8 demonstrate a good balance across the range of criteria reviewed.

Table 7-3: Level of Renewables Integration for Selected Scenarios

Year	All scenarios shown are for Alternative 2 (short-term liquid fuel based emergency generation for the period from 2018 to 2020)															
	4		5		6		7		8		9		10		11	
	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)	Type	Capacity (MW)
2016																
2017																
2018	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3	ICRE	-6.3
2019											Solar PV	20	Solar PV	20	Solar PV	20
2020	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	40	Solar PV	40	Solar PV	40
2021	Kudu Gas	442	Kudu Gas	442	Coal	300	LNG	300	ICRE	260	Wind	100	Wind	100	Wind	100
	CSP	50	CSP	50							Coal	300	LNG CC	300	ICRE	260
2022	Wind	50	Wind	50	Wind	50	Wind	50	Wind	50	Solar PV	40	Solar PV	40	Solar PV	40
															Biomass	20
2023	Biomass	20	Biomass	20					Biomass	20	Wind	100	Wind	100	Wind	100
															ICRE	40
2024	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	40	Solar PV	40	Solar PV	40
	Biomass	20	Biomass	20	Biomass	20	Biomass	20	CSP	50	Biomass	20	Biomass	20	ICRE	40
2025	Coal	-108	Coal	-108	Coal	-108	Coal	-108	Coal	-108	Coal	-108	Coal	-108	Coal	-108
	Biomass	80	Biomass	40	Coal	300	LNG	300	ICRE	180	Wind	100	Wind	100	Wind	100
	CSP	100	CSP	150							Coal	300	LNG CC	300	CSP	100
															Biomass	20
2026	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	40	Solar PV	40	Solar PV	40
	CSP	50	Hydro	300					Biomass	20					ICRE	40
2027	Biomass	20			CSP	50			CSP	50	Solar PV	40	Solar PV	40	Solar PV	40
											CSP	50	CSP	50	Biomass	20
2028	Wind	50	Wind	50	Wind	50	Wind	50	Wind	50	Solar PV	40	Solar PV	40	Solar PV	40
	Biomass	20			Biomass	20	CSP	50			Biomass	20	Biomass	20	ICRE	40
2029	CSP	50			CSP	50			ICRE	20	Solar PV	40	Solar PV	40	Solar PV	40
											CSP	50	CSP	50	CSP	50
2030	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	CSP	50	CSP	50		
	Biomass	20					Biomass	20	Biomass	20						
2031	Biomass	20			Biomass	20	CSP	50	CSP	50	Biomass	20	Biomass	20	CSP	50
2032	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	Solar PV	20	CSP	50	CSP	50	Biomass	20
	CSP	50			CSP	50	Biomass	20	ICRE	20						
2033	CSP	50			Biomass	20	CSP	50	CSP	50	Biomass	20	Biomass	20	CSP	50
									Biomass	20						
2034			CSP	50	CSP	50	Biomass	20							Biomass	20
2035	CSP	50	CSP	50	CSP	50	CSP	50	CSP	50	CSP	50	CSP	50	CSP	50
By 2030																
Total (MW)		1673.5		1823.5		1541.5		1491.5		1421.5		2011.5		2011.5		1851.5
Renewable (MW)		**1210.0**		**1360.0**		**920.0**		**870.0**		**940.0**		**1390**		**1390**		**1410.0**
Hydro		346.5		646.5		346.5		346.5		346.5		346.5		346.5		346.5
Solar PV		284.5		284.5		284.5		284.5		284.5		504.5		504.5		504.5
Wind		149.0		149.0		149.0		149.0		149.0		349.0		349.0		349.0
Biomass		180.0		80.0		40.0		40.0		60.0		40.0		40.0		60.0
CSP		250.0		200.0		100.0		50.0		100.0		150.0		150.0		150.0
Capacity (%)		72.3		74.6		59.7		58.3		66.1		69.1		69.1		76.2
Energy (%)		79.42		74.85		49.48		44.75		51.81		71.05		71.05		73.2
By 2035																
Total (MW)		1888.5		1968.5		1776.5		1726.5		1656.5		2176.5		2176.5		2066.5
Renewable (MW)		**1425.0**		**1505.0**		**1155.0**		**1105.0**		**1155.0**		**1555.0**		**1555.0**		**1625.0**
Hydro		346.5		646.5		346.5		346.5		346.5		346.5		346.5		346.5
Solar PV		329.5		329.5		329.5		329.5		329.5		529.5		529.5		529.5
Wind		149.0		149.0		149.0		149.0		149.0		349.0		349.0		349.0
Biomass		200.0		80.0		80.0		80.0		80.0		80.0		80.0		100.0
CSP		400.0		300.0		250.0		200.0		250.0		250.0		250.0		300.0
Capacity (%)		75.5		76.5		65.0		64.0		69.7		71.4		71.4		78.6
Energy (%)		81.52		71.89		58.28		54.5		58.28		71.69		71.69		77.63

7.4 Sensitivity Studies

Sensitivity studies were carried out to test the impacts of changes to the following base case parameters:

- Capital cost.
- Fuel price.
- Discount rate.
- Low and high load forecasts.
- Cost assessed against CO_2 emissions.

The results of this analysis are discussed in separate subsections for each parameter and numerical results are provided in accompanying tables. All the numbers in these tables represent the present value total cost of the indicated scenario over the period 2016 to 2050 expressed in millions of N$ 2016.

7.4.1 Capital Cost

Table 7-4 presents the sensitivity study results on power plant capital cost. This table is set up to indicate the impacts of capital cost changes on total scenario costs and can also be used to compare the impacts of assumptions on the cost of one technology changing while a competing one does not change. For instance, it shows that if the capital cost of a coal-fired power plant increases by 20% (Scenario 6) and the cost of ICRE based power stations does not change (Scenario 8) the coal based scenario would remain less expensive over the period of analysis. This would also be the case if the cost of the ICRE based power station declined by 20%. The table also shows how much the total cost of each scenario would change per N$ 100 per kW change in the assumed capital cost and this information can be used to calculate crossover values.

This table indicates that the results are not very sensitive to differential capital cost changes in the 20% range.

Table 7-4: Sensitivity Results – Power Plant Capital Costs

Parameter	Variation	Scenario										
		1	2	3	4	5	6	7	8	9	10	11
		300 MW Coal	300 MW LNG CC	442 MW Kudu NG CC	442 MW Kudu NG CC and Renewable	442 MW Kudu NG CC and Baynes	600 MW Coal	600 MW LNG CC	480 MW ICRE	600 MW Coal & High Renewbales	600 MW LNG CC & High Renewbales	420 MW ICRE & High Renewbales
Baase Case		**85,987.7**	**91,959.6**	**88,688.9**	**93,023.3**	**95,809.1**	**83,661.6**	**96,139.4**	**89,037.1**	**88,111.5**	**95,471.1**	**90,317.5**
Coal Plant	By -20%	84,345.8		87,599.1			80930			85379.9		
	Increase (Decrease)	-1,641.9		-1,089.8			-2,731.6			-2,731.6		
	By +20%	87,629.5		89,778.6			86393.1			90843.1		
	Increase (Decrease)	1,641.8		1,089.7			2,731.5			2,731.6		
	For Every N$ 100/kW	**19.5**		**13.0**			**32.5**			**32.5**		
Kudu Gas Plant	By -20%	85,034.4	91,006.4	87,252.7	91,587.1	94,373.0						
	Increase (Decrease)	-953.3	-953.2	-1,436.2	-1,436.2	-1,436.1						
	By +20%	86,940.9	92,912.8	90,125.0	94,459.4	97,245.3						
	Increase (Decrease)	953.2	953.2	1,436.1	1,436.1	1,436.2						
	For Every N$ 100/kW	**19.8**	**19.8**	**29.9**	**29.9**	**29.9**						
LNG CC Plant	By -20%		90,892.6					94,364.2			93,695.9	
	Increase (Decrease)		-1,067.0					-1,775.2			-1,775.2	
	By +20%		93,026.6					97,914.6			97,246.2	
	Increase (Decrease)		1,067.0					1,775.2			1,775.1	
	For Every N$ 100/kW		**22.1**					**36.8**			**36.8**	
Baynes Plant	By -20%					93,960.8						
	Increase (Decrease)					-1,848.3						
	By +20%					97,657.5						
	Increase (Decrease)					1,848.4						
	For Every N$ 100/kW					**11.1**						
ICRE Plant	By -20%								87,435.6			88,833.8
	Increase (Decrease)								-1,601.5			-1,483.7
	By +20%								90,638.7			91,801.1
	Increase (Decrease)								1,601.6			1,483.6
	For Every N$ 100/kW								**26.7**			**24.7**

7.4.2 *Fuel Cost*

The sensitivity study results on fuel cost are shown in Table 7-5. As with Table 7-4, this table is designed to provide the information needed to assess virtually any set of assumptions on fuel price changes. For each scenario, the impacts of changes in the price of each type of fuel used in that scenario are shown. This information can be used to assess the impacts across scenarios of price increases for certain fuels but not others. Again, it can be seen that the base case rankings are quite robust to differential fuel price changes in the 20% range.

Table 7-5: Sensitivity Study Results – Fuel Cost

Parameter	Variation	Scenario										
		1	2	3	4	5	6	7	8	9	10	11
		300 MW Coal	300 MW LNG CC	442 MW Kudu NG CC	442 MW Kudu NG CC and Renewable	442 MW Kudu NG CC and Baynes	600 MW Coal	600 MW LNG CC	480 MW ICRE	600 MW Coal & High Renewbales	600 MW LNG CC & High Renewbales	420 MW ICRE & High Renewbales
Base Case		**85,987.7**	**91,959.6**	**88,688.9**	**93,023.3**	**95,809.1**	**83,661.6**	**96,139.4**	**89,037.1**	**88,111.5**	**95,471.1**	**90,317.5**
Coal Price	By -20%	84,156.6	91,317.5	87,400.3	92,575.6	95,361.5	81,349.2	95,497.3	88,395.0	86,321.5	94,829.0	89,675.4
	Increase (Decrease)	-1,831.1	-642.1	-1,288.6	-447.7	-447.6	-2,312.4	-642.1	-642.1	-1,790.0	-642.1	-642.1
	By +20%	87,818.7	92,601.7	89,977.4	93,470.9	96,256.8	85,973.9	96,781.5	89,679.2	89,901.5	96,113.1	90,959.6
	Increase (Decrease)	1,831.0	642.1	1,288.5	447.6	447.7	2,312.3	642.1	642.1	1,790.0	642.0	642.1
	For Every N$ 100/Tonne	**817.4**	**286.7**	**575.2**	**199.8**	**199.8**	**1,032.3**	**286.6**	**286.6**	**799.1**	**286.6**	**286.7**
Kudu Gas Price	By -20%	84,940.7	89,243.0	86,623.5	90,636.0	93,116.8						
	Increase (Decrease)	-1,047.0	-2,716.6	-2,065.4	-2,387.3	-2,692.3						
	By +20%	87,034.6	94,676.1	90,754.2	95,410.5	98,501.5						
	Increase (Decrease)	1,046.9	2,716.5	2,065.3	2,387.2	2,692.4						
	For Every N$ 10/GJ	**327.2**	**848.9**	**645.4**	**746.0**	**841.4**						
LNG Price	By -20%		90,074.8					89,947.1			91,331.1	
	Increase (Decrease)		-1,884.8					-6,192.3			-4,140.0	
	By +20%		93,844.4					102,331.7			99,611.1	
	Increase (Decrease)		1,884.8					6,192.3			4,140.0	
	For Every N$ 10/GJ		**436.3**					**1,433.4**			**958.3**	
Biomass Price	By -20%	85,698.3	91,699.0	88,344.9	92,148.9	95,389.1	83,391.1	95,892.7	88,732.2	87,841.0	95,200.6	89,927.2
	Increase (Decrease)	-289.4	-260.6	-344.0	-874.4	-420.0	-270.5	-246.7	-304.9	-270.5	-270.5	-390.3
	By +20%	86,277.1	92,220.1	89,032.8	93,897.7	96,229.2	83,932.1	96,386.1	89,342.0	88,382.0	95,741.6	90,707.8
	Increase (Decrease)	289.4	260.5	343.9	874.4	420.1	270.5	246.7	304.9	270.5	270.5	390.3
	For Every N$ 100/Tonne	**170.3**	**153.2**	**202.3**	**514.4**	**247.1**	**159.1**	**145.1**	**179.3**	**159.1**	**159.1**	**229.6**
HFO Price	By -20%	85,397.0	91,373.3	88,130.1	92,464.9	95,244.4	83,057.6	95,537.8	84,395.7	87,562.6	94,924.4	87,250.5
	Increase (Decrease)	-590.7	-586.3	-558.8	-558.4	-564.7	-604.0	-601.6	-4,641.4	-548.9	-546.7	-3,067.0
	By +20%	86,578.3	92,545.9	89,247.6	93,581.7	96,373.9	84,265.6	96,741.1	93,678.5	88,660.3	96,017.7	93,384.4
	Increase (Decrease)	590.6	586.3	558.7	558.4	564.8	604.0	601.7	4,641.4	548.8	546.6	3,066.9
	For Every N$ 10/GJ	**219.2**	**217.6**	**207.4**	**207.3**	**209.6**	**224.2**	**223.3**	**1,722.6**	**203.7**	**202.9**	**1,138.3**

7.4.3 *Discount Rate*

Table 7-6 shows the sensitivity study results on discount rate for selected scenarios (Scenarios 1, 3, 5 and 6).

From the results presented in Table 7-6, one could understand that the increase/decrease in total system cost is not a linear function of discount rate. It could also be concluded that even the significant variations in the discount rate assessed in Table 7-6 would not change the rankings of the four scenarios.

Table 7-6: Sensitivity Study Results – Discount Rate

Parameter/Variation	Scenario			
	1	3	5	6
Base Case	**85,987.7**	**88,688.9**	**95,809.1**	**83,661.6**
Discount Rate 8% (-2%)	102,263.6	105,112.0	112,176.7	98,634.3
Increase (Decrease)	16,275.9	16,423.1	16,367.5	14,972.8
Discount Rate 12% (+2%)	73,874.2	76,443.3	83,367.3	72,171.6
Increase (Decrease)	-12,113.4	-12,245.5	-12,441.9	-11,490.0

7.4.4 *Load Forecast*

The sensitivity study on load forecast was carried out for selected scenarios (Scenarios 1, 3, 5 and 6) and the study results are presented in Table 7-7.

From the results shown in Table 7-7, one could understand that the total system cost is not a linear function of system load. It is important to note that comparing with the Base Case, addition of some generation units/plants would be delayed in the low load case while some would be advanced in the high load case. The ranking order of the four scenarios does not change within the analyzed load forecast range.

Table 7-7: Sensitivity Study Results – Load Forecast

Parameter/Variation	Scenario			
	1	3	5	6
Base Case	**85,987.7**	**88,688.9**	**95,809.1**	**83,661.6**
Low Load Forecast	78,638.3	81,509.5	88,865.8	76,301.5
Increase (Decrease)	-7,349.3	-7,179.4	-6,943.3	-7,360.0
High Load Forecast	96,988.2	100,075.7	106,570.6	94,769.9
Increase (Decrease)	11,000.5	11,386.9	10,761.5	11,108.4

7.4.5 *CO_2 Emission Offset Allowance*

The sensitivity/impact of CO_2 offset allowance on the total system cost is presented in Table 7-8. The analysis was carried out for two values, N$ 60 per Tonne and N$ 200 per tonne. As the total amount of offset allowance is a linear function of the offset allowance per tonne, the two cost values could be used to calculate any other offset allowances on CO_2. The last row of the table shows the increase in total system cost for every N$ 10 per tonne increase in CO_2 offset allowance. The results indicate that even with this significant range in the amount for the CO_2 offset allowance there is no change in the ranking order of these coal (Scenarios 1 and 6) and natural gas (Scenarios 3 and 5) based scenarios.

Table 7-8: Sensitivity Study Results – CO2 Emission Offset Allowance

CO_2 Offset Allowance (N$/Tonne)	Scenario			
	1	3	5	6
60	85,987.7	88,688.9	95,809.1	83,661.6
200	89,251.3	91,329.3	97,297.3	87,439.5
Difference	**3,263.6**	**2,640.4**	**1,488.1**	**3,777.9**
N$10/Tonne	**233.1**	**188.6**	**106.3**	**269.9**

7.5 Conclusions on Scenarios

7.5.1 Base Case Plan

The analysis of this section indicates that Scenarios 6 and 8 have total life cycle costs at the lower end of the range for all the above 11 scenarios and at the same time have balanced ratings on important non-cost criteria. While Scenario 7 is estimated to have higher life cycle costs it also scored well on a number of the non-cost criteria. Each of these scenarios satisfies the load forecast at the selected level of reliability and each has a slightly different mix of types/sizes of plants reflecting the operating characteristics and costs of each plant type. From these three scenarios, Scenario 6 was selected as the Base Case Plan (also referred to as Plan A) for the NIRP. As further developed in Section 8, a competitive bidding program is recommended to test the market including the costs of the fuel delivery infrastructure and the extent to which developers are willing to fix fuel prices for the base load generation fuels considered in Scenarios 6, 7 and 8. This process will allow the base load component of Plan A to be finalised.

7.5.2 Large Local Resource Project Realization - Alternative Path

Plan A does not include the Kudu and Baynes projects, both of which are considered to be heavily dependent on Government of Namibia investment, externalities beyond the direct control of the Government of Namibia and development decisions that may be hard to finalise in the timeframes needed to meet the projected power requirements for the next decade. Plan B is taken to be Scenario 5 which includes both Kudu (2021 on-line date) and Baynes (2026 on-line date). Plan A could transition to Plan B when the current hurdles to the Kudu and Baynes projects are overcome.

7.5.3 Renewable Prioritization - Alternative Path

A High Renewables option could also be selected if the international support on which the INDC is predicated materialises. This would be a variant on Plan A and could involve Scenario 9, 10 or 11 depending on the outcome of the bidding process or Plan B. Any of these Scenarios would achieve the 70% annual kWh generation from renewables that is put forward as the target by 2030 in the INDC.

7.5.4 Conclusion

The Base Case Plan (Plan A) is further elaborated in Section 8.

8. Implementation Plan for the NIRP

The previous section concludes that the path forward for the Namibian ESI should include three key activities as follows:

1. Secure access to short-term rental generation by 2018 or, if available at better terms, guaranteed access to power markets for electricity imports.
2. Install fossil-fuel base load generation by 2021.
3. Continue programs to install solar PV and wind generation and further investigate the use of other renewable power technologies.

The implementation plan for the NIRP presented in this section includes both short-term and medium-term project related activities as well as the ongoing process for monitoring the implementation of the plan.

Government will also pursue the realization of the Kudu and Baynes power projects at its discretion, and should one or both of these projects become realizable then implementation can be switched over to a plan that includes these projects.

8.1 Key Factors to Consider

The following are key factors to consider with respect to the implementation plan:

- The current level of reliance on imports (that sometimes extends beyond the contractual obligations for imports to the spot market) is perilous. In this regard it is noted that the 200 MW contract with ESKOM for import during peak load hours is subject to reduction if there is a need for load shedding in the ESKOM system.
- The existing “commitments” for renewables based projects in Namibia will do very little to secure the supply of power during peak load evening hours.
- There has not been a comprehensive study done to establish the level of intermittent generation that could be integrated in the Namibian power system.
- The use of government funds for direct or indirect investment in base load generation would reduce the government funding available for education, health care and other national priorities.
- Private sector offers for large power plants on a “non-solicited” basis is problematic as it is difficult to conclude to the satisfaction of stakeholders that project “x” is a more suitable project than project “y” may be.
- The indicated cost differences between alternative base load generation types/fuels are not large and could be outweighed by the risk factors associated with any particular project.
- The development of a thermal power station in the central coastal area could offer the opportunity to utilise waste heat for thermal based desalination of sea water and thereby contribute to addressing the water supply situation in Namibia. The potential benefit of this possibility should be considered when deciding on preferred technologies and sites.

- Most recently, ESKOM apparently has excess generation capacity available once again and has been seeking to sell this capacity. If this is the case, and this capacity can be made available on secure terms, an acceptable price and for an appropriate timeframe then this could be considered instead of implementing the local reciprocating engine based emergency generation. This implementation plan however proceeds on the assumption that this may not be the case.

8.2 Recommended Implementation Plan for NIRP

The path forward for implementation of the NIRP is recommended to be as outlined below. Table 8-1 provides year by year details on the implementation plan. The details shown in this table are for Scenario 6 (which includes coal-fired base load generation) and will vary depending on which generation technology and fuel type is selected in point 2 below.

1. In the absence of firm supply commitments from regional suppliers, complete arrangements for 120 MW of emergency generation that NamPower has already received bids for. The contract should allow for the suitably documented fixed costs of the project to be paid in full. Plant dispatch is to be fully controlled by NamPower at an agreed variable O & M cost, plus actual fuel cost. Starting in 2018, contract term of 3 to 4 years extendible for up to three 1-year periods should be considered. International consultants are to be retained to vet the contract and project implementation based on international standards.

2. Carry out an international competitive bidding process for approximately 300 MW (the exact capacity is to be based on unit sizes available from preferred bids) for coal, LNG or HFO fuelled base load generation, which is to be in full operation by January 1, 2021. The project is to be built on a designated site which is owned by Government of Namibia prior to the bids. The site should be selected to require minimum cost for transmission to connect the project to the grid. Water supply should require dedicated desalination by the power plant developer, if relevant. The cost of fuel landing and transport arrangements should form part of the tender, or be separately assessed by Government and taken into consideration in the tender evaluation. A suitably qualified international consultant is to be directly responsible for the evaluation of the bids and recommending the winning bidder based on criteria agreed on in advance with the Government, and should be a key member of the implementation team to ensure transparency.

3. Require that MME commissions and completes a comprehensive renewables grid integration study. This will be important to ensure that the country's solar and wind resources can make an effective contribution to the power system.

4. Continue with the program for private sector investment in solar PV and wind power plants as shown in the implementation plan through competitive bidding, ensuring that prices and terms offered are attractive enough to incentivise investment.

5. Require that MME commissions and completes a feasibility study on encroacher bush based biomass power plants. If the study shows this option to be reasonably attractive, seek funding for a 5-10 MW demonstration / pilot plant to test/confirm the operational aspects of such a power plant. With these activities completed and assuming positive

results, the implementation plan includes installation of small encroacher bush based biomass plants beginning in 2023.

6. Require that MME commissions and completes a feasibility study on concentrated solar power plants. The implementation plan includes installation of CSP plants beginning in 2026.

7. Continue development work on the Kudu and Baynes projects with the objective of reaching a decision by September of 2020; on implementation of either or both projects with target implementation dates in the period between 2025 to 2030.

Table 8-1: National Integrated Resource Plan – Implementation Plan and Schedule

Year	New Generation Addition (1)							Retirement		System	New Generation Investment Cost (4), (5)		Energy Production				Load Forecast	
	Renewable (MW) (2)					Thermal (3)	Import	Plant	Capacity	Capacity	Renewable	Thermal	Renewable (2)	Thermal	Import	Total	Peak	Energy (2)
	Hydro	Solar PV	Wind	Biomass	CSP	0			MW	MW	N$ millions		GWh				MW	GWh
Existing	346.5	9.5				135.8	330			821.8								
2015											1,200.8							
2016										821.8	2,744.4		1,530.0	923.4	1,788.1	4,241.5	645.7	4,241.5
2017		70					20			911.8	1,295.9		1,713.9	928.0	1,907.2	4,549.2	692.5	4,549.2
2018		50	49			120		Paratus & Imp	26.3	1,104.5	343.1	3,305.1	2,011.2	1,598.3	1,170.6	4,780.1	733.4	4,780.1
2019										1,104.5	228.7	4,406.8	2,011.2	1,656.0	1,263.1	4,930.3	758.4	4,930.3
2020		20								1,124.5	1,108.4	3,305.1	2,063.8	1,697.8	1,338.6	5,100.2	785.9	5,100.2
2021						300		ICRE & Imp	370	1,054.5	1,048.1		2,063.8	2,701.2	522.7	5,287.7	815.9	5,287.7
2022			50							1,104.5	755.3	3,305.1	2,217.1	2,694.8	531.3	5,443.2	841.7	5,443.2
2023										1,104.5	537.9	4,406.8	2,217.1	2,797.4	591.7	5,606.1	868.5	5,606.1
2024		20		20						1,144.5	1,869.5	3,305.1	2,436.0	2,775.7	581.2	5,792.9	898.5	5,792.9
2025						300		Van Eck & Imp	188	1,256.5	2,573.1		2,423.3	3,422.6	145.0	5,990.9	930.7	5,990.9
2026		20								1,276.5	4,573.5		2,475.9	3,635.8	85.1	6,196.9	963.8	6,196.9
2027					50					1,326.5	3,083.3		2,826.3	3,532.9	65.5	6,424.8	1,001.0	6,424.8
2028			50	20						1,396.5	2,178.7		3,146.0	3,454.1	55.1	6,655.2	1,038.7	6,655.2
2029					50					1,446.5	2,167.4		3,483.6	3,369.1	42.6	6,895.3	1,077.6	6,895.3
2030		20								1,466.5	2,996.7		3,536.2	3,545.6	65.1	7,146.9	1,118.5	7,146.9
2031				20						1,486.5	3,693.8		3,702.7	3,623.0	79.4	7,405.1	1,158.7	7,405.1
2032		20			50					1,556.5	3,870.9		4,092.8	3,487.6	55.1	7,635.6	1,195.4	7,635.6
2033				20						1,576.5	3,561.7		4,259.3	3,586.4	72.2	7,917.9	1,239.3	7,917.9
2034					50					1,626.5	1,526.4		4,596.9	3,523.8	60.2	8,180.9	1,280.7	8,180.9
2035					50					1,676.5			4,947.3	3,488.0	54.2	8,489.5	1,328.5	8,489.5
Total	**346.5**	**229.5**	**149**	**80**	**250**	**855.8**	**350**		**584.3**		**41,357.7**	**22,034.0**						
	1055					**1205.8**		**584.3**										
	1,677																	

Note: (1) For Scenario 6 of Option 2
(2) The values shown do not include the contribution of Solar PV installations implemented under the Net Metering Program
(3) Assumes the short-term emergency diesel generators would be rented and there would be no investment cost
(4) Annual capital investment flow as per the typical capital disbursement schedule for each type of new plant
(5) The capital investment required for solar PV installations under the Net Metering Program is not included

The total cost (capital and operating over the period 2016 to 2035) of the recommended plan is in the range N$ 83,662 million to N$ 96,139 million. At the lower end of this scale, based on coal-fired base load plant technology, the cost would be made up of the components shown in Table 8-2.

Table 8-2: Estimated Present Value of the Total Cost of the Recommended Plan

Item	N$ Millions
Capital cost	17 924
Fuel cost	13 427
O&M cost	33 904
Unserved energy (EUE)	761
Emissions	1 366
Subtotal	**67 382**
15 year end-effect	16 279
Total	**83 662**

8.3 Monitoring, Review and Update of the NIRP

The following actions are recommended to be put in place to ensure that implementation of the NIRP proceeds as planned, and that the NIRP is kept updated as circumstances and technologies change:

1. By the end of 2016, appoint a Steering Committee to review progress on the NIRP every 6 months, and formally report to the Minister of Mines and Energy within two weeks of every semi-annual meeting and recommend plausible actions. The Committee should be chaired by the MME, and include representatives of the ECB, NamPower, NAMCOR, the National Planning Commission, Ministry of Finance, Ministry of Environment and Tourism, the electricity distribution industry, and IPPs.
2. The Committee should annually review the major advances in technology, technology prices and the load forecast, and make recommendations to the Minister MME when such changes necessitate an adjustment or full review of the NIRP. Future reviews should also consider the potential impact of off-grid solutions.
3. From the onset and in subsequent reviews, the NIRP compliance with provisions of the Grid Code must be ensured. This compliance requirement equally applies to the Renewable Energy Policy as well.
4. Independent of the above annual review by the Committee, the NIRP should be fully reviewed and updated by the MME at intervals not exceeding five years.
5. The Committee should determine at what intervals the renewables grid integration study is to be reviewed and updated, to take actual developments into consideration, as well as advances in technology and other factors that could affect the results of such a study.
6. Electricity storage is considered a potential game-changer for the capability of the system to accommodate intermittent generation sources, and the ability of renewables to contribute capacity during peak demand periods. The Committee should therefore monitor the technical and cost developments of storage technologies as part of the implementation of the NIRP, and bring these on board once mature and economically viable.

Appendix A:
Terms of Reference

Appendix B:
Data Collection Items

Appendix C:
Unit Addition/Retirement Schedules