Pre-Feasibility Study Report

Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

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EXECUTIVE SUMMARY

WorleyParsons undertook, on behalf of the CEB, a pre-feasibility study to assess the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius. The CEB commissioned this study with a view to reduce the dependency on conventional imported energy carriers, to promote the use of cleaner energy sources and to diversify the energy mix of the country.

The following sources of potential LNG demand were considered in the study:

- Conversion of the existing CEB thermal stations
- A new 100MW Natural Gas Fired Power Plant
- Transport sector conversion to use natural gas (NG)
- Additional sources from commercial and industrial sectors

Power Assessment

Conversion of Existing Oil Fired Power Plants to LNG firing:

- Conversion of the reciprocating engines at the Ft George power station from HFO to LNG is not feasible as the OEMs do not offer gas conversion kits for the installed units.
- Conversion of 9 Wärtsilä reciprocating engines from HFO to LNG and representing 133 MW of effective generating capacity is feasible for the Ft Victoria G1-G6 and St Louis Power G7-G9 units.
- Conversion of the Nicolay gas turbines from HFO to LNG is not recommended because of their low utilization which would not support a cost effective investment.

New 100 MW Gas-Fired Generation:

- The General Electric LM6000PF gas turbine generators in a 2x2x1 GTCC configuration was found to have the lowest levelized cost of electricity (LCOE) of the three options considered. The three options included an aeroderiviative GT, an industrial GT, and reciprocating engines. The LM6000 based option show significant robustness under various sensitivity analyses including capital cost, fuel cost and capacity factor variations.
- The installation of the new 2x2x1 LM6000 based GTCC is considered feasible. The new plant would fit in the available space at the Les Grandes Salines site and the three generators are appropriately sized (<50 MW) for the small island network. The project duration is estimated at approximately 25 to 27 months from NTP to commercial operation.

The annual LNG consumption of the Base Case power conversion scenarios (including new 100 MW GTCC, 6 Ft Victoria and 3 St Louis unit conversions and 4 new St Louis 15MW units) range from 0.11 to 0.15 MTPA in the first full year of operation in 2019 (for low to high electric growth projections). The annual consumption of the aggressive power conversion scenarios (including the Base Case plus replacement of the unconvertible units: Ft George G1-5, Ft Victoria G8-9, St Louis G1-5.) range from 0.20 to 0.27 MTPA in the first full year of operation in 2019.

Transport Sector Assessment (incl. Commercial and Industrial)

In the LNG Import Infrastructure Assessment section, it is seen that a Floating Storage and Regasification Unit (FSRU) terminal is the preferred technical option. For this reason supplying NG to the transport, commercial and industrial sectors involves the compression of the pipeline gas at a compression site, fed by the incoming gas pipeline from offshore, and the transportation and sale of compressed natural gas (CNG).

It was found that a countrywide gas pipeline infrastructure would prove to be difficult to justify economically. All gas clients distant from the main port would need to be supplied in bulk by road tanker, at least for the short to medium term.

Transport Sector

- The study presents an overview of the world NGV market and extrapolates a possible market uptake in the transport sector for Mauritius.
- Various conversion technologies and options exist and the possibility of OEM manufactured vehicles has been established.
- LNG demand projections are made over a 15 year period assuming a 2% vehicle market growth and considering that the build-up would be, due to the thousands of decisions to be made, a more gradual evolution, typically slower over the initial 3-5 years (majority of end users preferring to wait for the technology to be proved in country before committing) then accelerating thereafter.
- After 15 years, a probable LNG demand could be in the order of 0.09 MTPA to 0.14 MTPA for a low and high case respectively.

Commercial and Industrial sectors,

- medium term base case gas market share of 5% has been used for each sector (based on recent history; no growth has been assumed), restricted due to the fact that gas consumers would need to have relatively large demands to justify cost effective bulk delivery of CNG by truck.

The scoping economics performed conclude that from the End User and CNG trading company perspectives, feasible cases can be built given the range of LNG prices and CNG tariff as determined by the financial modelling. However, although over the longer term the development of a strong NGV market would gradually add to the LNG demand, a LNG importation scheme in Mauritius would need to be initially justified (“anchored”) by a long term commitment for a suitable minimum demand from the power sector.

LNG Import Infrastructure Assessment (incl. Port and Marine)

Under the Base Case, the total annualized LNG demand in 2019 is projected to be approximately 0.13 MTPA growing to around 0.3 MTPA in 2032. For the High case, this increases to 0.27 MTPA in 2019 and grow to 0.65 MTPA in 2032.

For the LNG Import Infrastructure Assessment, a 1 MTPA terminal requirement has been assumed as the basis for this study. Although it is noted that this capacity may be too large considering the presently projected demand in Mauritius; it was selected to have a chance to create sufficient economies of scale to lower unit cost for the import terminal. Smaller scale LNG infrastructure has not been considered for Mauritius due to the lack of suppliers willing to load smaller LNG carriers, potential small scale sources being too distant and applicability of small LNG carriers for long distance shipment.

The result of this prefeasibility assessment shows

- that the site designated, in the vicinity of the existing port terminal at Port Louis, is suitable for the installation and the construction of a marine LNG import terminal; the existing marine infrastructure, however, does not offer the possibility to accommodate berthing of LNG carriers and a dedicated import terminal will need to be developed.
- On the basis of a preliminary options appraisal exercise a 173,000 m^3 FSRU terminal option has been selected. The concept adopted will follow the near shore LNG import Terminal. To allow greater flexibility in LNG supply from LNGC a dual Jetty concept has been proposed. The Jetty will have Marine Loading Arms (MLAs) for transfer of LNG from LNGC to jetty and another set of MLAs for transfer from Jetty to FSRU. HP Arm will transfer Regas NG from FSRU to Jetty. The Regas NG will be transferred to On-Shore Receiving Facility (ORF) by sub-sea pipeline. The ORF will broadly have Filter, Pressure Let Down and the metering station.

LNG Supply Chain

Mauritius should be able to procure LNG in the spot/Short-term market (for the Base Case), and potentially in a long-term contract for the High Case scenario. LNG will in all likelihood be sold to Mauritius on a Delivered Ex-Ship basis (DES). Projections for the period 2014 to 2030 are given in Exhibit 6-21.

The study generated projections for LNG burner tip cost that incorporates the unit cost for the LNG terminal (as calculated in the financial analysis) with the LNG DES prices (low, medium and high scenarios) and the Base and High Case volumes for a period of 12 years. This is then compared to the projected DES cost of HFO. See comparison graph in Exhibit 6-23.

It was clearly demonstrated that even for the High Case demand scenario, neither the near nor long-term LNG cost projections provided cost savings versus HFO.

Options for increasing the economic feasibility for using LNG vs. HFO are discussed; all of which are future considerations (i.e. not feasible in the short term) and would require further investigation:

- New potential sources of LNG that are being developed in East Africa that could result in lower LNG prices resulting form of a government-to-government agreement;
- the possibility of using small scale LNG terminal infrastructure; and
- the option of bunkering to increase LNG demand.

Schedule and CAPEX

A level 2 Implementation plan was prepared for the preferred technology options using the start of this Pre-feasibility as the start date; some highlights are:

- The Planned Completion date for the Mauritius LNG Project is July 2019 (43 months after EPC award) and includes Detailed Engineering, Procurement, Construction and Commissioning with phase durations
    - LNG Import Facilities = 32 months

  - o 100MW Power Plant = 29 months
- First Gas to be received by 1st June 2018 and 100MW Power Plant Commercial operation 7 September 2018.

The CAPEX estimate was used as input for the Economic and Financial Modelling. The estimate has an expected estimate accuracy <± 50% (before contingency) which is fitting for a study at this level. The total overnight EPC CAPEX estimate, excluding contingency is $329,140,988 of which $131,549,331 is attributed to the LNG import facility, $126,990,734 for the new 100MW power plant and $45,990,000 for the conversion of Fort Victoria and St. Louis Power Plants. A 20% contingency is added to the CAPEX figures estimated and is believed to be suitable at this stage of the project.

Economic and Financial Modelling

The financial projections for the LNG terminal and 100MW power plant are based on standard private sector project finance assumptions that should be obtainable in the Mauritiun market.

Key conclusions for the LNG Regasification Terminal

- The minimum practical terminal size results in a facility that is underutilised for the most part during the evaluation lifetime of the project.
- This result in a regasification tariff that is higher than what would normally be expected from a facility of this nature that is more optimally utilised; e.g. on the order of 15.76 USD/MMBtu for the Base Case demand in 2018.
- From the sensitivity analysis, it is seen that the biggest sensitivity is the throughput (for instance for High Case and 65% loading, regas tariff reduces to 6.77 USD/MMBtu). It is however noted that under the higher utilisation scenarios, the market reaches saturation before the plant reaches it full utilisation. Therefore, the processing is constrained to the market's ability to absorb the product processed.

Key conclusions for the 100 MW Power Plant

- Based on the regasification tariff required to make an economic case for the Terminal and the assumed LNG delivered cost it would be difficult to justify the cost of power generation from the CCGT Power Plant if it is operated at a Base Case of 50% dispatch factor. The resultant tariff is 0.29 USD/kWh in year 1.
- As can be seen from the sensitivity analysis, the economic case improve dramatically when a high growth scenario is assumed and the new 100MW the Power Plant is operated at a dispatch factor of 65% or 85% i.e. 0.21 USD/kWh and 0.20 USD/kWh respectively.

Conclusion & Recommendations

Although the import and use of LNG for power generation and transport, commercial and industrial sectors is technically feasible, it would be commercially challenging, in the current conditions. The main driver is the low LNG demand from the sources considered. This leads to underutilization of costly LNG import infrastructure and difficulty in sourcing such low volumes of LNG at acceptable prices.

Some ways to increase the demand for LNG could be through further exploration of bunkering, hub and spoke model to Reunion, refining activities etc. Also, it is possible that the supply dynamics (e.g.

new East Africa findings and development) and small scale LNG infrastructure developments may become more attractive in the future and it is advised that this study be revisited in due time using appropriate revised assumptions.

The scope of this study excluded an investigation into the non-financial factors (incl. environmental, social and economic impact) that can be considered in order to motivate the case for LNG import and use in Mauritius; these could be quantified and included in an economic analysis supported by further study. Considering high national importance, special government funding and/or tax / investment incentives may be proposed to stimulate market uptake of LNG.

SUMMARY

Introduction

This report describes the Pre-feasibility study undertaken by WorleyParsons on behalf of the CEB to assess the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius.

Background [41]:

Mauritius has no known oil, natural gas or coal reserves, and therefore depends heavily on imported petroleum products (heavy fuel oil, diesel and kerosene) to meet most of its energy requirements. As a result, electricity generation remains the greatest contributor to greenhouse gas emissions in the country. Electricity generation in Mauritius is essentially carried out by the Central Electricity Board (CEB), which operates under the aegis of the Ministry of Energy and Public Utilities (MEPU), and Independent Power Producers (IPPs). In 2011, CEB produced about 45% of the country's requirements from its 4 thermal power stations and 9 hydroelectric plants which have a combined capacity of 389 MW. The remaining 55% of energy requirements was purchased from independent power producers.

Local and renewable energy sources are biomass, hydro, solar and wind energy. Biomass energy consists mainly of bagasse, a by-product of the sugar industry, and contributes about 16% of the primary electrical energy supply. Fuel wood and charcoal are minimally used, but not for generating electricity. Hydropower plants, with a combined installed capacity of 59 MW, represent virtually the entire hydro potential.

To cater for the growing demand it is envisaged to redevelop the St Louis Power Station with installation of 60 MW diesel engine capacity in 2016 and set up a 100 MW coal power plant which shall come into operation in 2017. Also, there are two projects in the pipeline for the setting up of wind farms in the country.

Objective:

The CEB commissioned this study with a view to

- reduce dependency on conventional imported energy carriers,
- promoting the use of cleaner energy sources,
- further diversifying the energy mix of the country by gradually shifting away from conventional energy sources (HFO) through the use of Liquefied Natural Gas (LNG) for electricity generation.

The detailed Objectives and Scope of Services for this study is presented in the Inception Report as attached in Appendix 1. In short, the main objectives are to provide the CEB with a general overview of LNG power generation and import technologies, current state of the global supply chain and market dynamics, and to provide a conclusion on the feasibility to use LNG, given the provided set of parameters, in Mauritius for power generation.

Methodology summary:

For this study, it was considered that the CEB would build an additional 100MW Natural Gas (NG) fired power plant in order to generate power sector demand for NG. The NG demand would further be enhanced by converting the existing CEB thermal stations to run on NG and phasing in the conversion of the transport sector from conventional fuels to NG. Other possible demand sources were considered at a very high level including Commercial and Industrial users.

A screening study was performed to determine the most suitable NG fired new 100MW power station technology and configuration. Recommendations for the conversion of the existing CEB stations were presented. The transport sector was investigated and an implementation plan derived. Using assumptions for power plant capacity factors and projections on the uptake from the transport, commercial and Industrial sectors; a base and aggressive case for annual LNG demand was estimated.

Based on the demand projections, requirements for the LNG import infrastructure, both from storage and regasification terminal considerations, were determined. A screening study was performed to determine the most suited technologies. This included an estimation of the port and marine aspects of importing LNG required for the LNG import solution.

The demand projections was also used to review the available LNG supply chain given the current state of the world LNG supply market and dynamics; an estimated supply price for LNG to Mauritius was concluded.

Given the resulting preferred options derived from abovementioned technology screenings, a consolidated implementation plan and CAPEX spend estimate was compiled. This was used as input into the financial models, in conjunction with the LNG supply price, and a NG tariff after the Regasification Terminal and a Levelized Cost of Electricity (LCOE) for the new power plant was estimated. Conclusions are drawn about the feasibility of using LNG in Mauritius under the given scenario.

Although outside the scope of this study, a short discussion is also presented on the non-financial aspects that can be considered for further evaluation including a high level analysis on obtaining carbon credits for this project under the CDM.

The following sections of the executive summary provide more detail on the respective activities.

Power Assessment

In support of CEB's objective of using LNG in their power sector, WorleyParsons evaluated the following two sectors:

a) Conversion of the existing oil fired power plants
b) Proposed 100 MW generation capacity additions

Conversion of Existing Units

Key information regarding the four existing CEB thermal Power Stations on Mauritius is presented in Exhibit 0-1.

Exhibit 0-1: Existing CEB Thermal Plant Characteristics

Plant	Prime Mover	Primary Fuel	Effective Cap. (MW)	Annual Load Factor note 1 (%)	Service
Ft George	Diesel Engines	HFO 380 cSt (heated)	134	55%	Base loaded
Ft Victoria	Diesel Engines	HFO 180 cSt	107	35%	Daily Start Stop (Semi Base)
St Louis	Diesel Engines	HFO 180 cSt	71	30%	Daily Start Stop (Semi Base)
Nicolay	Gas Turbines	Jet A1 (kerosene)	74	3%	Daily Start Stop (Peaking)

Note 1: Annual Load Factor per Integrated Electric Plan Forecast, 2013-2022 [3]

Conversion of an existing diesel engine based power plant from heavy fuel oil to natural gas (or regasified LNG) involves many design considerations. The feasibility of the diesel engine conversion is effectively determined by the availability of a conversion kit from the Diesel Engine OEM. As such, WorleyParsons has communicated with the diesel engine OEMs for the specific models installed at the CEB sites.

The potential conversion of the existing CEB power plants to LNG is summarized in Exhibit 0-2.

Exhibit 0-2: Estimated LNG Consumption from CEB Power Plants

Plant	Convertible Units	Capacity of Converted Units (MW)	Notes
Ft George	None	0	No conversion kits are available.
Ft Victoria	G1-G6	90	Conversion kits available for 6 Wärtsilä 15MW units.
St Louis	G7-9	41.4	Conversion kits available for 3 Wärtsilä*13.8MW units.
Nicolay	G1-G3	74	Not recommended for conversion - low utilization as discussed in Section 1.2.5.
CEB Plants		**205.4**	**131 MW w/o Nicolay**

Some highlights of the conversion of the convertible Wärtsilä engines (all Wärtsilä 6V46) are presented below:

- Convertible to Wärtsilä 16V50SG for gas only operation, or 16V50DF for tri-fuel operation (gas, LFO, HFO)
- The design and performance of converted units will be essentially that of new units.

- Conversion would be performed completely onsite at an EPC cost of approximately USD 350/kW based on 1st qtr 2014 estimate. This cost is inclusive for all necessary plant changes, but exclusive of owner's costs[1].
- The converted units would be substantially more environmentally friendly when firing natural gas as illustrated in Exhibit 0-3.

Exhibit 0-3: Wärtsilä Engine Conversion Emission Benefits

Parameter	Unit	Typical HFO	Typical Gas	Notes
NOx Emissions	mg/m3	2000	375	
SOx Emissions	mg/m3	5300	15	For 3% S HFO.
Particulate emissions	mg/m3	50	10	

Reference: [9]

The Nicolay gas turbines are not recommended for conversion from Jet A1 to natural gas primarily because the low utilization of approximately 3% would contribute very little to reaching the critical LNG consumption, nor would the conversion prove cost effective in light of the cost of connecting the plant to the LNG source and cost of converting the units to LNG.

Addition of New Power Plant

Based on the discussions at the Kick Off meeting with CEB, it was agreed that the following technologies will be considered for the 100 MW generation capacity additions.

1. **Aero-derivative** Gas Turbines based combined cycle (GTCC) project
2. **Industrial** Gas Turbines based combined cycle (GTCC) project
3. A multiple **reciprocating engines** project

Following a screening evaluation, the following three Power Plant options were chosen for evaluation.

1. **Option 1:** (Aero) GE LM6000 PF gas turbine generators in 2x2x1 GTCC configuration
2. **Option 2:** (Industrial) Siemens SGT 750 gas turbine generators in 2x2x1 GTCC configuration
3. **Option 3:** (Reciprocating) 6x18.5MW Wärtsilä Reciprocating Gas Gen Sets in simple cycle configuration

These three options were evaluated on a Levelized cost of electricity (LCOE) basis using the inputs documented in Section 1. The overall LCOE as well as the LCOE breakdown is presented in Exhibit 0-4. The LCOE for the simple cycle gas engine based option (Option 3) is higher than those for the gas turbine combined cycle options (Option 1 & 2). Although the debt service and fixed O&M costs for Option 3 are lower than those of the GTCC options, the fuel cost contribution to LCOE for Option 3 is significantly higher due to its lower efficiency compared to the GTCC plants.

[1] Additional detail on owner's costs are provided in Section 7.3.2.3

Sensitivity analyses on capital cost, fuel cost, and capacity factor are documented in Section 1 and all demonstrate the robustness of the Option 1 GTCC selection for the parametric variations evaluated.

Exhibit 0-4: 100 MW Generation Capacity – Levelized Cost of Electricity by Option

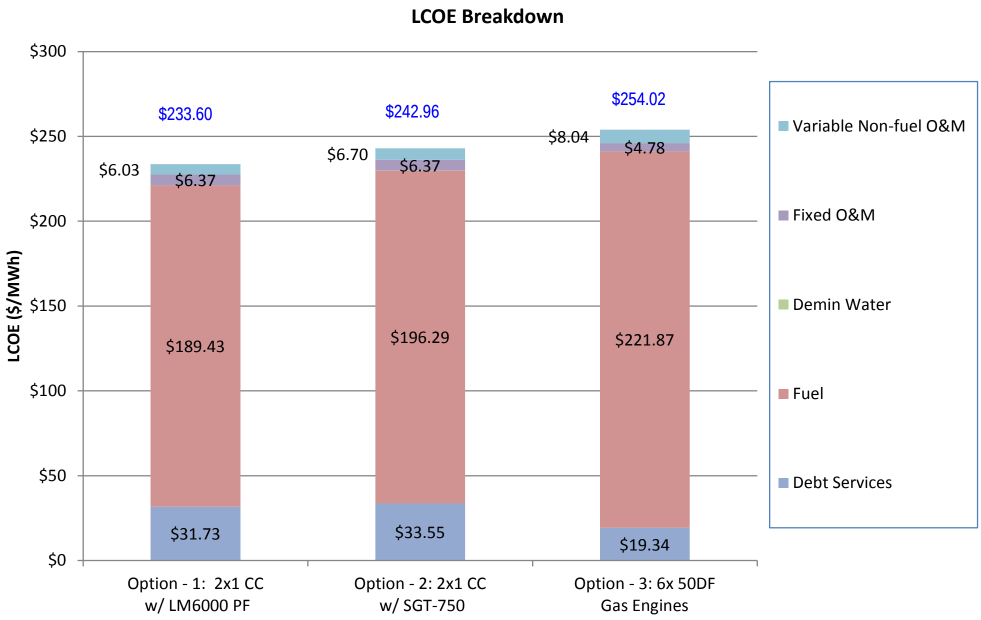
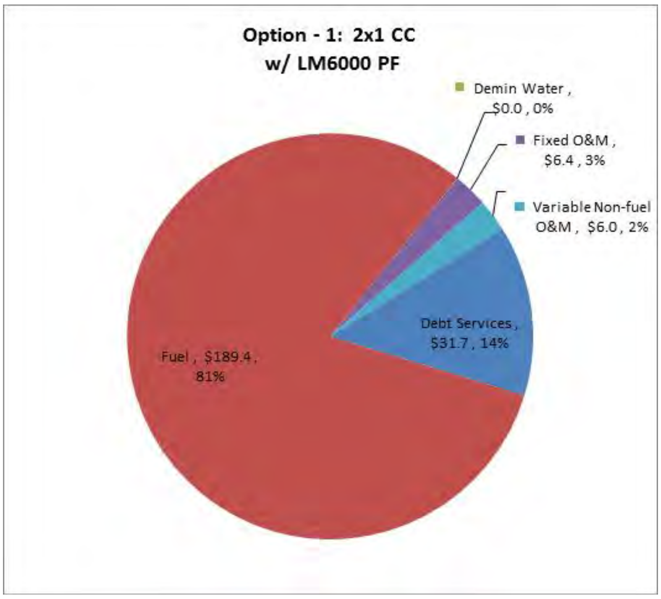


Exhibit 0-5 presents the breakdown of the LCOE for the least cost option (Option 1) in a pie chart with each component of the LCOE expressed in both $/MWh and % of the total cost. For this option, it can be clearly seen that the fuel cost is approximately 81% of the total LCOE cost, followed next by debt service at approximately 14% of the total LCOE.

Exhibit 0-5: 100 MW Generation Capacity – Levelized Cost of Electricity for Least Cost Option



The project schedule, from EPC notice-to-proceed (NTP) to commercial operation, for the candidate options are presented in Exhibit 0-6.

Exhibit 0-6: Power Plant Project Duration

Option No.	Option Description	Project Duration
1	2x1 GTCC Plant - GE LM6000 PF CTG (Aero)	Circa 25-27 months
2	2x1 GTCC Plant - Siemens SGT 750 CTG (Industrial)	Circa 25-27 months
3	6x18.5 MW Wärtsilä Gas Gen Sets (Reciprocating)	Circa 19-23 months

Based upon the above results, Option 1, the 2x1 GTCC based on the LM6000 PF, is recommended for consideration for the capacity addition at Les Grandes Salines. This recommendation is based on the option having the lowest LCOE of the three candidate options, as well as showing a significant level of robustness, evidenced by stamina under varying sensitivities including capital cost, fuel cost and capacity factor sensitivities.

Power LNG Supply Consumption

The amount of natural gas utilized by the CEB units depends on the new and converted existing units that are considered. For the sake of this analysis both a Base case and Aggressive case have been defined according to Exhibit 0-7. The Base case includes the new 100 MW plant and the existing units that can be converted to natural gas as indicated. The Nicolay gas turbine units are not included in either case, as their anticipated utilization of approximately 3% is judged too low to be cost effective in light of the cost of connecting the plant to the LNG source and cost converting the units to LNG. The Aggressive case includes the Base case units plus assumes replacement of the existing units that cannot be converted.

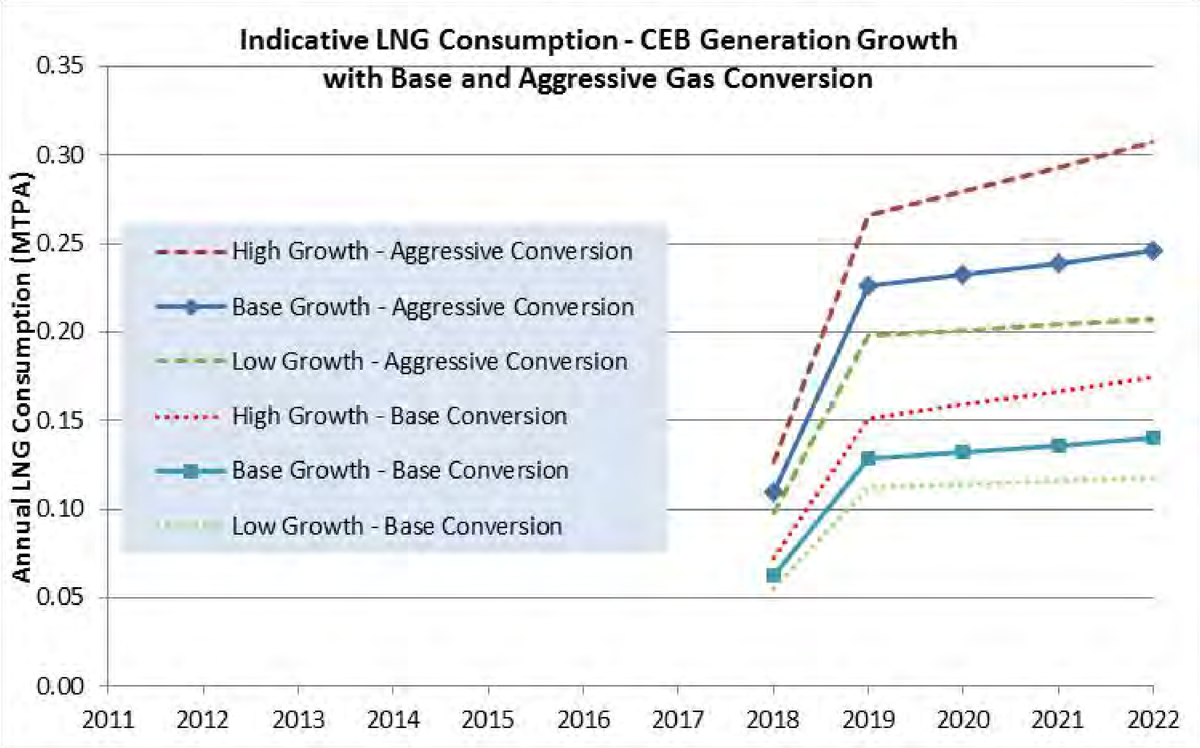
Exhibit 0-7: Natural Gas Conversion Cases

Item	Plant / Gas User	Plant Capacity (kW)	Base Conversion Case (kW)	Aggressive Conversion Case (kW)	Notes
1.0	**New Plant - Les Grandes Saline**	**97,930**	**97,930**	**97,930**	
2.0	**Existing Plants -Convertible to LNG**				
2.1	Ft George	0	0	0	No Conversion
2.2	Ft Vicotoria (6x15,200 kW)	91,200	91,200	91,200	G1-G6 W16V50DF
2.3	St Louis (3x13,800 kW)	41,400	41,400	41,400	G7-G9 W16V50DF
2.4	Nicolay G1-G3	75,850	N.R.	N.R.	G1-3 - GE Frame 5, 5, 6B
	Subtotal: Existing Plants -Converted	**208,450**	**132,600**	**132,600**	
3.0	**Existing Plants -If Replaced with New Units to burn LNG (Assume heat rate of W16V50SG - Gas only)**				
3.1	Ft George (2x24, 3x30 MW)	134,000	0	134,000	Replace G1-G5
3.2	Ft Vicotoria (2x8.5 MW)	17,000	0	17,000	Replace G11 & G12
3.3	St Louis (4x15 MW)	60,000	60,000	60,000	G1-G5 Retired. Replaced w/ 4x15 MW
3.4	Nicolay	0	0	0	
	Subtotal: Existing Plants -Replaced	**211,000**	**60,000**	**211,000**	
	Total of All Units	**517,380**	**290,530**	**441,530**	New, converted, replaced.

Notes:
1 N.R. - Not Recommended for conversion to LNG.
2 Conversion to LNG at Nicolay reflects 2.5% increase on capacity compared to oil firing.

In addition to the two conversion cases, (Base and Aggressive), there are also three different electric demand growth scenarios predicted by CEB (Low, Base, High). The indicative LNG consumption for both the Base Case and Aggressive Case LNG conversion, and for each of the three growth scenarios are presented in Exhibit 0-8. The LNG consumption information is based on LNG being available to the power plants in mid-2018. The annual LNG consumption of the Base Case power conversion scenarios (including new 100 MW GTCC, 6 Ft Victoria, 3 St Louis unit conversions and 4 new 15 MW units at St Louis) range from 0.11 to 0.15 MTPA in the first full year of operation in 2019. The annual consumption of the aggressive power conversion scenarios (including the Base Case plus replacement of the unconverted units at Ft George G1-5, and Ft Victoria G8-9) range from 0.20 to 0.27 MTPA in the first full year of operation in 2019. This information is utilized along with the transportation consumption in subsequent discussion.

Exhibit 0-8: Indicative LNG Consumption - Projected CEB Generation Growth and Base and Aggressive LNG Conversion Plot



LNG Potential for the Transport Sector (also incl. view on Commercial and Industrial sectors)

In addition to considering the potential LNG demand from the power sector, CEB wisely considered the broader demand for LNG that could potentially be derived from other sectors of the energy market. In the terms of reference for this pre-feasibility study WorleyParsons was asked to specifically investigate the potential for LNG demand from the transport sector and to consider the potential for use in the commercial and industrial sectors at a high level.

Section 2 of this report sets out how Natural Gas Vehicles (NGVs) have become, since the late 1990's, the leading alternative to petrol and diesel for motor vehicles, the reasons for this and how governments throughout the world have embarked on NGV programs very often with the aid of incentives and policies both encouraging and, in some cases, forcing the use of this cleaner fuel in certain niche sectors of the motor vehicle market.

The main body of the report also sets out to what extent NGVs have taken the place of petrol and diesel vehicles, listing the market share of NGVs in those countries where they have made a bigger impact. The report also sets out the significant benefits for end users and government if NGVs were successfully launched. Primarily these benefits could be summed up under the broad headings of environmental, public health, economic, reputational and general economic development.

The approach taken for this pre-feasibility study was to use all this experience gained throughout the world and to establish if NGVs could be economically attractive to local vehicle end users and the Mauritian government, and if so, to what extent and how quickly this could lead to a sustainable demand for LNG in the short to medium term, defined for this exercise over 10-15 years.

The use of gas in the Manufacturing and Commercial sectors worldwide mostly depends on the extent of natural gas pipeline networks. When available for these sectors natural gas is popular because it is clean burning, easy to operate and control, responsive to customer requirements and often competitively priced.

Following the short pre-feasibility visit to Mauritius it was agreed by the project team and local experts that a gas pipeline infrastructure in such a low density and rural country would prove to be difficult to justify economically. Under these circumstances all gas clients distant from the main port would need to be supplied in bulk by road tanker, at least for the short to medium term. It has been assumed that natural gas clients would be limited to power stations, together with larger scale manufacturing and commercial establishments and refuelling stations (public and private depot based private vehicle fleet installations) that could receive bulk deliveries of gas by an alternative distribution method (via road tanker).

For Mauritius the options would therefore theoretically have involved either the distribution of LNG or CNG by road tanker to larger clients in the manufacturing and commercial sectors and to gas refuelling stations for motor vehicles. However as this pre-feasibility study has developed it has been decided that a floating LNG terminal would be the recommended way forward due to the limited overall demand for gas, and the configuration proposed would involve the delivery to the shore of 40-45 bar pipeline gas and NOT LNG.

The proposed solution for the road transport and manufacturing and commercial sectors involves the compression of the pipeline gas to 250 bar at a compression site fed by the incoming gas pipeline from offshore and the transportation and selling of compressed gas (CNG).

When CNG is delivered, the CNG storage trailer is often “switched” and the empty trailer is removed from site and returned to the central facilities for refilling. A CNG station will comprise a CNG offloading facility, space for the trailer, a limited storage facility, a CNG pressure booster facility and some dispensers.

In order to get a sufficient supply of energy on-board a vehicle, gas is compressed up to 250 bar pressure and stored on vehicles at typically 220 bar. This pressure requires very robust steel or composite storage cylinders on-board the vehicle. A disadvantage of CNG when compared to gasoline or diesel is the storage space required and the weight of the storage facilities. CNG is suited to a wide range of vehicles, including passenger cars, taxis, vans, minibuses, buses and trucks. Various conversion technologies and options exist and the possibility of OEM manufactured vehicles has been established.

Specifically, for Mauritius, the potential market share for CNG vehicles was estimated, from worldwide experience, as below.

Exhibit 0-9: Mauritius Vehicle Population

Vehicle type	Number 2013	Gas share (%)	NGV's	km/annum	km/m^3	m^3
Cars (incl heavy motor cars & taxis)	158,442	12.5	19,805	40,000	11	720,19,091
Dual purpose vehicles / pickups	50,746	12.5	6,343	50,000	9	352,40,278
Vans	26,564	12.5	3,321	50,000	9	18,447,222
Buses	2,958	40.0	1,183	40,000	2.25	210,34,667
Lorries and trucks	14,023	8.5	1,192	40,000	3.6	132,43,944
Prime movers (i.e. tractor)	707	8.5	60	40,000	3.6	667,722
Total	253,440		31,904			160,652,924

Based on the growth of the vehicle market during the past 10 years a 2% per annum growth rate was assumed going forward. The build-up of demand for LNG from the vehicle sector, and indeed the manufacturing and commercial sectors would be, due to the thousands of decisions to be made, a more gradual evolution, typically slow over the initial 3-5 years then accelerating thereafter. The estimated build-up of demand, year by year is shown in Exhibit 0-19 and a volume demand after 15 years is given in Exhibit 0-10.

Exhibit 0-10: Estimated LNG volumes for the transport sector after 15 years

Case	LNG MTPA
Low Case	0.093
Base Case	0.116
High Case	0.140

Scoping economics were performed and it was found that from the End User perspective and CNG trading company perspective, feasible cases can be built given the range of LNG prices and CNG tariff as determined by the financial modelling further on in the report.

For the Commercial and Industrial sectors, based on recent history, it was assumed that the combined manufacturing / commercial demand would not grow going forward; because of the relative cost of LNG, it would not displace lower priced bagasse, wood, coal and charcoal. A medium term (15 years) base case gas market share of 5% has been assumed in each sector, restricted due to the fact that gas consumers would need to have relatively large demands to justify cost effective bulk delivery of CNG by truck. A table indicating how this demand would grow year by year is shown in Exhibit 0-19.

This study concludes that, although over the longer term the development of a strong NGV market would gradually add to the LNG demand (base case scenario indicates that after 15 years demand from these sectors could add up to an additional 0.126 MTPA of LNG), a LNG importation scheme in Mauritius would need to be initially justified ("anchored") by a long term commitment for a suitable minimum demand from the power sector. The reason for this is that both potential LNG suppliers and project financiers would need to see committed demand and thus guaranteed revenues from year 1 of the project. This would not be achieved from potentially thousands of NGV users at the start of such a program, the majority of end users preferring to wait for the technology to be proved in country before committing their vehicles to this new, albeit, exciting alternative fuel. The buildup of demand for LNG from the vehicle sector, and indeed the manufacturing and commercial sectors would be, due to the thousands of decisions to be made, a more gradual evolution, typically slow over the initial 3-5 years then accelerating thereafter.

Site Evaluation

Three sites were proposed as possible site locations for new 100 MW Power Plant:

1. *JinFei - Baie de Tombeau*,
2. *Old Port Site - Bois des Amourettes* and
3. *Les Grandes Salines*.

The first two sites were eliminated from further consideration during the Kick-Off Meeting visit based on inspection and mutual agreement with CEB.

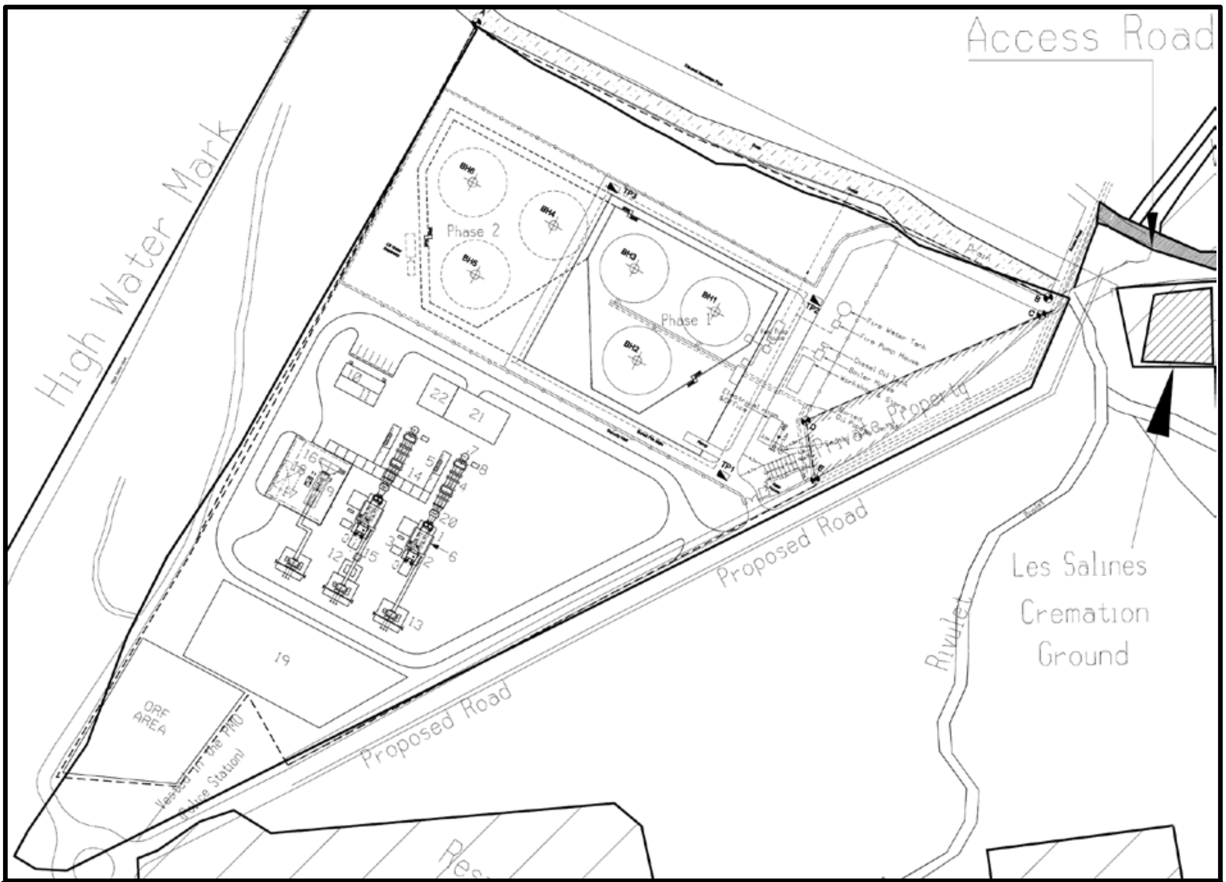
Power Plant considerations

The Les Grandes Salines site is considered a feasible site for the 100 MW Power plant based on the pre-feasibility study assessment of the following items:

1. High level footprint requirement for Power Plant
2. Proximity to Transmission line
3. Proximity to Residential area
4. Site Accessibility and transport infrastructure
5. Land Ownership
6. Proximity to the LNG tanker jetty

CEB owns the Les Grandes Salines site and has an option to buy addition land adjacent to the site if necessary. CEB is planning to put six 6,500 m^3 (each) HFO tanks at this site. The candidate site has sufficient room for either a combustion turbine or diesel engine power plant of approximately 100MW. This is demonstrated by a preliminary layout for 2x1 LM6000 combined cycle power plant as presented in Exhibit 0-11.

Exhibit 0-11: Les Grandes Salines Site with Gas Turbine Combined Cycle Power Plant

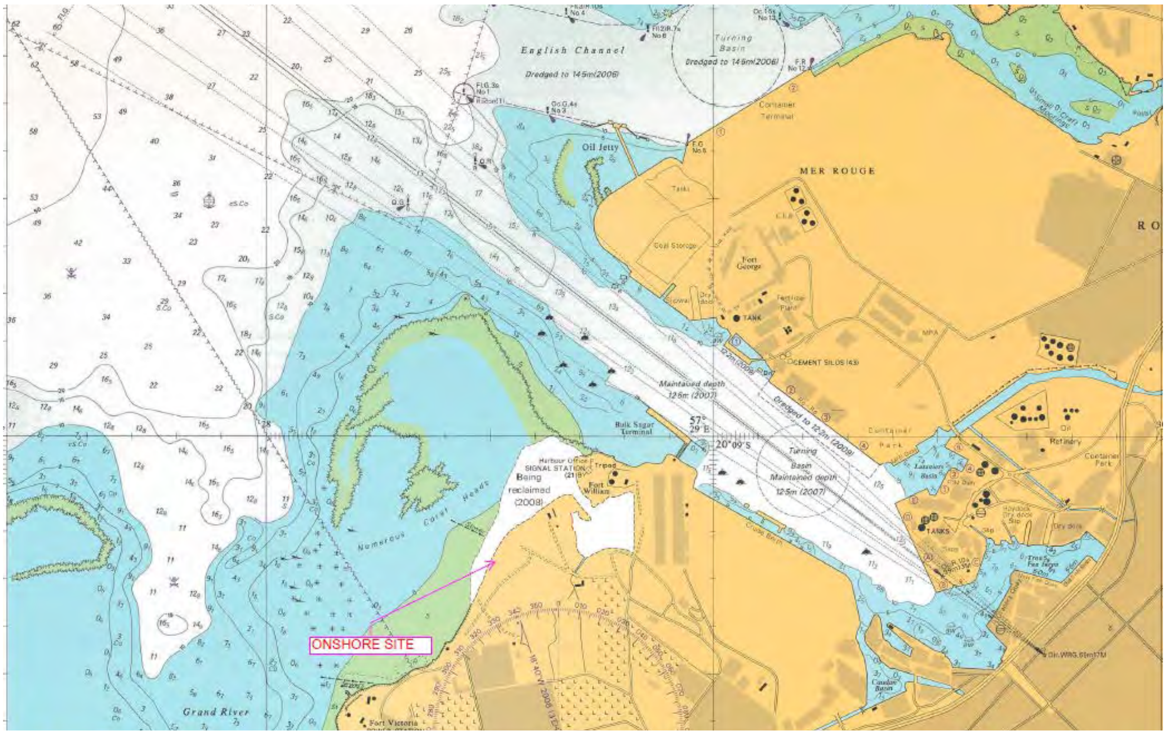


1 Combustion Turbine (CT)	9 Steam Turbine Generator	18 Steam Turbine Generator Bridge Crane
2 CT Generator	10 Electric Equipment Area (First Floor)	19 Switchyard
3 CT Oil Cooler	11 Admin / Control Room (Second Floor)	20 Bypass Stack
4 Heat Recovery Steam Generator (HRSG)	12 Auxiliary Transformer	21 Maintenance and Warehouse Building
5 Boiler Feed Pump	13 Step-up Transformer	22 Water Treatment Building
6 Air Intake	14 Utility Rack	
7 Stack	15 Generator Circuit Breaker (GCB)	
8 Continuous Emission Monitoring System (CEMS)	16 Steam Turbine Condenser	
	17 Steam Turbine Laydown Area	

<u>LNG import infrastructure considerations (incl. port and marine)</u>

Relevant met-ocean conditions, main environmental factor and associated risk for the site have been extrapolated based on observations made during the site visit and a desktop-based research of available data and information for the proposed offshore and onshore location for the LNG terminal (at Bain les Dames, Les Grandes Salines as shown in Exhibit 0-12).

Exhibit 0-12: Admiralty chart (Port Louis) and proposed site (Les Grandes Salines)



The result of this prefeasibility assessment shows that the site designated, in the vicinity of the existing port terminal at Port Louis, is suitable for the installation and the construction of a marine LNG import terminal. As being located on the west side of the island the shoreline is relatively protected from wind waves from the dominant south-eastern sectors and southerly ocean swells, which ensures a relatively high availability for offloading operations at berth.

The onshore site benefits from the presence of a shallow coral reef which helps preventing coastal erosion and protects the shoreline from wave action. Wave conditions in deep water, at further distance from the shore, are generally mild but may suddenly change in case of severe cyclonic events.

Cyclonic waves however can occur occasionally and cause significant damage to any coastal infrastructure and possibly cause inundations to the onshore proposed low-lying site (a number of cyclone-induced flooding events have been recorded over the years at the adjacent container terminal).

Cyclone is generally the main risk to be accounted for in the assessment of the proposed site: Mauritius has been visited by major cyclones on an average frequency of one in about 15 years and according to the latest Climate Change reports it is expected an increase in the frequency and intensity of future tropical cyclones, with larger peak wind speeds and heavier precipitation associated with the ongoing increase of sea surface temperature.

Hydrogeology and hydrology of the site and surrounding area should also be analysed during further design stage to identify any impacts associated with hydrological and hydrogeological risk. Cyclones may significantly and rapidly affect surface water runoff and groundwater flow and potential implications / consequences on site vulnerability should be considered.

More detailed quantitative environmental and Metocean data, some of which may be available from the Mauritius Port Authority (MPA) will be required for any further stages of this project, however as results of a preliminary screening, the site shows potentially suitable environmental and climate conditions to support LNG import operations.

LNG Import Infrastructure (incl. Port and Marine Assessment)

<u>LNG import terminal selection:</u>

Exhibit 0-13 presents a high level comparison of the various LNG import terminal technologies considered in this report.

Exhibit 0-13: Summary of LNG import Terminal types

Description	On-shore	Near Shore	Off-shore	Remarks
Capacity	Generally 3 MTPA or more	Generally 1-3 MTPA	Generally 1-3 MTPA	
On ground Area Requirement	10-20 ha depending upon capacity	1-2 ha	1-2 ha	
Off-shore requirement	Jetty for LNGC Berthing 120,000 to 265,000 m^3	Single or Dual Jetty	Suitable Mooring arrangement for Metocean and draft	
Off-loading	By Marine Loading Arms installed on Jetty	Single Jetty: FSRU moored to Jetty, Ship to ship transfer Dual Jetty: Both FSRU and LNGC moored to Jetty	Ship to Ship transfer	
Draft requirements	Generally ~12-16 m	Generally ~12-20 m	Generally~40-50 m	
Storage/ Containment System	Full Containment tanks	Moss or Membrane Tanks	Moss Tanks/ Membrane Tanks Note-1	membrane tanks would require careful consideration for sloshing
Off Loading	Marine Loading Arms	Marine Loading Arms/ hoses	Marine Loading Arms or hoses	
Feasibility to First Gas Schedule	Onshore Terminal ~ 48 months	Near shore Terminal 30-36 months	Off-shore 34-38 months	

Note 1: Membrane tanks would require careful consideration for sloshing

<u>LNG import marine terminal selection:</u>

The LNG marine infrastructure would generally include an LNG offloading berth, a navigational area with an access channel and a manoeuvring area and a number of gas processing facilities which are dependent on the terminal configuration.

The functional requirements assumed as Basis of Design during the pre-Feasibility study are listed in Exhibit 0-14:

Exhibit 0-14: Functional requirements

Item	Assumption
Throughput	LNG: 1 MTPA (114 tph, 250 m^3/h)
Range of vessels	Assume LNG membrane or moss type Containment system in vessels. Design Storage Capacity: 173,000 m^3
Size of LNGC & No. of unloadings per year	Assuming 125,000 to 150,000 m^3 LNGC, 250 m^3/h LNG continuous load, number of unloadings/ year are 18 unloading/year (i.e.once every 20 days)

It is observed that the terminal capacity (1 MTPA) assumed as basis for the Design may be too large considering the present demand in Mauritius; however for the purpose of the structural requirement definition during prefeasibility study this is considered a minimum requirement to achieve sufficient economies of scale to lower unit cost for the import terminal, which will be refined during future design stage.

A preliminary concept definition of marine facilities requirement was undertaken during this prefeasibility study. This includes:

- Assessment of existing Marine Infrastructure at Port Louis and possibility to accommodate berthing of LNG carriers
- Preliminary concept definition of a dedicated LNG import terminal

As result of the preliminary assessment and the visual inspection, the existing jetty is deemed not adequate for berthing of medium to large LNG vessels considering:

- The relatively small size of the loading platform which does not allow enough room for locating the necessary equipment for loading/offloading of LNG
- The need for widening the trestle and possibly retrofit the structure to accommodate placement of cryogenic pipeline
- The present dolphin configuration which may have to be revisited to assess its suitability for mooring of LNG vessels.

On the basis of the considerations made above it is likely that a dedicated jetty for LNG import will have to be installed.

An initial high level assessment of the main infrastructure requirements were undertaken for two concepts; with the other options eliminated by the terminal technology asessment:

- A floating option with a dual berth jetty
- A shore based LNG terminal connected to an offshore platform by means of a steel trestle.

These are shown in Exhibit 0-15 and Exhibit 0-16 respectively:

Exhibit 0-15: Shore based LNG marine facility

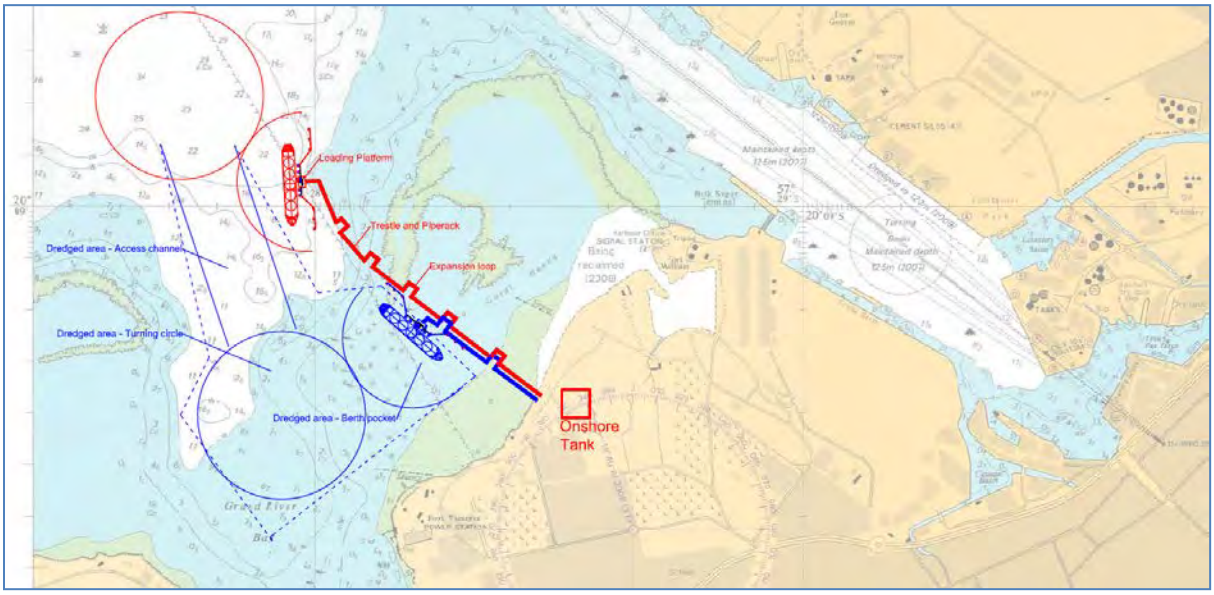
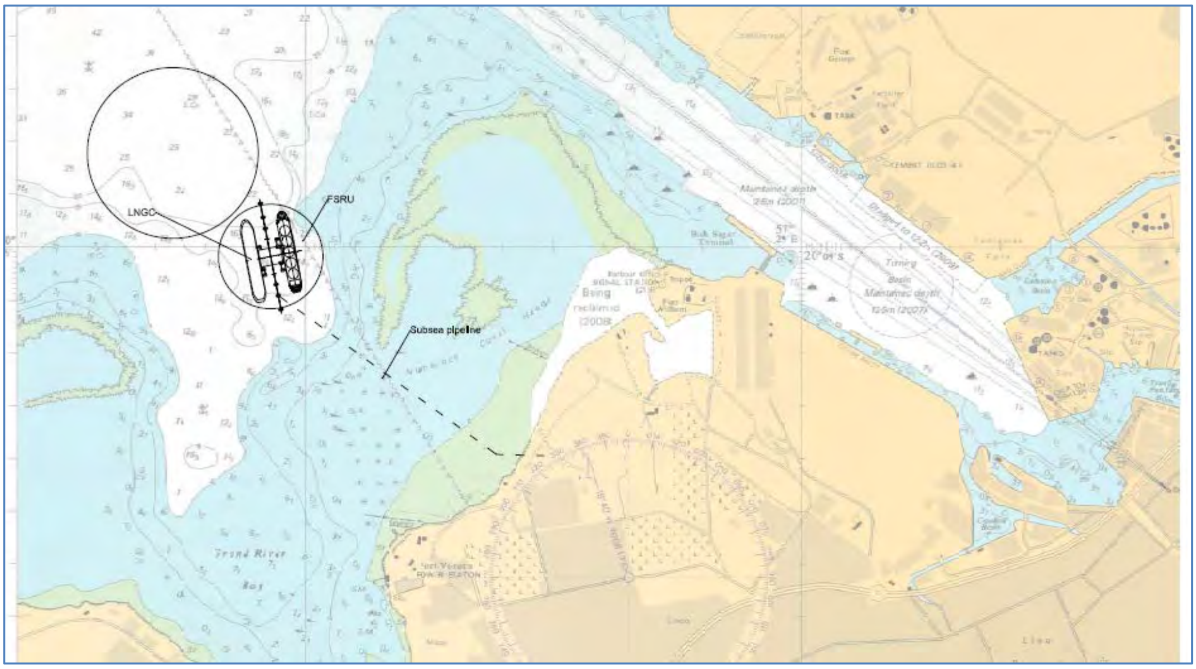


Exhibit 0-16: FSRU based LNG marine terminal



No detailed analysis on berth availability has been undertaken at this stage; nevertheless it is unlikely that a breakwater will be required considering the limited number of unloadings required per year.

Berth access will be planned in advance on the basis of adequate weather conditions and cyclone early warning systems will be adopted to prevent major accidents during terminal operations.

The floating option is initially positioned relatively far from the shore to minimise dredging activities and any related environmental impacts, whilst two optional configurations are considered for the shore based option: an offshore loading berth option connected to shore with a long steel trestle and a near-shore option which requires substantial dredging volumes.

A preliminary cost estimate (confidence range ± 50 %) including assessment of Capital and Operational expenditure (Capex & Opex) has been prepared based on WorleyParsons past project experience and database on similar projects for both options. The floating LNG option requires a smaller initial investment and has a relatively low capital cost, whilst the corresponding operational and maintenance cost is relatively high. Conversely the shore based option requires a significant initial investment that can be as high as 3 times the cost required for the floating option, but a smaller operational cost which is approximately 3 times lower than the FSRU option.

Also in terms of schedule the two options differ quite significantly: the floating option is based on the conversion of an existing LNG carrier into a FSRU unit which is then transported to site; while the shore based option will have to be entirely installed on site and will therefore require a longer construction schedule, which combined with the higher initial investment may make it less attractive. The shore based terminal on the other hand, may offer higher berth availability and lesser risk of cyclone induced disruption and/or structural damage; however given the relatively low number of LNG shipments per year and the highly effective cyclone warning system in place at Port Louis, there is a very low risk that a floating option will not achieve the desired target performance.

LNG import terminal: options appraisal

A comparison between the two technologies is also summarised in Exhibit 0-17:

Exhibit 0-17: High level options appraisal

	FSRU (dual berth type jetty)	Shore based terminal
CAPEX	Reduced initial investment	High initial investment
OPEX	High operational and maintenance costs	Reduced operational/maintenance costs
Schedule	Award of FSRU contract and construction of marine facilities will occur in parallel. Estimated construction schedule in the order of 24 months.	Driven by construction of the LNG Storage Tank. Overall construction duration may exceed three years.
Performance (Terminal availability)	Higher susceptibility to weather downtime.	Higher berth uptime and correspondingly high operational performance.
Safety	Offloading in potentially harsher environment. Need for cyclone warning system.	Need for cyclone warning system.

On this basis, and also considering the limitation of onshore plot space at Port Louis and the requirement of expensive reclamation associated to an onshore LNG terminal, for the purpose of the pre-feasibility design, an FSRU option has been considered forward and adopted as basis for the economic and financial modelling.

There is adequate draft available near shore to berth a 173,000 m^3 FSRU. A single berth for off-loading LNG from LNGC with Ship to Ship Transfer or a dual berth jetty to berth FSRU on one side and LNGC on the other side are both possible. The concept adopted will follow the near shore LNG import Terminal. Some of the LNGC suppliers are reluctant to agree for Ship to Ship transfer. To allow greater flexibility in LNG supply from LNGC a dual Jetty concept has been proposed. The Jetty will have Marine Loading Arms (MLAs) for transfer of LNG from LNGC to jetty and another set of MLAs for transfer from Jetty to FSRU. HP Arm will transfer Regas NG from FSRU to Jetty. The Regas NG will be transferred to On-Shore Receiving Facility (ORF) by sub-sea pipeline. The ORF will broadly have Filter, Pressure Let Down and the metering station. The concept is shown below:

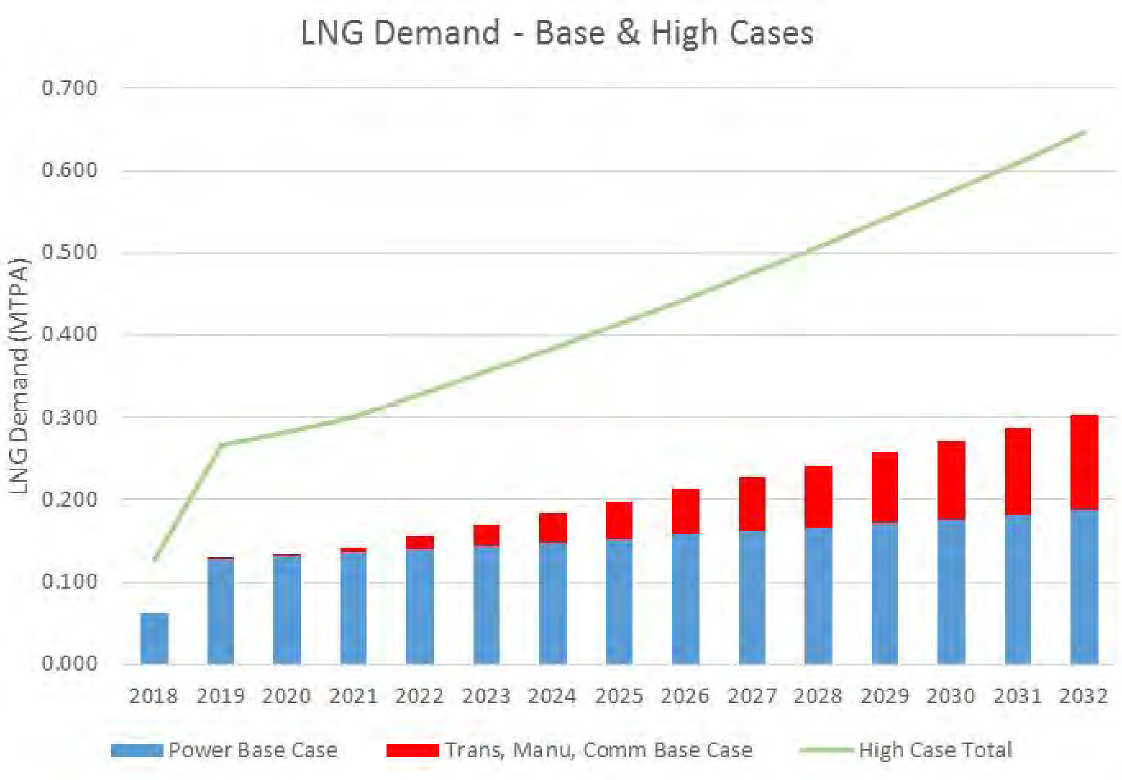
Exhibit 0-18: FSRU with Jetty Structure

LNG Supply Chain

The LNG market is expected to be well supplied with LNG as new liquefaction projects are developed, sanctioned, and constructed to meet growing demand. Consequently, Mauritius should expect to be able to access supplies towards the end of the decade when the construction and commissioning of both the LNG terminal and the new 100 MW power plant are expected to be completed. Most LNG Suppliers tend to have minimum volume thresholds to commit LNG supplies under long-term contracts. This minimum volume threshold varies amongst suppliers, but is usually approximately 0.25 MTPA. The LNG requirements for Mauritius are relatively low under either the

Base Case (new CCGT; conversion of 6 units at Ft. Victoria and 3 units at St. Louis plants; new 4x15MW units at St. Louis; base LNG adoption rate for transportation, industrial and commercial sectors; and base power growth projections) or High Case (new CCGT; conversion of 6 units at Ft. Victoria and 3 units at St. Louis plants; replacement of 5 units at Ft. George, 2 units at Ft. Victoria, and 4 units at St Louis plants; high LNG adoption rate for transportation, industrial and commercial sectors; and high power growth projections) volume scenarios, as shown in the graph below.

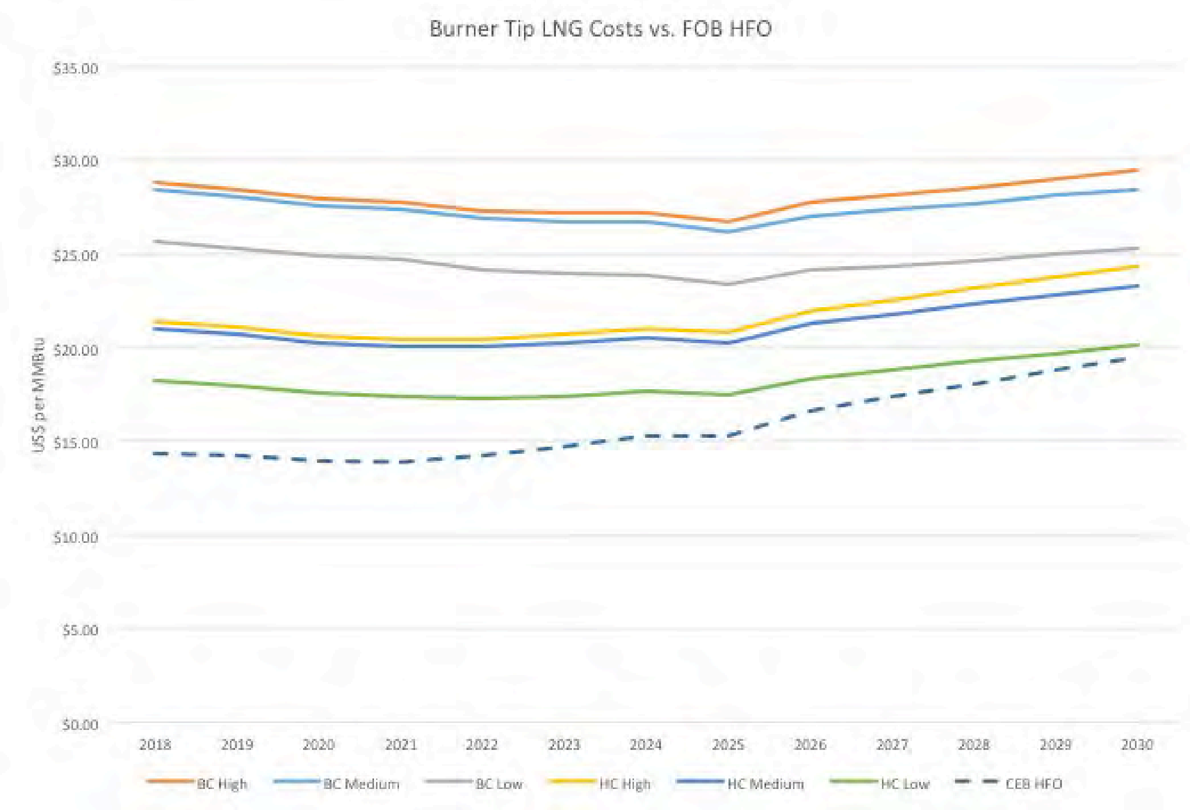
Exhibit 0-19: LNG demand for Base and High Cases



However, Mauritius should still be able to procure LNG in the spot/Short-term market (for the Base Case), and potentially in a long-term contract for the High Case scenario. Because LNG suppliers tend to prefer to control the shipping of LNG and the volumes required are relatively small, LNG will most likely be purchased on a Delivered Ex Ship (DES) basis. This will allocate both the responsibility and the risks to procure and manage LNG shipping capacity to the LNG supplier.

While LNG requirements are relatively low, LNG prices and the cost of the LNG terminal infrastructure are expected to be relatively high. Consequently, it may be challenging to justify the use of LNG in the power sector if the delivered cost of regasified LNG (burner tip cost) is being compared to HFO as the next best fuel alternative. However, as demand grows, the LNG terminal infrastructure costs are spread over larger volumes and the spread between the burner tip cost of LNG and HFO improves over time. The chart below compares the projected LNG prices delivered to the power plants against the projected price of HFO.

Exhibit 0-20: Burner Tip LNG Costs vs. FOB HFO



The price of LNG represents a significant portion of the burner tip cost of LNG and therefore, pricing dynamics in the market will have a significant impact on the affordability of LNG for Mauritius. New potential sources of LNG are being developed in East Africa (Mozambique and Tanzania) and generally not expected to start operations until 2018 at the earliest and more likely 2020 and later. Although that LNG is being targeted to be sold to large creditworthy markets (e.g. Japan) at prevailing global prices to justify the massive capital investments required, some of that output could be sold to smaller regional markets like Mauritius. Pricing for that LNG is most likely to be based on global prices; however, a government-to-government agreement may result in discounted prices, although, to date, there are very few precedents for such discounted government-to-government LNG sales. For this project, the proportion of the burner tip cost that reflects the cost of the LNG infrastructure is very high (30% to 50% of the burner tip cost of LNG is attributed to the LNG infrastructure) because of the relatively low volume requirements. There may be opportunities to explore small scale LNG infrastructure alternatives to reduce the cost of the LNG imports, storage and regasification facilities if and when the regional market develops to support the loading of smaller volumes of LNG in small scale LNG ships, or the deliveries of smaller volumes of LNG from large scale LNG carriers calling on multiple smaller facilities.

Although increasing the volume requirements by promoting the use of regasified LNG in other sectors like transportation, industrial, commercial and LNG bunkering, can, overtime, improve economies of scale, the power sector is critical to serve as the anchor market for LNG as it drives short and medium term demand in Mauritius. If LNG is not economically feasible for the power sector and therefore not used in the power sector, it is very unlikely that LNG can be introduced in other sectors.

Integrated implementation plan & Cost estimate

This section presents a consolidated view on the implementation schedule and CAPEX estimates as provided for the various aspects considered in the study. From the previous sections, the preferred technology options were identified as a Near-shore 173,000m^3 Floating Storage Regasification Unit (FSRU) with a jetty and 1MTPA subsea gas pipeline feeding an Onshore Receiving Facility (ORF) located at the Les Grandes Salines site for LNG import, 2x1 GTCC based on the LM6000 PF for the new 100MW power plant and the conversion of Fort Victoria (6*15MW) and St. Louis (3*13.8MW). Although the gas demand for the planned new 4x15MW units at St. Louis has been included in the Base Case Demand Projection for this study, the CAPEX cost of these units (approx. 3.5Billion MUR) has not been included in the implementation plan or cost estimate as it is thought to be separate from the LNG study and planned to be implemented irrespective of the LNG study findings.

The Implementation plan was prepared for the preferred technology options and the following key highlights are noted (given start date of schedule is the Contract signature of this Pre-feasibility study):

- The Planned Completion date for the Mauritius LNG Project is July 2019. This is a total of 45 months from EPC Award.
- The precursors to EPC award are noted by key activity drivers such as the Environmental Impact Assessment, geotechnical and topographical surveys, which are scheduled for completion in July 2015. Priority must also be given to CEB's decision to proceed to FEED phase which will run for 6 months, with a planned completion date of April 2015. The tender and bid phase including finalization and contractor awards will run for a period of 8 months with the EPC Award scheduled for the December 2015.
- The LNG supply chain phase to conduct market sounding and meet potential LNG suppliers will run for 24 months.
- The phase duration which covers Detailed Engineering, Procurement, Construction and Commissioning are as follows:

LNG Import Facilities	December 2015 to July 2018	32 months
100MW Power Plant	May 2016 to September 2018	29 months

The CAPEX estimate was used as input for the Economic and Financial Modelling. The estimates were developed by utilization of in-house data, Thermoflow PEACE software for the power plant and supplemented by OEM supplied information. The estimate has an expected estimate accuracy <+/-50% (before contingency), requiring a contingency range of 15 – 25%. A Project Contingency factor of 20% has been selected for this estimate.

It has been assumed that the engineering and development of the entire LNG import facility will be implemented under a typical EPC model and the FSRU will be procured under a long-term leasing arrangement requiring no initial capital investment or leasing cash deposits. No dredging is indicated for the selected location of the ship access channel to the jetty and FSRU and normal seabed and ground conditions have been assumed.

For the new power plant and the conversions of old stations, it has been assumed that the feasibility and front-end engineering (FEED) scoping of the project will develop a EPC contract to secure the entire power station development on a progressive LSTK price basis.

For the conversion of the units at Fort Victoria and St. Louis, CAPEX estimate assumes all the modifications will be done in-situ and includes all necessary plant modifications for the conversion, including scope outside of the engines.

General Scope Exclusions include Owner's capital cost, environmental impact assessments, operational spares, first gas product, construction phase MV power supply and utility costs to enable the site works.

The results for the CAPEX estimation are given in summary format in Exhibit 0-21.

Exhibit 0-21: CAPEX estimates summary (rounded to nearest 10,000)

WBS LEVEL 1 (Value- Chain)	WBS LEVEL 2 (Process / Area / Element)	Amount
LNG IMPORT FACILITY		
	JETTY STRUCTURE	$52,421,509
	JETTY TOPSIDES EQUIPMENT	$6,900,000
	JETTY TOPSIDES CONSTRUCTION	$23,184,000
	FSRU (Leased)	$0
	EXPORT GAS PIPELINE	$14,421,509
	ORF EQUIPMENT	$9,000,000
	ORF CONSTRUCTION	$3,001,018
	O&U (Offsites & Utilites)	$22,621,295
POWER PLANTS		
	NEW POWER PLANT (100MW)	$126,990,734
	HFO CONVERSION FT VICTORIA (6x15MW)	$31,500,000
	HFO CONVERSION ST LOUIS (3x13.8MW)	$14,490,000
EPCM		
	FEASIBILITY STUDY - LNG TERMINAL	$989,383
	FEASIBILITY STUDY - NEW 100MW PS	$266,681
	FEASIBILITY STUDY - HFO PS CONVERSIONS	$308,133
	FEED - LNG TERMINAL	$14,289,543

WBS LEVEL 1 (Value- Chain)	WBS LEVEL 2 (Process / Area / Element)	Amount
	FEED - NEW 100MW PS	$1,587,384
	FEED - HFO PS CONVERSIONS	$919,800
	IMPLEMENTATION - LNG	$2,935,000
	IMPLEMENTATION - NEW 100MW PS	$1,593,000
	IMPLEMENTATION - HFO CONVERSION	$1,722,000
OWNERS' COSTS		Excluded
SUBTOTAL (excluding Contingency)		$329,140,988
PROJECT CONTINGENCY @ 20%		$65,828,198
TOTAL CAPEX (including Contingency)		**$394,969,186**

Economic and Financial Modelling

The financial models for the LNG Regasification Terminal and 100MW CCGT Power Plant have been prepared on a limited recourse project finance basis. This approach requires the cashflow of the project to be sufficient to recover the full cost of the investment and a return for the investor. For the purposes of this study it has been assumed that the investor would require a minimum Nominal Internal Rate of Return after tax of 20%, which is considered reasonable for this type of investment. The respective tariffs were therefore calculated to achieve this return. Should the funding model and return assumptions be adjusted it would naturally have an impact on the required tariffs.

The bulk of the cost of these projects, excluding the LNG cost, is of a fixed nature. This has the result that both projects are very sensitive for the throughput or capacity factor assumed.

LNG Regasification Terminal Financial Model Results

In the case of the LNG Regasification Terminal, the minimum practical terminal size results in a facility that is underutilised for the most part during the evaluation lifetime of the project. This results in a regasification tariff that is higher than what would normally be expected from a facility of this nature that is more optimally utilised. As can be seen from Exhibit 0-22 the effective tariff per MMBtu does come down considerably as the throughput volume increase.

Exhibit 0-22: Base Case Capacity Charge

Operating Year	Annual Capacity Fees (USD '000)	Quantity LNG Processed (Ton '000 pa)	Capacity Charge (USD / Ton)	Capacity Charge (USD / Mmbtu)
2018	47 143	61	767	15.76
2019	95 935	127	753	15.46
2020	99 293	132	754	15.48
2021	102 768	135	762	15.66
2022	106 365	139	765	15.70
2023	110 088	143	770	15.81
2024	113 941	147	774	15.88
2025	117 929	151	779	16.00

Operating Year	Annual Capacity Fees (USD '000)	Quantity LNG Processed (Ton '000 pa)	Capacity Charge (USD / Ton)	Capacity Charge (USD / Mmbtu)
2026	122 057	156	784	16.10
2027	126 329	161	787	16.16
2028	130 750	166	788	16.18
2029	135 326	169	801	16.44
2030	140 063	176	794	16.31

Exhibit 0-23 details the main outputs of the sensitivity analysis performed, under which the following scenarios have been modelled:

- Capital cost: ±20%.
- Operating cost: ±20%.
- FSRU lease: USD 140/110 ‘000 per day.
- Interest rate: ±2%.
- Throughput: 35%, 65%, 85% (base = 50%).
- Oil Price: high, low, Henry Hub pricing (HHP).

Exhibit 0-23: Sensitivity of Main Parameters

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Year 1 Production (Ton'000)	Year 1 Cap. Income	Year 1 Tariff (USD/ MMbtu)	Year 15 Tariff
FSRU - Base	179 713	80 405	198 217	126	94 285	15.43	16.80
+20% Capex	215 656	81 071	237 835	126	101 475	16.60	18.09
-20% Capex	143 771	79 740	158 600	126	87 060	14.24	15.52
+20% Opex	179 713	96 486	198 217	126	106 333	17.40	18.95
-20 Opex	179 713	64 324	198 217	126	82 203	13.45	14.65
Interest 2% up	179 713	80 405	200 785	126	95 537	15.63	17.03
Interest 2% down	179 713	80 405	195 641	126	93 060	15.23	16.59
$140k per day Charter cost	179 713	86 274	198 217	126	99 092	16.21	17.66
$110k per day Charter cost	179 713	74 536	198 217	126	89 460	14.64	15.94
Low case 35% load factor	179 713	80 395	198 217	99	94 280	19.52	18.60
High case + 65% load factor	179 713	80 581	198 217	286	94 353	6.77	6.08
High case + 85% load factor	179 713	80 594	198 217	321	94 359	6.03	5.81

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Year 1 Production (Ton'000)	Year 1 Cap. Income	Year 1 Tariff (USD/ MMbtu)	Year 15 Tariff
High Oil price	179 713	80 412	198 217	126	94 288	15.43	16.80
Low Oil price	179 713	80 389	198 217	126	94 278	15.42	16.80
Henry Hub price	179 713	80 375	198 217	126	94 277	15.42	16.80

It is clear that the highest sensitivity is based on the throughput from the terminal. It is however noted that under the higher utilisation scenarios, the market reaches saturation before the plant reaches it full utilisation. Therefore, the processing is constrained to the market's ability to absorb the product processed.

CCGT Power Plant Model Results

The economic case for the Power Plant is equally dependent on the dispatch factor assumed. Based on the regasification tariff required to make an economic case for the Terminal and the assumed LNG delivered cost it would be difficult to justify the cost of power generation from the CCGT Power Plant if it is operated at a base case of 50% dispatch factor. As can be seen from the sensitivity analysis performed in Exhibit 0-25, the economic case improve dramatically when the Power Plant is operated at a dispatch factor of 65% or 85% respectively and a high natural gas growth scenario for the Mauritian market is assumed.

Under the sensitivity analysis the following scenarios have been modelled:

- Capital cost: ±20%.
- Operating cost: ±20%.
- Interest rate: ±2%.
- Throughput: 35%, 65%, 85% (Base = 50%).
- Oil Price: high, low, Henry Hub pricing (HHP).

These results are displayed below. As anticipated, higher oil prices reflect a higher fuel cost and require increased tariff to compensate. This increase could be partially absorbed through economies of scale as reflected in the higher capacity scenarios.

Exhibit 0-24: Base Case - Operating Year 1 Tariff Make Up

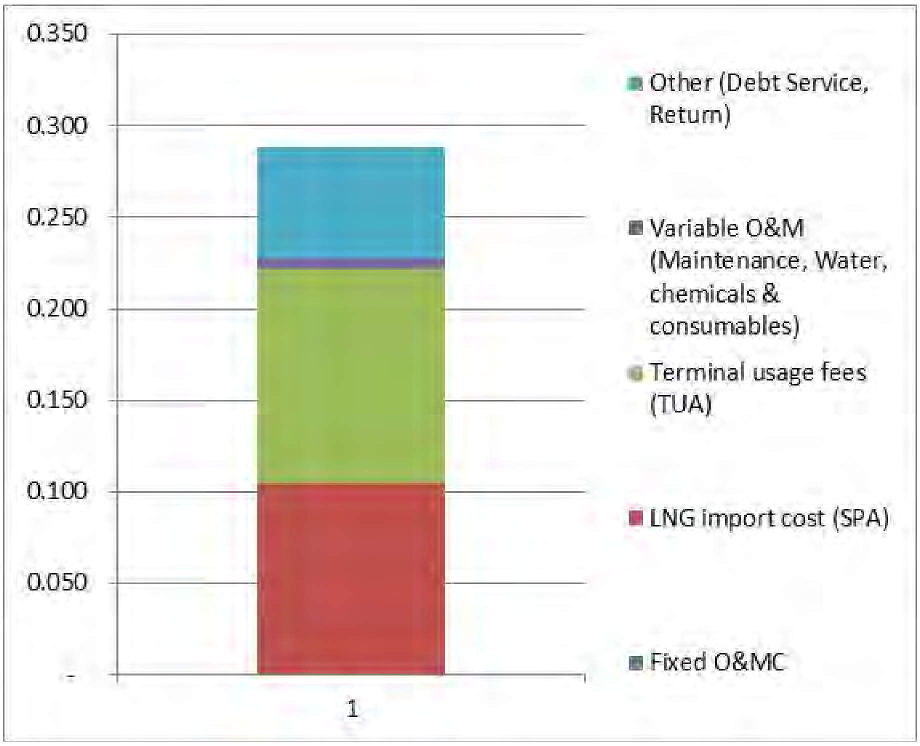


Exhibit 0-25: Power Plant Sensitivity Analysis

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Avg. Generation p.a (MWh)	Equity IRR	Year 1 Tariff (USD/kWh)	Tariff (MUR/kWh)
Base Case	156 523	126 353	177 276	403 488	20.0%	0.29	8.67
+20% Capex	187 828	126 353	212 708	403 488	20.0%	0.30	9.09
-20% Capex	125 219	126 353	141 845	403 488	20.0%	0.27	8.25
+20% Opex	156 523	151 623	177 276	403 488	20.0%	0.33	9.99
-20 Opex	156 523	101 082	177 276	403 488	20.0%	0.24	7.36
Interest 2% up	156 523	126 353	180 906	403 488	20.0%	0.29	8.78
Interest 2% down	156 523	126 353	173 630	403 488	20.0%	0.28	8.57
35% Capacity	156 523	93 547	177 276	282 442	20.0%	0.33	10.06
65% Capacity	156 523	119 155	177 276	524 535	20.0%	0.21	6.36
85% Capacity	156 523	153 315	177 276	685 930	20.0%	0.20	5.87
High Oil price	156 523	130 313	177 276	403 488	20.0%	0.29	8.81
Low Oil price	156 523	115 844	177 276	403 488	20.0%	0.27	8.10
Henry Hub price	156 523	108 891	177 276	403 488	20.0%	0.27	8.12

It is evident that the biggest portion of the tariff is ascribed to the Terminal usage fee and the LNG supply price. Both of these aspects are linked to the very low demand from the sources considered for this study.

Discussion & Recommendations

This pre-feasibility study found that although the import and use of LNG for power generation and transport, commercial and industrial sectors is technically feasible, it would be commercially challenging, in the current conditions. As can be seen from the financial models, the main sensitivity is around the low LNG demand from the sources considered. This leads to underutilization of costly LNG import infrastructure and difficulty in sourcing such low volumes of LNG at the required prices.

Also, when considering the sensitivity of the CAPEX and OPEX projections, or other financial parameters for that matter, it is clear that reducing these inputs may make the use of LNG in Mauritius more attractive, but will not make it a preferred fuel option if not also coupled with an increase in demand.

Although increasing the volume requirements by promoting the use of regasified LNG in other sectors like transportation, industrial, commercial and LNG bunkering, can, overtime, improve economies of scale, the power sector is critical to serve as the anchor market for LNG as it drives short and medium term demand in Mauritius. If LNG is not economically feasible for the power sector and therefore not used in the power sector, it is very unlikely that LNG can be introduced in other sectors.

Aspects that can be considered to increase the economic feasibility of using LNG and can be revisited sometime in the future:

- Reduction in the price at which LNG can be acquired
    - New potential sources of LNG are being developed in East Africa (Mozambique and Tanzania) and generally not expected to start operations until 2018 at the earliest and more likely 2020 and later. Pricing for that LNG is most likely to be based on global prices; however, a government-to-government agreement may result in discounted prices, although, to date, there are very few precedents for such discounted government-to-government LNG sales.
- Increasing the volume requirements and therefore the terminal throughput and lowering the unit fee for the LNG terminal.
    - Increase the capacity factor the CEB thermal stations and/or constructing more LNG fired capacity. This may be possible through revised agreements or retiring of some of the older / inefficient IPP's. For this option to be plausible under the CEB "least cost policy", the sustainable development commitment from CEB has to be motivated through incentives like the Maurice Ile Durable (MID), under the auspices of the environmental and social benefits of using LNG vs coal for instance. Further study would be required to investigate this aspect considering existing PPA agreements, transmission to load, coal supply dynamics, MID funding available etc.
    - Exploring the option of bunkering: Consequently, if the LNG bunkering market gains traction in the Indian Ocean and for routes close to Mauritius, LNG bunkering could serve as another potential market segment to increase LNG throughput and improve

economies of scale. In the near term, bunker volumes would have to be about 0.45 MTPA for the Base Case volume scenario and about 0.3 MTPA for the High Case volume scenario to reach a break-even burner tip price of LNG versus HFO. Further studies would be required to assess the potential LNG bunkering market in Mauritius taking into account bunker demand in the domestic shipping sector, shipping routes and traffic and potential competition from major regional (South Africa) and super regional (Fujairah and Singapore) bunkering hubs.
    - Mauritius could become a LNG hub; however it is uncertain of this will have major impact as there are no major consumers in the vicinity[2]. Maybe if Mauritius worked with Reunion to also put in LNG facilities, then Mauritius could become a hub and Reunion a spoke, they could possibly have enough LNG to share the 1 MTPA capacities in future.
    - An increase in industrialization, specifically of Refining and Petrochemical sector. However, further study would be required to determine the potential and impact on volumes.
- Reducing terminal CAPEX and OPEX costs
    - There may be opportunities to explore small scale LNG infrastructure alternatives in the future when the challenges of available small scale suppliers and carriers have been overcome. These challenges include: There are currently no LNG supply sources able / willing to accommodate and load smaller LNGC's, Potential small scale LNG supply sources being too distant to Mauritius, Lack of application of small LNG carriers for shipment to long distances.

The scope of this study excluded an investigation into the non-financial factors (incl. environmental & social) that can be considered in order to motivate the case for LNG import and use in Mauritius; these could be quantified and included in the financial analysis through further study. If this is of national importance, special government funding and/or tax/investment incentives may be proposed to stimulate market uptake of LNG. Possible aspects to consider could include, but not limited to

- To diversify the energy mix of the country and increase energy security
- Reduction in harmful emissions and related environmental benefits. This can be monetized, amongst others, by possible credits that can be obtained from reducing harmful emissions i.e. CDM mechanism.
- The enhancement of the image of Mauritius as a country and tourist or investment destination due to its positive low carbon policies and the associated benefits to the economy
- The impact on health of the population due to reduced pollution and the associated medical cost savings or reduction in loss of productivity in the workplace.
- The impact of embarking on a national infrastructure drive to implement LNG use in the power and other industries in terms of job creation and other downstream economic benefits.

[2] Rodrigues – there are only 30,000 people on that island compared with 1.3 million on Mauritius and it has a power generation capacity of 11MW, it is 600km from Port Louis. Reunion has a population of 835,000 people and a higher GPD per head than Mauritius, but it is a separate country, French speaking and about 200 km away.- too far for a subsea pipeline.

ABBREVIATIONS & UNITS

FS	Annual Financial Statements
ARO	After receipt of order
BOE	Barrels of Oil Equivalent
BARG	Bar, gauge
BOG	boil off gas
Btu	British thermal unit
CAPEX	capital expenditure
CNG	Compressed Natural Gas
CO2	carbon di-oxide
CO	carbon mono-oxide
CD	Chart Datum
CDM	Clean Development Mechanism
CEB	Central Electricity Board
CER	Certified Emission Reduction unit
CCGT	Combined Cycle Gas Turbine
CC	combined cycle
ºC	degrees Celsius
DC	Direct Current
DSCR	Debt Service Cover Ratio
DBM	Disconnectable buoy mooring
DAT	Delivered at Terminal
DES	Delivered Ex-Ship
DF	duct firing
EA, ea	each
DWT	Deadweight tonnage
EPC	engineer, procure and construct
EPCM	engineer, procure and construction management
EN	Euro Norms
EUR	Euro
ERU	Emissions Reduction Unit
FSRU	Floating storage regasification unit
FSU	Floating Storage Unit
FOB	Freight on Board
GT	gas turbine
GTCC	Gas turbine combined cycle
GA	general arrangement
GBS	Gravity based structure
HFO	Heavy Fuel Oil
HRSG	heat recovery steam generator
Hz	Hertz, (frequency, cycles per sec.)
HP	high pressure / Horse Power
HHV	higher heating value
HHP	Henry Hub Pricing
H, Hr	hour
HTF	High Temperature Fluid
I&C	instrument and controls
ICE	Internal Combustion Engine
IFAAV	Intermediate Fluid Ambient Air Vaporizer
IFV	Intermediate Fluid Vaporizer
IGC	The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk
IMO	International Maritime Organization
IP	intermediate pressure
ISO	International Organization for Standardization
IOC	International Oil Company
JCC	Japanese Custom Clearing price
JV	Joint Venture
JKM	Japan Korea Marker
kg	kilograms
kJ	kilojoules
km	kilometer
kW	kilowatt
kWh	kilowatt hour
LCOE	Levelized cost of electricity
LDC	Least Developed Country
LFO	Light Fuel Oil
LNG	liquefied natural gas
l	liter
LNGC	LNG carrier
LHV	low heating value
LP	low pressure
LV	low voltage
Max.	maximum
mCD	Meters composite depth
MDF	Marine Diesel Fuel

MEZ	Maritime Exclusion Zone
MLA	Marine Loading Arm
MSL	mean sea level
MV	medium voltage
MW	megawatt
MWh	megawatt-hour
MUR	Mauritian Rupees
m	meters
t, tonne	metric ton (1000 kg)
mg	milligram
mm	millimeter
MMBtu	million British thermal units
MMUSD	Million US Dollars
Min.	minimum
M.H.W S.	Mean high water spring
M.H.W. N.	Mean high water neap
M.L.W.N	Mean low water spring
M.L.W.S	Mean Low water neap
MTPA	Million tons per annum
NG	natural gas
NGV	Natural Gas Vehicle
NM	nautical miles
NOx	nitric oxides
Nm³	normal (1 atm, 0C) cubic meter
NA	not applicable, not available
NTP	notice to proceed
NOC	National oil company
NWE	Northwest Europe marker
OCIMF	Oil Companies International Marine Forum
OCGT	Open Cycle Gas Turbine
OPEX	operating expenditure
OEM	original equipment manufacturer
O&M	operation and maintenance
ORF	Onshore Receiving Facility
OSRT	Onshore Storage and Receiving Terminal
O2	oxygen
PEACE	Plant Engineering and Cost Estimating (Thermoflow software)
PCHE	Printed Circuit Heat Exchanger
PHE	Plate Heat Exchanger
ppm	parts per million
PIANC	Permanent International Association of Navigation Congresses
psig	pounds per square inch, gauge
PPA	Power Purchase Agreement
QRH	Quick release hook
ROM	Recommendations for Maritime Works
RO	reverse osmosis
RPM	revolution per minute
SM³	standard cubic meters at the reference condition of 1 bar and 60°F (15.5°C)
QRA	Quantitative Risk Assessment
SPM	single point mooring
SIGTTO	Society of International Gas Tanker and Terminal Operators
ST(G)	steam turbine (generator)
S	Sulphur content of fuel
SO2	sulphur dioxide
SF	supplemental firing
SPA	Sale and Purchase Agreement
SWE	Southwest Europe marker
STV	Shell and Tube Vaporizer
SZ	Safety Zone
TBD	To be Determined
TPA	tonnes per annum
TG	turbo-generator, (turbine-generator)
US	United States
USD	United States Dollar
USGC	United States Gulf Coast (cost basis)
VAT	value added tax
V	volts
Wh	Watt hour
y, yr	year

1. POWER SECTOR ASSESSMENT

1.1 Introduction

In support of CEB's objective of using LNG in their power sector, WorleyParsons evaluated the following two sectors:

a) Conversion of the existing oil fired power plants
b) Proposed 100 MW generation capacity additions

This following sections elaborate WorleyParsons assessment of LNG use in the above two sectors.

1.2 Conversion of Current CEB Power Plants to LNG

The CEB has four thermal Power Stations on Mauritius, which are supplemented by hydroelectric Power Plants and IPP thermal plants. The prime mover, primary fuel, annual load factor and service duty of each CEB thermal power plant is presented in Exhibit 1-1. The primary OEMs are Wärtsilä and MAN either by virtue of their original design or due to acquisition. The feasibility of converting the existing units to using LNG is considered in the following subsections for each of the four (4) power stations.

Exhibit 1-1: Existing CEB Thermal Plant Prime Mover, Fuel, and Service Duty

Plant	Prime Mover	Primary Fuel	Effective Cap. (MW)	Annual Load Factor[1] (%)	Service	References & Note
Ft George	Diesel Engines	HFO 380 cSt (heated)	134	55%	Base loaded	[1]
Ft Victoria	Diesel Engines	HFO 180 cSt	107	35%	Daily Start Stop (Semi Base)	[1], start/stop: ~ MAN & Wartsila generating sets MAN – cannot be operated during night (21;00 to 07:00) due to environmental constraints.
St Louis	Diesel Engines	HFO 180 cSt	71.4	30%	Daily Start Stop (Semi Base)	[1], start/stop: Pielstick & Wartsila generating sets Pilestick cannot be operated during night (21;00 to 07:00) due to environmental constraints
Nicolay	Gas Turbines	Jet A1 (kerosene)	74	3%	Daily Start Stop (Peaking and emergency)	[1], start/stop

Note 1: Annual Load Factor per Integrated Electric Plan Forecast, 2013-2022 [3]

1.2.1 Generic Diesel Engine Conversion Considerations

The conversion of an existing diesel engine based power plant from heavy fuel oil to natural gas (or regasified LNG) involves many design considerations. A central issue determining the feasibility of the conversion involves the convertibility of the prime mover itself. (i.e. conversion of the diesel engine)

For example, should a plant based on the Wärtsilä V46 Engines be converted from fuel oil to dual fuel engines (Natural Gas and Fuel oil), they would need to be converted to Wärtsilä V50 DF engines. In this conversion, the engine parts listed in Exhibit 1-2 would need to be replaced or modified.

Exhibit 1-2: Diesel Engine Parts to be replaced/ modified for HFO to LNG Conversion

Wärtsilä 46 to Wärtsilä 50DF	Replacement/Modification
• New cylinder head and cylinder head equipment	x
• New pistons and piston ring sets	x
• New cylinder liners	x
• Machining of engine block	x
• New camshaft pieces	x
• New turbochargers (or modification if possible)	x
• Exhaust wastegate system (air/fuel ratio control)	x
• Gas fuel system	x
• Pilot fuel system	x
• Engine control system	x

Ref: [2]

In view of the significant number of engine design changes, the feasibility of the engine conversion is effectively determined by the availability of a conversion kit from the Diesel Engine OEM. As such, WorleyParsons has been in communication with the diesel engine OEMs for the specific models installed at the CEB sites to determine whether such conversions are feasible. The results of this communication are presented in the following subsection for each CEB thermal power station along with some high level plant information.

1.2.2 Fort George Power Station

The key details of the existing Fort George generating units are presented in Exhibit 1-3. The primary fuel is heated 380 cSt HFO. The anticipated annual plant load factor is 55% per the IEP for 2013-2022. [3]

Exhibit 1-3: Ft George Power Station Generating Units

Parameter	G1	G2	G3	G4	G5
Technology	ICE	ICE	ICE	ICE	ICE
Make	Sulzer	Sulzer	Mitsui MAN B&W	Hyundai MAN B&W	Hyundai MAN B&W
Model	9RTA76	9RTA76	9K80MC-S	9K80MC-S	9K80MC-S
Cycle	2 Stroke	2 Stroke	2 Stroke	2 Stroke	2 Stroke
Rated Capacity (MW)	24	24	30	30	30
Effective Capacity (MW)	22	22	30	30	30
Year Commissioned	1992	1993	1997	1999	2000
Fuel, primary	380 cSt HFO	380 cSt HFO	380 cSt HFO	380 cSt HFO	380 cSt HFO
Heat Rate (MJ/kWh)	7.88	7.88	7.78	7.42	7.42
Fuel Pressure at Engine Inlet, (Bars)	13	13	8	8	8
Fuel Oil Temperature at Engine inlet, (°C)	130	130	130	130	130
Runtime since commissioning up to 2013-10-31, (hours)	145,277	144,665	122,297	101,769	98,604
Generation since commission up to 2013-10-31 (GWh)	2486.9	2415.1	2583.6	2190	2153.5

Reference: [3,4]

In 1997 New Sulzer Diesel became part of Wärtsilä [5]. WorleyParsons contacted Wärtsilä and learned that no conversion kits are available for allowing the Sulzer units to be able to fire natural gas.

Likewise, MAN Diesel informed WorleyParsons that there are no conversion kits for the Man units installed at Ft George G3-G5 [6].

As such, conversion of the Ft George Power Station is not feasible as no OEM conversion kits are available.

1.2.3 Fort Victoria Power Station

The Ft Victoria Power Station generating unit information is presented in Exhibit 1-4.

Exhibit 1-4: Fort Victoria Power Station Generating Units

Parameter	G1	G2	G3	G4	G5	G6	G11	G12
Technology	ICE	ICE	ICE	ICE	ICE	ICE	ICE	ICE
Make	Wärtsilä	Wärtsilä	Wärtsilä	Wärtsilä	Wärtsilä	Wärtsilä	MAN	MAN
Model	16V46	16V46	16V46	16V46	16V46	16V46	8L58/64	8L58/64
Rated Capacity (MW)	15	15	15	15	15	15	9.8	9.8
Effective Capacity (MW)	15	15	15	15	15	15	8.5	8.5
Year Commissioned	2010	2010	2012	2012	2012	2012	1989	1989
Fuel, primary	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO
Fuel, secondary	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Heat Rate (gm/kWh)	202.6	202.6	202.6	202.6	202.6	202.6	215	215
Heat Rate (MJ/kWh)	8.224	8.224	8.224	8.224	8.224	8.224	8.727	8.727

Reference: [3, 7]. Units that are convertible to allow natural gas firing are shaded in light green.

The existing Fort Victoria Wärtsilä units are dual fuel capable.

Presently the Wärtsilä units are dispatched at 12 MW, but no less than 10 MW for efficiency reasons. The Wärtsilä units can be operated at night, while the MAN units are typically started in the morning (0700) and turned off at night (21:00).[1]The anticipated annual plant load factor is 35% per the IEP for 2013-2022. [3]

Conversion

MAN Diesel informed WorleyParsons that there are no conversion kits for the Man units installed at Ft Victoria G11 and G12 for converting the units to fire natural gas. [6]

Wärtsilä is able to offer conversion of the six (6) 16V46 to 16V50SG for gas only operation or to 16V50DF for tri-fuel (gas, LFO, and HFO) operation. In light of the existing oil infrastructure, CEB may wish to consider implementing the DF option for enhanced fuel reliability should CEB choose to convert the units. The DF engine can be run in either gas or diesel operating mode. The operating mode can be changed while the engine is running, within certain guidelines. If the gas supply should be interrupted, the engine will automatically transfer to the diesel mode operation on marine diesel fuel (MDF) before transferring gradually to HFO over a period of about 1 hour. In the gas mode, the gas (main fuel) is ignited by a pilot MDF fuel. The DF engine requires MDF as a pilot fuel in addition to the fuel oil. According to Wartsila 50DF product guide, the pilot fuel must be in accordance with ISO-F-DMX, -DMA or –DMB. The DF engine always utilizes the MDF pilot fuel injection, no matter whether it is in the gas or diesel mode[3]. The DF engine would require CEB to receive, store and feed MDF for dual fuel operation. Should the CEB not wish to add MDF to their operations, they may convert the existing engines directly to a natural gas fueled spark ignited (i.e., Wartsila SG) engine. The SG engine does not require the MDF pilot fuel, as ignition is provided by the spark. The SG is a single fuel engine and requires NG to operate.

The DF or SG conversion would be performed completely onsite. The conversion is typically performed on two units at a time, with the conversion of each pair taking approximately 2 months following a 6-7 month lead time for the required parts to be manufactured and delivered to site. Thus the conversion of the three (3) pairs at Ft Victoria would take approximately 6 months following the receipt of the parts. Wärtsilä indicates that the performance of the converted unit will be close to that of a new DF unit. The anticipated performance for the converted units is presented in Exhibit 1-5.

Exhibit 1-5: Wärtsilä Engine Conversion Information for the 16V46 to 16V50DF

Parameter	Unit	16V50DF Gas Mode	16V50DF Oil Mode	Notes
Generation	kWe	15,200	15,200	Net of engine driven pumps
Fuel Consumption				
Total Energy Cons. (100% Load)	kJ/kWh	7,300	-	LHV, engine only
Fuel Gas Cons. (100% Load)	kJ/kWh	7,258		LHV, engine only
Fuel Oil Cons. (100% Load)	g/kWh	1.0	189	Note 1

Reference: [8, Data for 500 rpm, 50Hz electric generation mode, and ISO 3046/1]

Note 1. Wartsila provided the pilot fuel oil consumption in units of g/kWh, as the kJ/kWh consumption of the pilot fuel will vary with the heating value. For MDF with an LHV of 42 MJ/kg, the fuel consumption of 1 g/kwh is equivalent to 42 kJ/kWh (LHV). For HFO 180 with an LHV of 41 MJ/kg, the fuel consumption of 189 g/kWh is 7750 kJ/kWh (LHV). The pilot fuel is less than 1% of the fuel heat input.

The approximate cost of the conversion for all parts and labour is estimated as \$350/kW[4] (250 Euro/kW) based on 1st qtr 2014 estimate. All modifications will be performed in situ and does not require sending components back to the factory. This conversion cost includes all necessary plant modifications for the conversion, including scope outside of the engines such as addition of gas meter & regulator, gas piping from metering station to the termination point near the engines, vent rupture disks, exhaust gas ventilating units, and modification of electrical and control systems. This excludes the cost of bringing the natural gas to the site, preparation of the EIA and permitting activities. The NG pressure requirement is low pressure at approximately 75 psig (5 barg). These costs are summarized within Exhibit 1-6.

[3] MDF is required in gas model as a pilot fuel. In the diesel mode, the MDF pilot fuel is required in order to keep the pilot fuel injectors clean. The potential use of an alternate pilot fuel instead of MDF, such as LFO, must be validated by the engine OEM.

[4] The cost of conversion is based on work performed on the African continent. Conversion between USD and Euros was based on an exchange rate of 1.37 USD to Euro.

Exhibit 1-6: Wärtsilä Engine Conversion Cost Information for the 16V46 to 16V50DF

Parameter	Unit	16V50DF Gas Mode	Notes
Engine Conversion	$/kW	350	All parts and labor, as described above. Based on 1st qtr 2014 estimate
Non Fuel Variable O&M Cost First 48,000 operating hours Thereafter	 $/MWh $/MWh	 0.7* 1.4*	* this amount less than the non-fuel VO&M on HFO. (i.e., the provided value is the incremental reduction in the VO&M for the Gas mode compared to the HFO mode.)

Reference: [2]

Following the conversion, the environmental performance will improve as illustrated in Exhibit 1-7.

Exhibit 1-7: Wärtsilä Engine Conversion Emission Benefits

Parameter	Unit	Typical HFO	Typical Gas	Notes
NOx Emissions	mg/m3	2000	375	
SOx Emissions	mg/m3	5300	15	For 3% fuel sulfur
Particulate emissions	mg/m3	50	10	

Reference: [9]

In addition to improved emissions, the converted Engines will have the following benefits/features [9]:

- Same State-of-Art design as New DF engines
  - Latest controls & software,
  - Main engine components, and
  - Gas /fuel injection.
- Maintenance benefits:
  - Engine running hours reset to zero after conversion,
  - Component lifetime is extended,
  - Maintenance cost of plant decreases by ~ 1euro/MWh.
- Fuel Flexibility (LFO, HFO, and natural gas)

In addition to the engine conversion, the plant conversion will include the following [9]:

- Addition of gas regulating unit (for pressure and flow control), controlled by the plant automation system.
- Addition of pilot fuel system, with pilot fuel pump and new injectors combining the main fuel oil and pilot fuel.
  - The high pressure fuel pipe for the pilot fuel (MDF) are double walled for safety.
  - Safety valve and pressure sensors are added.
- Addition of explosion vent rupture disks into the existing exhaust gas system in case of unburned exhaust gas explosion. Typically 2-3 explosion vents are added per generating set.
- Addition of exhaust gas ventilating units to purge exhaust gas pipe. Ventilating units are operated in 5-10 minute sequence when gen-sets are stopped as part of safety concept.
- Modification of the cooling water system to account for the modifications of the charge air system and the more accurate temperature control requirements.
- Modification to the electrical and automation system

- LV switchgear modifications (e.g., new exhaust gas ventilation fan)
- DC panel addition for 24 VDC engine control system
- Upgrade control panels to latest PLC for engine and common control
- New operating stations.

Highlights of the operating mode flexibility in both the gas and diesel mode are presented below [9].

- Gas Operating Mode (i.e., running on gas with MDF pilot fuel)
  - Instant transfer to MDF at any load, without loss of power or speed.
    - Can be manually requested
    - Can be automatic transfer following alarm (e.g., > 5 min below 10% load on gas)
  - Gradual transfer from MDF to HFO at any load takes about 1 hour.
- Diesel Operating Mode (i.e., running on HFO, or MDF with MDF pilot fuel)
  - Gradual Transfer from HFO to MDF at any load takes about 1 hour
  - Transfer from MDF to Gas at loads <80% MCR duration about 2 minutes, without loss of engine power or speed.

Wärtsilä has converted approximately twelve (12) V46 HFO engines to V50DF engines since 2006 [9].

1.2.4 Saint Louis Power Station

The St Louis Power Station generating unit information is presented in Exhibit 1-8.

Exhibit 1-8: Saint Louis Power Station Generating Units

Parameter	G1	G2	G3	G4	G5	G7	G8	G9
Technology	ICE	ICE	ICE	ICE	ICE	ICE	ICE	ICE
Make	Pielstick	Pielstick	Pielstick	Pielstick	Pielstick	Wärtsilä	Wärtsilä	Wärtsilä
Model	18PC3V	18PC3 V	18PC3V	18PC3V	18PC3V	16V46	16V46	16V46
Rated Capacity (MW)	11.9	11.9	11.9	11.9	11.9	13.8	13.8	13.8
Effective Cap (MW)	6	6	6	6	6	13.8	13.8	13.8
Yr Commissioned	1978	1978	1979	1979	1981	2006	2006	2006
Fuel, primary	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO
Fuel, secondary	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Heat Rate (MJ/kWh)	9.34	9.34	9.34	9.34	9.34	8.2	8.2	8.2
Cooling Scheme	Cooling tower	Cooling tower	Cooling tower	Cooling tower	Cooling tower	Air cooled radiators	Air cooled radiators	Air cooled radiators

Reference: [3,10]. Units that are convertible to allow natural gas firing are shaded in light green.

The G6 Pielstick unit was retired in July 2012 [10]. The old Pielstick Power House (units G5 and G6) will be demolished. A new power house shall be constructed to house 4 new 15 MW dual fuel units

(LNG and HFO 180 cSt) medium speed diesel engines in 2016 [1]. In 2006, MAN Diesel fully acquired the French diesel engine manufacturer S.E.M.T. Pielstick SA. The anticipated annual plant load factor is 30% per the IEP for 2013-2022. [3]

The potential conversion of the above units is discussed below.

Conversion

MAN Diesel informed WorleyParsons that there are no conversion kits for the Pielstick units installed at the Saint Louis Power Station. [6] The Pielstick units are 33 to 36 years old and are being planned for retirement. Four 15MW units are planned for installation at St Louis. CEB could consider the installation of gas fired units for this new installation.

Wärtsilä is able to offer conversion of the three 16V46 into 16V50SG for gas only operation or 16V50DF for tri-fuel (gas, LFO, and HFO) operation. In light of the existing oil infrastructure, it is recommended that CEB consider implementation of the DF option for enhanced fuel reliability should CEB choose to convert the units.

Since the Wärtsilä units at Saint Louis Power station are the V46 model just like at Ft Victoria, the reader is referred to the Ft Victoria section for additional conversion information.

The conversion would be performed completely onsite. The conversion is typically performed on two units at a time, with the conversion of each pair taking approximately 2 months following a 6-7 month lead time for the required parts manufactured and delivered to site. Thus the conversion of the 3 units would take approximately 4 months following the receipt of the parts, assuming the conversion is performed as one pair and one singleton.

The performance of the converted engines can be found in Exhibit 1-5, except that the converted capacity is expected to be limited to the current rated capacity of 13.8MW.

The approximate cost of the unit conversion is summarized within Exhibit 1-9. All modifications will be performed in situ and does not require sending components back to the factory. This conversion cost includes all necessary plant modifications for the conversion, including scope outside of the engines such as addition of gas meter & regulator, gas piping from metering station to the termination point near the engines, vent rupture disks, exhaust gas ventilating units, and modification of electrical and control systems. This excludes the cost of bringing the natural gas to the site, preparation of the EIA and permitting activities.

Exhibit 1-9: Wärtsilä Engine Conversion Cost Information for the 16V46 to 16V50DF

Parameter	Unit	16V50DF Gas Mode	Notes
Engine Conversion	$/kW	350	All parts and labor, as described above. Based on 1st qtr 2014 estimate.
Non Fuel Variable O&M Cost First 48,000 operating hours Thereafter	 $/MWh $/MWh	 0.7* 1.4*	 * this amount less than the non-fuel VO&M on HFO.

Reference: [2]

Following the conversion, the environmental performance will improve as illustrated in Exhibit 1-7.

1.2.5 Nicolay Power Station

The Nicolay Power Station generating unit information is presented in Exhibit 1-10.

Exhibit 1-10: Nicolay Power Station Generating Units

Parameter	G1	G2	G3
Technology	GT	GT	GT
Make	GE (Alsthom)	GE (GEC Alsthom)	GE (European GT)
Model	Frame 5 (MS-5001-P)	Frame 5 (MS-5001-PA)	Frame 6B (MS-6541-B)
Cycle	Open	Open	Open
Rated Capacity (MW)	21.8	22.7	33.9
Effective Capacity (MW)	21	21	32
Yr Commissioned	1988	1991	1995
Fuel	Jet A1	Jet A1	Jet A1
Heat Rate, Design (kJ/kWh)	13,020	12,847	11,500
Effective Efficiency, 2013 (%)	25.70%	26.20%	28.60%

Reference: [3, 11]

The conversion of the Nicolay Power Station generating units from Jet A1 to LNG may not prove to be desirable for the following reasons:

- The Nicolay units are simple cycle peaking units. According to the Integrated Electricity Plan, the anticipated annual plant load factor of these units is only about 3%. [3]. Thus converting the Nicolay units to LNG would contribute very little towards reaching the critical mass of the LNG consumed and is not expected to be cost effective due to such a low capacity factor[5] and in light of the cost of connecting the plant to the LNG source and cost converting the units to LNG.
- Conversion of the diesel engine plants from HFO to LNG as opposed to from Jet A1 will have the biggest positive impact on the environment.

Based on the 3% annual load factor, WorleyParsons would not recommend the conversion of these units to LNG.

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[5] If the Nicolay GT are converted to LNG, the simple cycle heat rate (circa 11.5 to 13.0 MJ/kWh) will remain higher than that of the reciprocating engines (circa 7.2 to 9.3 MJ/kWh), thus the plant utilization would not be expected to increase significantly. Thus, if the Nicolay units are converted to gas, the LNG utilization will not substantially increase.

Converting the Nicolay units to a combined cycle plant would require a dedicated study of the unique attributes of this plant as it relates to conversion; nevertheless, the site does not appear to have any room for the addition of HRSGs, STGs and balance of plant equipment. If a conversion were entertained then the overall CEB LNG utilization would not increase because the generation of the new 100 MW plant or some other unit would have to decrease because there is not a change to the overall demand. For these reasons, the current utilization factor is expected to remain unchanged and WorleyParsons does not recommend Nicolay for LNG conversion.

Nevertheless, WorleyParsons has determined that a conversion is feasible and has an estimated cost of conversion as presented in Exhibit 1-11. This excludes the cost of bringing the natural gas to the site. The conversion would be expected to require an outage of approximately 2-3 months.

Exhibit 1-11: Nicolay Power Station GT Conversion

Parameter	Units	G1	G2	G3
Make		GE (Alsthom)	GE (GEC Alsthom)	GE (European GT)
Model		Frame 5 (MS-5001-P)	Frame 5 (MS-5001-PA)	Frame 6B (MS-6541-B)
Conversion Cost (USD, 2014)	$/kW	90	90	90
Conversion Cost (USD, 2014)	Million $	1.9	1.9	2.9

Should the Nicolay Power Station GT be modified, it is assumed that the combustion turbine system will be modified to have a dual fuel capability of burning either natural gas (primary fuel) or Jet A1 (backup fuel). The existing Jet A1 storage / transfer and handling equipment would be retained as back-up. The natural gas would be delivered to the property at pressure so a gas compressor will not be needed. Each machine would be provided with a prefabricated gas fuel skid including filter, fuel controls, stop valves, and instrumentation and control interface panel. A regulating and metering station will be provided at that site for controlling pressure and measuring flow.

The generation capacity and heat rate would not be significantly altered by the fuel conversion. The conversion to natural gas is expected to increase the capacity by approximately 2.5% and reduce (improve) the heat rate by approximately 1.4% compared to oil firing[6]. Therefore the change in overall fuel consumption at full load would be an increase of approximately 1.2%[7].

1.2.6 Existing Units that cannot be Converted

As discussed above, several of the existing diesel gensets cannot be converted from fuel oil firing to natural gas firing. In order to maximize the LNG consumption to reach a critical consumption level, CEB could consider the installation of new units to replace the unconvertible units. The replacement capacity could be either a large centralized plant(s) like the Les Grandes Salines plant, or could be replacement of reciprocating engines or combustion turbines. The evaluation of the best alternative for the units that cannot be converted could be part of a follow-on feasibility study.

Should CEB wish to continue with reciprocating engines capable of firing natural gas, it is estimated that the EPC cost $1100/kW to $1400/kW depending upon whether a gas only or dual fuel unit was desired. A gas only unit would be towards the lower side of the range, while a dual fuel unit would be

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[6] The power output will increase and the heat rate will reduce with gas firing as the firing temperature will be allowed to rise compared to oil firing case.

[7] The fuel consumption can be calculated by the (Output) * (Heat Rate). The MW output increase of 2.5%, and the heat rate improvement of 1.4%, combine to yield a fuel consumption increase of approximately 1.2%. Thus (1+.025)*(1 - 0.014) = 1.011, or 1.1%. This is slightly different than the quoted 1.2% because of round off.

towards the higher side of the range. This does not include the reuse of any equipment. For the purposes of evaluating the critical mass of the LNG assumed, the gas only reciprocating engines have been assumed.

1.2.7 Discussion and Recommendations

The potential conversion of the existing CEB power plants to LNG has been discussed in the preceding sections. Exhibit 1-12 summarizes the potential conversions.

Exhibit 1-12: Estimated LNG Consumption from CEB Power Plants

Plant	Convertible Units	Capacity of Converted Units (MW)	Notes
Ft George	None	0	
Ft Victoria	G1-G6	90	6*15MW
St Louis	G7-9	41	3*13.8MW
Nicolay	G1-G3	74	Not recommended for conversion
CEB Plants		**205**	**131 MW w/o Nicolay**

The quantity of LNG that can be consumed by the converted units is presented in Section 1.4.

1.3 New 100MW LNG Power Plant

Based on the discussions at the Kick Off meeting with CEB, it was agreed that the following technologies will be considered for the 100 MW generation capacity additions to capture the impact of the relatively low capacity factor seen by the CEB thermal units.

1. Aero-derivative Gas Turbines based combined cycle project
2. Industrial Gas Turbines based combined cycle project
3. A multiple reciprocating engines project (with distillate combustion support during LNG firing)

The prime mover capacity shall not exceed 50 MW in any of the above technologies.

An additional new plant criteria is that any new plant site would need to be 500 m from the coastline, and 1 km from residential area. Although the 1 km exclusion zone is not a rigid rule, and a smaller exclusion zone can be applied for if required. [12]

1.3.1 Technology & Configuration Options

In order to evaluate the three options, the following analysis elements have been developed:

- Preliminary heat balances / performance data for the above three technology
- Cost estimates for each of the above options
- A table identifying salient prime mover (e.g. gas turbine, gas engine) attributes, overall plant performance, annual utility consumptions and generation, Capex, Opex and such parameters in support of the screening analysis.
- Screening analysis of options with recommendations for the optimum configuration based on the lowest life cycle cost.

The baseline assumptions for this analysis are documented in the Design Basis Document found in Appendix 2.

A screening matrix of candidate gas turbines is presented in Exhibit 1-13. The list includes commercially available gas turbines for a 50 Hz application in the size range of 20 to 50 MW. The presented turbines are grouped into industrial and aeroderivative gas turbine types. The capacity and simple and combined cycle efficiencies of these candidate gas turbines are presented graphically in Exhibit 1-14. The gas turbines selected for further screening will have the most efficient combined cycles from the industrial and aeroderivative gas turbine categories.

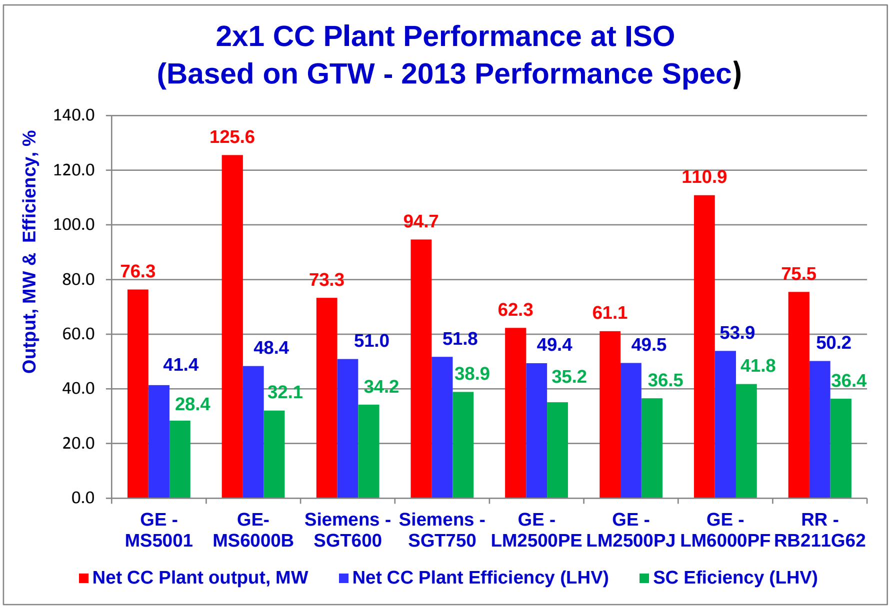
Exhibit 1-13: Candidate Gas Turbine (20 to 50 MW) – Salient Attributes

Blue: Better, Red: Poor

Item	Description	Unit	Industrial				Aeroderivative			
1	Make		GE	GE	Siemens	Siemens	GE	GE	GE	Rolls Royce
2	Model		MS 5001	MS 6000B	SGT600	SGT 750	LM 2500 PE	LM 2500 PJ	LM 6000 PF	RB 211 G62
3	Year Introduced		1987	1978	1981	2012	1981	1981	2006	1993
4	Exhaust Orientation		Top/Side	Top/Side	Top/Side	Top/Side	Top/Side	Top/Side	Axial	Top/Side
5	Is Dry Low NOx Combustor Available		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
6	Gas Turbine Gross Output	kW	26,830	42,100	24,770	35,930	23,090	21,846	42,732	27,216
7	Gas Turbine HR, LHV	kJ/kWh	12,674	11,219	10,524	9,261	10,242	9,850	8,614	9,894
8	Simple Cycle Efficiency, LHV	%	28.4%	32.1%	34.2%	38.9%	35.2%	36.5%	41.8%	36.4%
9	Gas Turbine Exhaust Flow	Tonne/hr	451	508	290	408	257	247	449	329
10	Gas Turbine Exhaust Temperature	°C	483	547	543	462	517	535	451	501
11	2x1 CC Net Output at ISO,	kW	76,330	125,570	73,280	94,700	62,294	61,118	110,870	75,450
12	2x1 CC Net Heat Rate at ISO - LHV	kJ/kWh	8,691	7,438	7,064	6,956	7,282	7,274	6,680	7,168
13	2x1 CC Net Eff at ISO - LHV	%	41.4%	48.4%	51.0%	51.8%	49.4%	49.5%	53.9%	50.2%
14	STG Size in 2x1 Configuration	kW	27,100	44,455	26,450	26,020	18,960	18,830	27,540	24,100
15	CO2 Emission Intensity in CC Mode	kg/MWh	485.2	415.3	394.4	388.4	406.6	406.1	373.0	400.2

Notes:
1. Based on Gas Turbine World 2013 Performance Specification document.
2. Gas Turbine and CC Plant performance are based on gas fuel, new and clean and are at ISO (15C, 60% RH, Sea level) Conditions.
3. CO2 intensity is based on 50.3 gm/GJ - HHV (55.83 gm/GJ- LHV) with gas firing.

Exhibit 1-14: Candidate Gas Turbine (20 to 50 MW) – Capacity and Efficiency



Based on the limitation that the prime mover generation capacity shall not exceed 50 MW in any of the above technologies, along with the improving specific cost of capacity, and efficiency with increasing size, the following gas turbines have been selected for analysis. The turbines selected for more detailed analysis have been highlighted with a light green background and are listed below.

- Aero-derivative Gas Turbine: GE LM 6000 PF
- Industrial Gas Turbine: Siemens SGT 750

As can be seen, the selected gas turbine combined cycles have the best heat rate within both the industrial and aeroderivative gas turbine types. Gas turbines are available in discrete models and it is not possible to perfectly match the 100 MW capacity target. In this sense, the 100 MW target has been considered as a nominal target and that candidate gas turbine combined cycle options that are within 10 to 15% of the target will be considered to have met the nominal target. There are some design elements that can be used to influence the generating capacity, such as the addition of duct firing in the heat recovery steam generator, or the addition of chillers for air inlet cooling. Both of these design features will increase the generating capacity but at the cost of additional capital and a worsened heat rate. Thus, at this stage, these options have not been considered.

Large medium speed reciprocating engines are the appropriate candidate for the reciprocating engines. Slow speed engines are expensive and require significantly more real estate, making them uncompetitive options. High speed engines are favored for temporary and emergency power with their lower cost and shorter life; they are not suited for consideration as the new 100 MW power plant. Candidate large medium speed diesel engine includes the following.

- Multiple reciprocating engines (Wärtsilä 50 SG)
- Multiple reciprocating engines (MAN 6 x 18V51/60G)

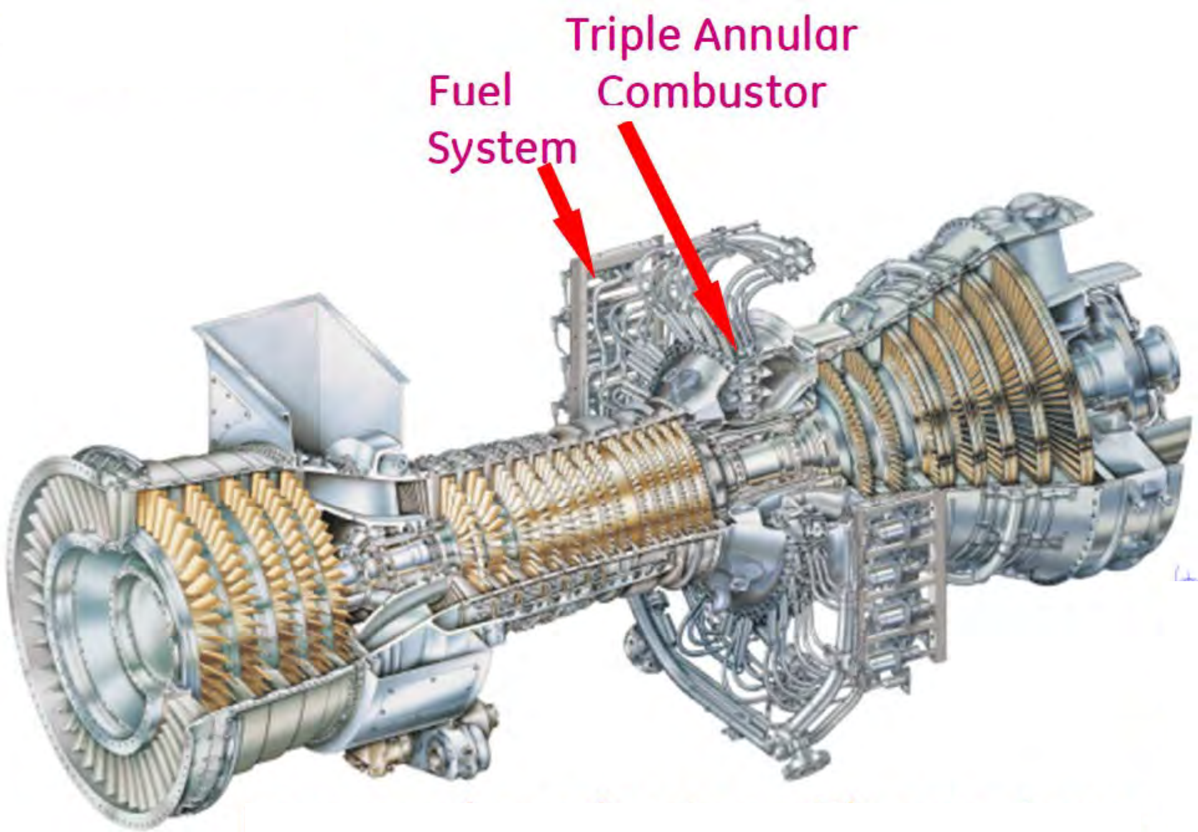
For the purpose of this screening evaluation, the Wärtsilä 50 SG will be utilized as Wärtsilä has experience operating on gas at this size range. The Man 18V51/60 G will be available for shipment only starting in the fall of 2016, and presently have no gas-only operation in this size range.

Thus the following three Power Plant options will be evaluated for the 100 MW generation capacity addition.

4. **Option 1:** (Aero) 2x1 GTCC Plant with the GE LM6000 PF gas turbine generator
5. **Option 2:** (Industrial) 2x1 GTCC Plant with the Siemens SGT 750 gas turbine generator
6. **Option 3:** (Reciprocating) 6x18.5MW Wärtsilä Recip Gas Gen Sets

The following exhibits show the prime movers for each of the three options.

Exhibit 1-15: LM6000PF (circa 42 MW, with15 ppm Dry Combustion System)



Courtesy of GE: [14]

Note: The dry combustion system does not require the addition of water or steam to meet the indicated NOx level of 15 ppmd

Exhibit 1-16: Siemens SGT 750 gas turbine generator (circa 35 MW)

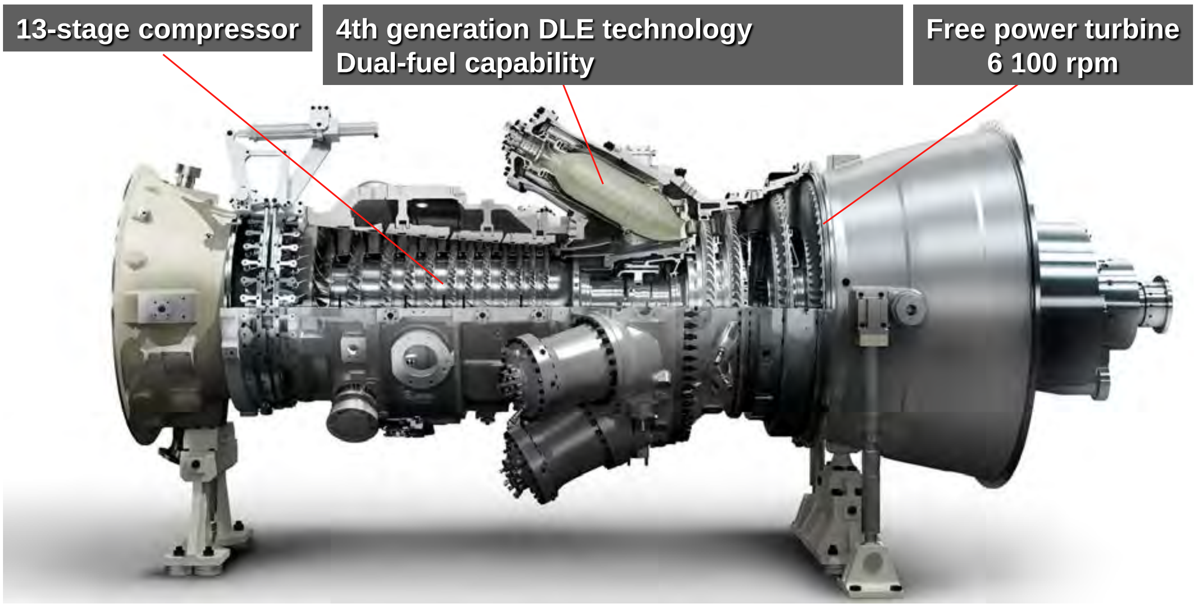


Exhibit 1-17: Wärtsilä 18V50DF (circa 18 MW) Genset

A heat and mass balance for the GE LM6000 PF combined cycle is presented in Exhibit 1-18. A heat and mass balance for the Siemens SGT-750 combined cycle is presented in Exhibit 1-19.

Exhibit 1-18: Heat & Mass Balance for GE LM6000 PF Combined Cycle

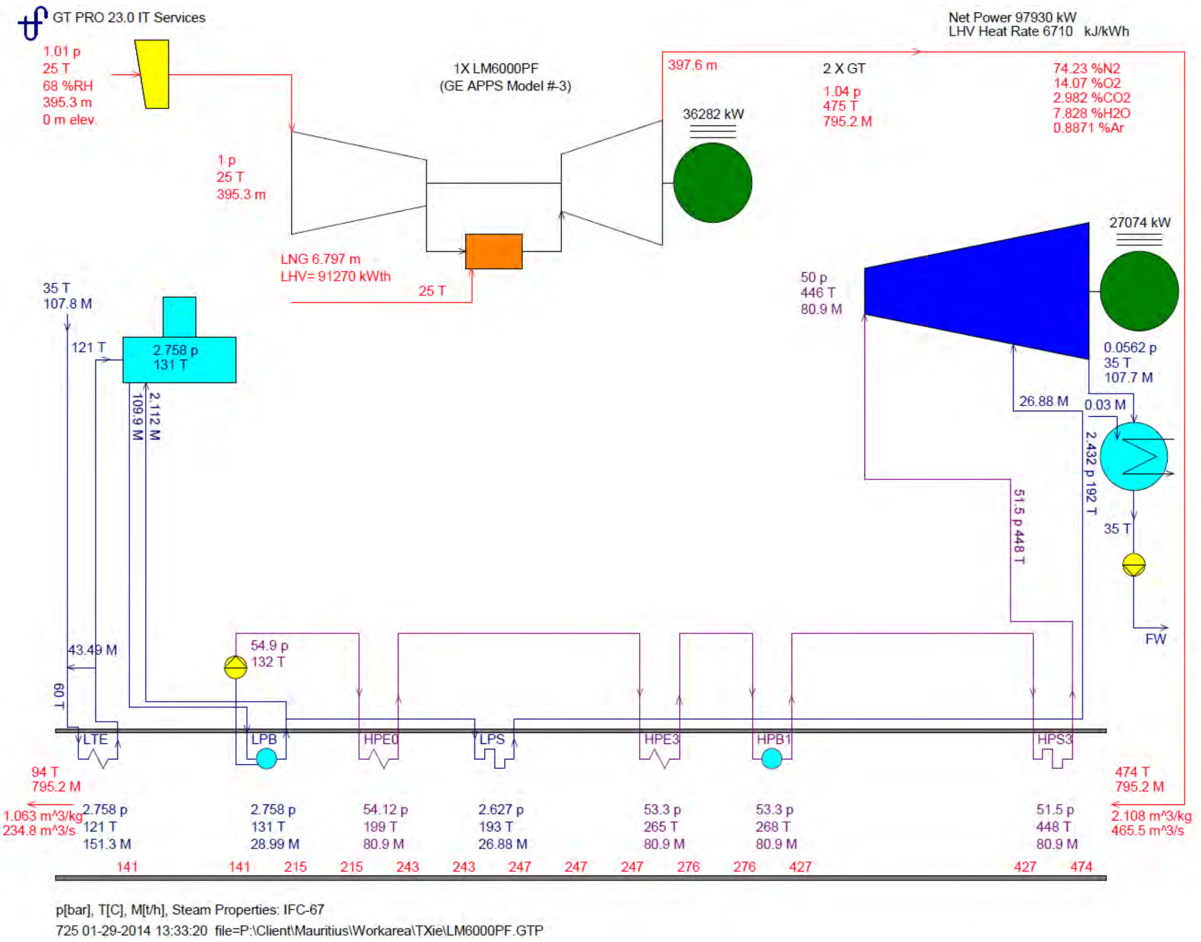
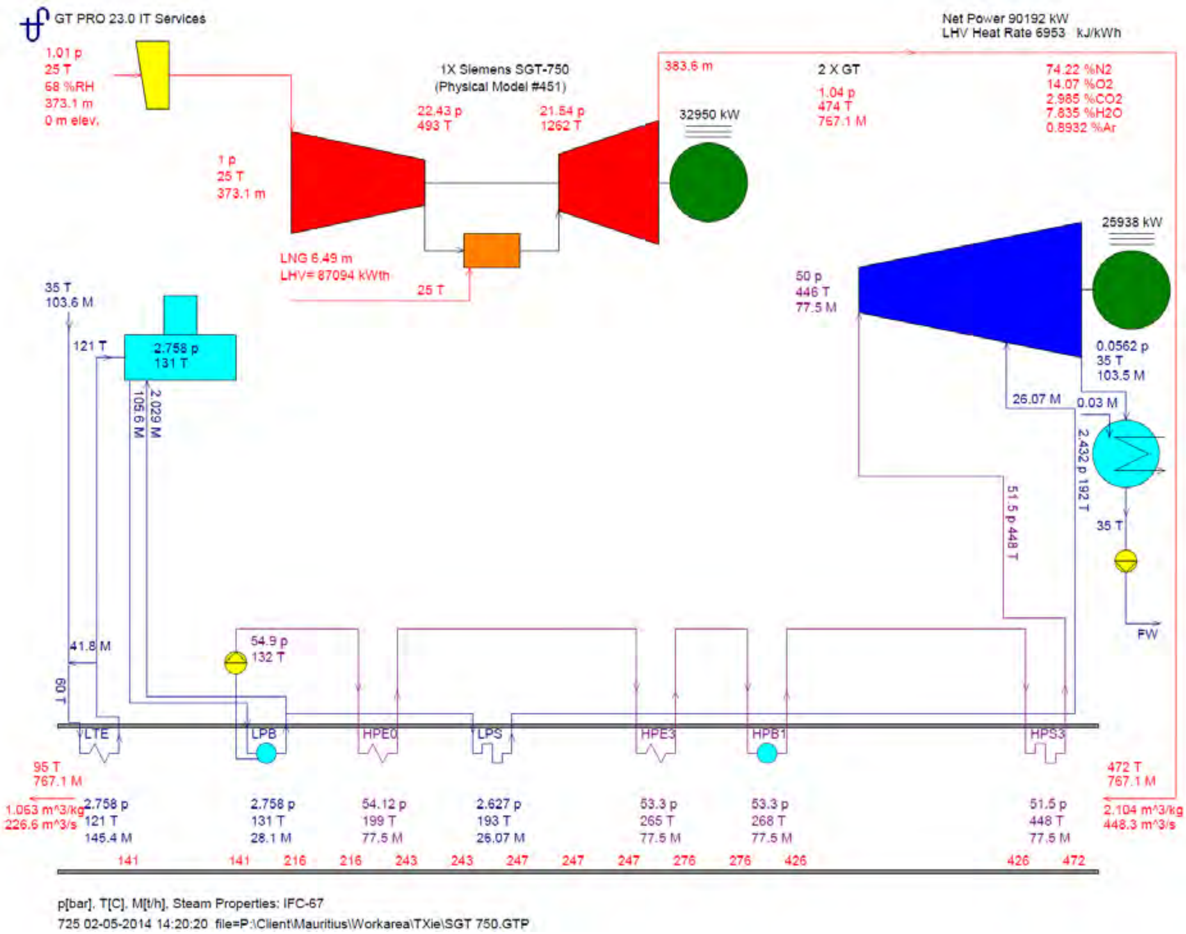


Exhibit 1-19: Heat & Mass Balance for Siemens SGT-750 Combined Cycle



1.3.2 Technical & Cost Assessment

Key gas turbine and gas engine attributes and features for the three candidate 100 MW power plants are presented in Exhibit 1-20, along with the plant performance for the site conditions, and the annual generation and fuel consumption. Salient Features and attributes are presented in Section A of the Exhibit. Plant performance is presented in Section B. Annual electricity generation and utility consumption is presented in Section C.

Exhibit 1-20: 100 MW Generation Capacity – Key Attributes and Performance

BASIS: Ave Annual Ambient of 25.2C / 68% RH, 0 ft Site Elev., 22 C Seawater, Natural Gas, New & Clean — Better / Poorer Attributes

Item	DESCRIPTION	Unit	Option - 1 (Aero) 2x1 CC Plant with GE LM6000 PF GTG	Option - 2 (Industrial) 2 x 1 CC Plant with Siemens SGT 750 GTG	Option - 3 (Recip) 6x18.5 MW Wartsilla Recip Gas Gen Sets	Remarks
A. Gas Turbine / Gas Engine Salient Features & Attributes			2GTGs+2 HRSGs+1 STG in Combined Cycle		6 Recip in Simple Cycle	GTW Handbook / Vendor Data
1	Gas Turbine / Engine Make / Model		GE - LM 6000 PF	Siemens SGT-750	Wartsilla 50 SG	All single fuel (Natural gas only)
2	Gas Turbine Classification		Aeroderivative	Industrial	N.A	
3	Gas Turbine / Gas Engine Output at ISO operation	kW	42,550	34,920	18,320	@Sea Level, 15C, No Cooling
4	Gas Turbine /Gas Engine Heat Rate at ISO,- HHV	kJ/kWh	9,675	10,212	8,539	- Ditto
5	Simple Cycle Efficiency - HHV		37.2%	35.3%	42.2%	
6	Performance Change with Ambinet Temp		Yes	Yes	No (upto about 38C Ambient)	GT output drops and heat rate increases when amb temperature goes up and vice versa
7	Year Introduced - Original Design		2006	2012	2011	
8	Number of Units in Fleet including those on order		>75	2	>90	Fleet basis - based on OEM feedbacks
9	Combustor Type & (NOx)		Dry Low Emissions / 15	Dry Low Emissions / 9	Standard/ 90	NOx in ppmvd @ 15% O2. Gas Engines can be provided with SCR if needed to control NOx
10	Exhaust Configuration		Axial	Side / Top	Side	
11	Generator Cooling		Air Cooled	Air Cooled	Air Cooled	
12	Required Fuel Gas Pressure, barg(2)		47	34	5.3	Minimum at Skid Inlet
13	Is LNG Integration Feasible		Yes	Yes	No	Not considered in the current design due to added complexity. Seawater used for LNG regasification.
14	Inlet Air Cooling		No	No	NA	Could apply to GTs with LNG Integration.
15	Are Building required for GT/Engine?		No - Noise Attenuating Enclosure		Yes	For Noise Control or Maintenance
16	Can the GTs operate in Simple Cycle		Yes w/bypass stack		N.A	Bypass stack assumed for GT's.
17	Start up time to Full Load - Simple Cycle	minutes	10	15	10	
18	Maintenance Penalty for Start/Stops or part load		No	Yes	No	
19	Minimum Turn down Load - Emission Compliance		75%	50%	40%	CC Plant Basis : Option 1 (~37MW), Option 2 (~23MW) and Option 3 (~7.5MW)
20	Ramp Rate	MW/Min	12.5	10	1.6 - 3.2	Per Gt/Engine Basis
21	Expected Availability - average annual values		98.2%	>98.0%	96.0%	Vendor provided Data (simple cycle only)
22	Expected Reliability		99.8%	99.6%	99.0%	- Ditto - , Forced Outage
B. Plant Performance at Reference Site Condition - Gas Fuel (1)						With LNG Integration for GTs
1	Gas Turbine / Gas Engine Output	kW	72,564	65,900	108,606	Total of all units
2	STG Output	kW	27,074	25,938	N.A	
3	Plant Gross Output, kW	kW	99,638	91,838	108,606	
4	Aux Load, kW	kW	1,708	1,649	2,228	
5	Net Power Output, kW	kW	97,930	90,189	106,378	
6	Net Plant Heat Rate - HHV	kJ/kWh	7,441	7,711	8,716	
7	Net Plant Combined Cycle Efficiency - HHV	%	48.4%	46.7%	41.3%	
8	Total Fuel Consumption - HHV	GJ/hr	729	695	927	HHV/LHV ratio = 1.109
9	Demin Water Consumption - Cycle Make Up	M3/hr	1.1	1.0	0.0	Based on 1% Blowdown on CC Plant
C. Annual Electricity Generation and Utility Consumption						
1	Annual Net Electricity Generation	MWH	411,776	379,227	447,298	
2	LNG Consumption - HHV	GJ	3,064,186	2,924,170	3,898,486	
3	Demin Water Consumption	M3	4,533	4,381	0	
4	Annual LNG Requirement (reduced by the availability factor of 96%)	MTPA	0.0571	0.0545	0.0726	Based on LNG Heating Value of 38.76MJ/SM3 HHV & 1 tonne LNG = 1385 Sm3 (MW=17.07)

Notes:
1. All performance are based on Thermoflow software, New & Clean at reference condition as shown.
2. LNG Heating Value : 34.95 MJ/SM^3 (938 Btu/SCF - LHV) & 38.76 MJ/SM^3 (1040 Btu/SCF -HHV). HHV to LHV Ratio = 1.109. SM3 is standard cubic meters at the reference condition of 1 bar and 60°F (15.5°C).

As can be seen in item C4 of the above table, the annual LNG requirement for the three options ranges from 0.054 to 0.073 million tonnes per annum (MTPA) for a 50% capacity factor for the new 100 MW plant.

1.3.3 Screening Analysis

This section presents the following information for the three candidate options:

- LCOE analysis, showing the lowest cost New Plant option for CEB
- The component buildup of the LCOE, showing capital, fuel and fixed and variable O&M costs.
- Sensitivity Plots, showing how the LCOE varies with the following:

- o Capital Cost
- o Fuel Cost
- o Capacity Factor

Exhibit 1-21 continues the option summary for the three candidate options by presenting CAPEX, OPEX, and a levelized cost of Electricity analysis. CAPEX and OPEX are presented in Sections D and E respectively. Economic and operations input used in the economic analysis are presented in Section F, while the Levelized annual cost and levelized cost of electricity (LCOE) are presented in Section G and H respectively. The capital cost in Section D, excludes the cost of bringing the natural gas to the plant boundary[8].

[8] LNG is regassed to NG at the LNG Terminal and transported via sub-sea pipeline to ORF at Les Grandes Salines. From there it is transported by On-shore pipeline to the existing Power Plant. It was discussed at the meetings with CEB that it may be possible to use the existing HFO right of way as an option. Given the pre-feasibility study order of magnitude (+/-50%) cost estimates, the volume of gas required and the relatively short distances from the ORF, the cost for the onshore pipeline is not shown separately, but assumed to be include in the LNG infrastructure CAPEX figures. In further study, this can be broken out in more detail.

Exhibit 1-21: 100 MW Generation Capacity – Cost and Levelized Cost of Electricity

BASIS: Ave Annual Ambient of 25.2C / 68% RH, 0 ft Site Elev., 22 C Seawater, Natural Gas, New & Clean — Better / Poorer Attributes

Item	DESCRIPTION	Unit	Option - 1 (Aero) 2x1 CC Plant with GE LM6000 PF GTG	Option - 2 (Industrial) 2 x 1 CC Plant with Siemens SGT 750 GTG	Option - 3 (Recip) 6x18.5 MW Wartsilla Recip Gas Gen Sets	Remarks
D. CAPEX - Cogen Plant Cost Data x $1000(2)						Power Plant Only
1	Total Plant EPC Costs		$126,783	$123,487	$83,943	Typical for Order of magnitude Estimate
2	Owner's Cost		$12,678	$12,349	$8,394	Based on 5% of Costs
3	**Total Project Cost (TPC)**		$139,462	$135,836	$92,338	
E. Annual O&M Costs - Power Plant Only x $1000						Excluding Fuel & Demin Water
1	Fixed Operating Costs		$1,959	$1,804	$1,596	Adminstration, O&M Personnel
2	Variable Non-Fuel Operating Costs		$1,853	$1,896	$2,684	Maintenance, Chemicals and Consumables
F. Economic and Operations Input Data						
1	Plant Availability			96%		
2	Capacity Factor			50%		Conservatively low CF for baseloaded unit.
3	Annual Operating Hours			8760		
4	Gas Cost,	$/GJ, HHV,		$19.0		Based on $20/MMBtu (HHV)
5	Demin Water Cost	$/M3		$2.8		
6	Discount Rate (%)			8%		
7	Annual Escalation (%)			3%		
8	Plant Book Life, Years			25		
9	Owners Cost			10%		
10	Levelization Factor (Calculated)			1.340		
11	PV Factor (Calculated)			10.675		Based on Uniform series Payment
12	Capital Recovery Factor (Calculated)			0.094		
G. Levelized Annual Operating Costs x$1000(3)			Option - 1: 2x1 CC w/ LM6000 PF	Option - 2: 2x1 CC w/ SGT-750	Option - 3: 6x 50DF Gas Engines	Based on Constant Levelized Dollar
1	Debt Services Costs		$13,065	$12,725	$8,650	Debt services + ROI
2	Fuel Costs		$78,002	$74,438	$99,240	
3	Demin Water Costs		$17	$16	$0	
4	Fixed O&M Costs		$2,624	$2,417	$2,138	
5	Variable Non-fuel O&M Costs		$2,483	$2,540	$3,596	
6	**Total Annual Costs**		**$96,190**	**$92,136**	**$113,624**	
H. Levelized Cost of Electricity (LCOE)		$/MWH				All In US Dollars
1	Debt Services		$31.73	$33.55	$19.34	Debt services
2	Fuel		$189.43	$196.29	$221.87	
3	Demin Water		$0.04	$0.04	$0.00	
4	Fixed O&M		$6.37	$6.37	$4.78	
5	Variable Non-fuel O&M		$6.03	$6.70	$8.04	
6	**Total Levelized Cost of Electricity**		**$233.60**	**$242.96**	**$254.02**	

Notes:
2. LNG Heating Value: 34.95 MJ/SM^3 (938 Btu/SCF - LHV) & 38.76 MJ/SM^3 (1040 Btu/SCF -HHV). HHV to LHV Ratio = 1.109
3. Based on the economic inputs as shown.
4. The yellow highlighted fields are major techno-economic inputs for the determination of the LCOE.

As seen in Item H6, the total LCOE for the three 100 MW power plant options, both gas turbines have a lower LCOE than Option 3, the reciprocating gas engine based option.

The Levelized Cost of Electricity data presented in Exhibit 1-21 is calculated within a project specific evaluation tool which also been utilized to develop LCOE breakdowns and sensitivity analyses that are presented and discussed below.

The overall LCOE as well as the LCOE breakdown is clearly presented in Exhibit 1-22. The LCOE for the gas engine based option (Option 3) is higher than that for the gas turbine combined cycle options (Option 1 & 2). Although the Option 3 debt service and fixed O&M is lower than that of the GTCC options, the fuel cost clearly contributes to a higher LCOE for Option 3.

Exhibit 1-22: 100 MW Generation Capacity – Levelized Cost of Electricity by Option

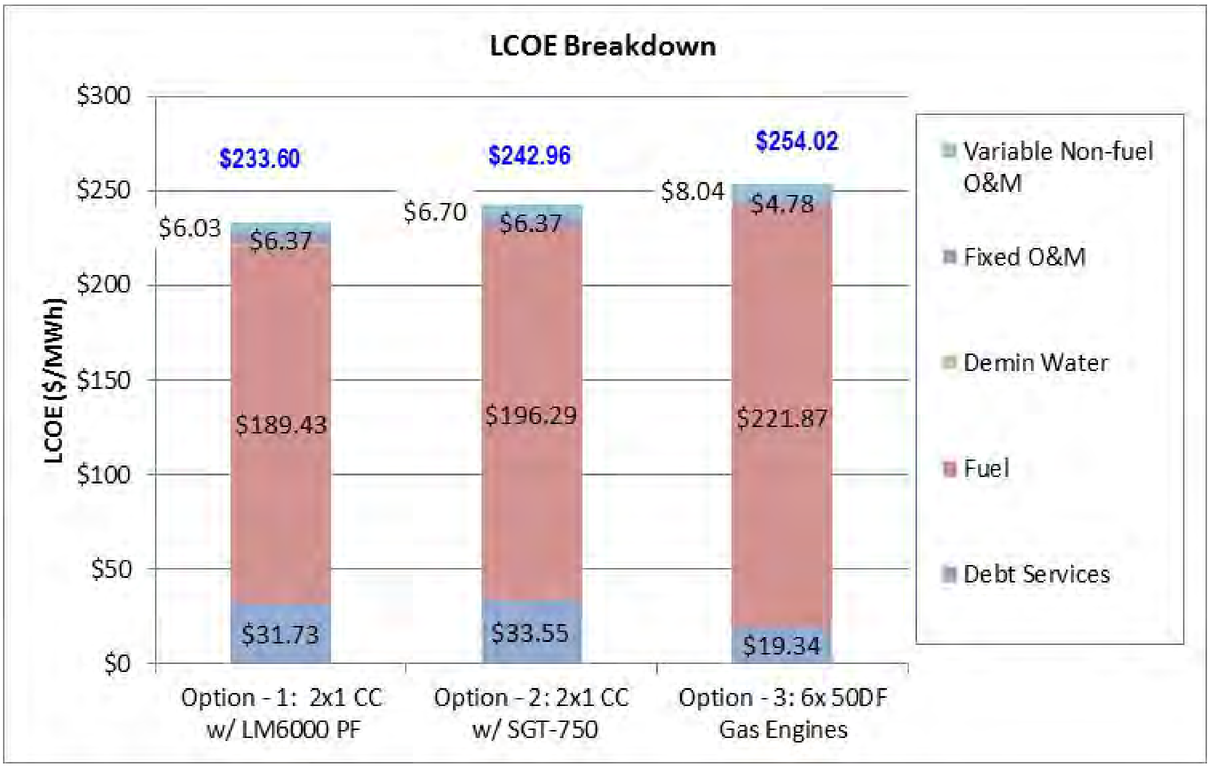


Exhibit 1-23 presents the breakdown of the LCOE for the least cost option (Option 1) in a pie chart with each component of the LCOE expressed in both $/MWh and % of the total cost. For this option, it can be clearly seen that the fuel cost is approximately 81% of the total LCOE cost, followed next by debt service at approximately 14% of the total LCOE.

Exhibit 1-23: 100 MW Generation Capacity – Levelized Cost of Electricity for Least Cost Option

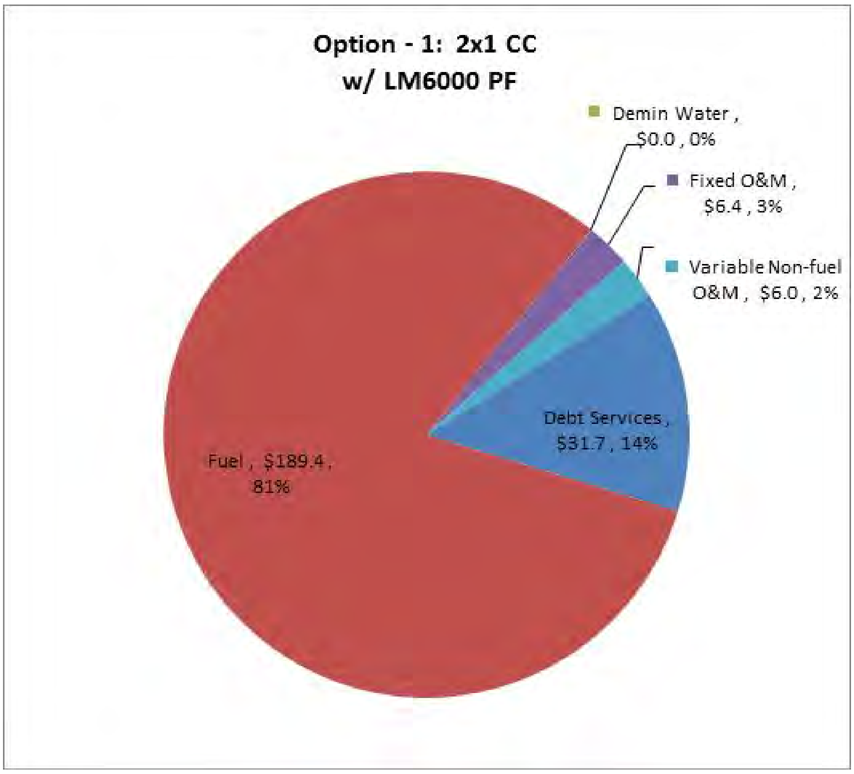


Exhibit 1-24 presents a capital cost LCOE sensitivity plot. On this plot, the Option 1 LCOE of $233.60/MWh is shown as a reference value for comparison with the LCOE of the other options as they are allowed to vary with a capital cost sensitivity factor. This plot illustrates that the least cost option, Option 1, will remain the lowest cost option unless the capital cost of Option 2 could be reduced to below 72% of it estimated value, or unless that of Option 3 could be reduced to below 0% of its estimated value i.e. no capital cost. This plot shows that Option 1 is a relatively robust option with respect to the capital cost variations in light of the predominance of the fuel costs.

Exhibit 1-24: 100 MW Generation Capacity – LCOE and Capital Cost Sensitivity

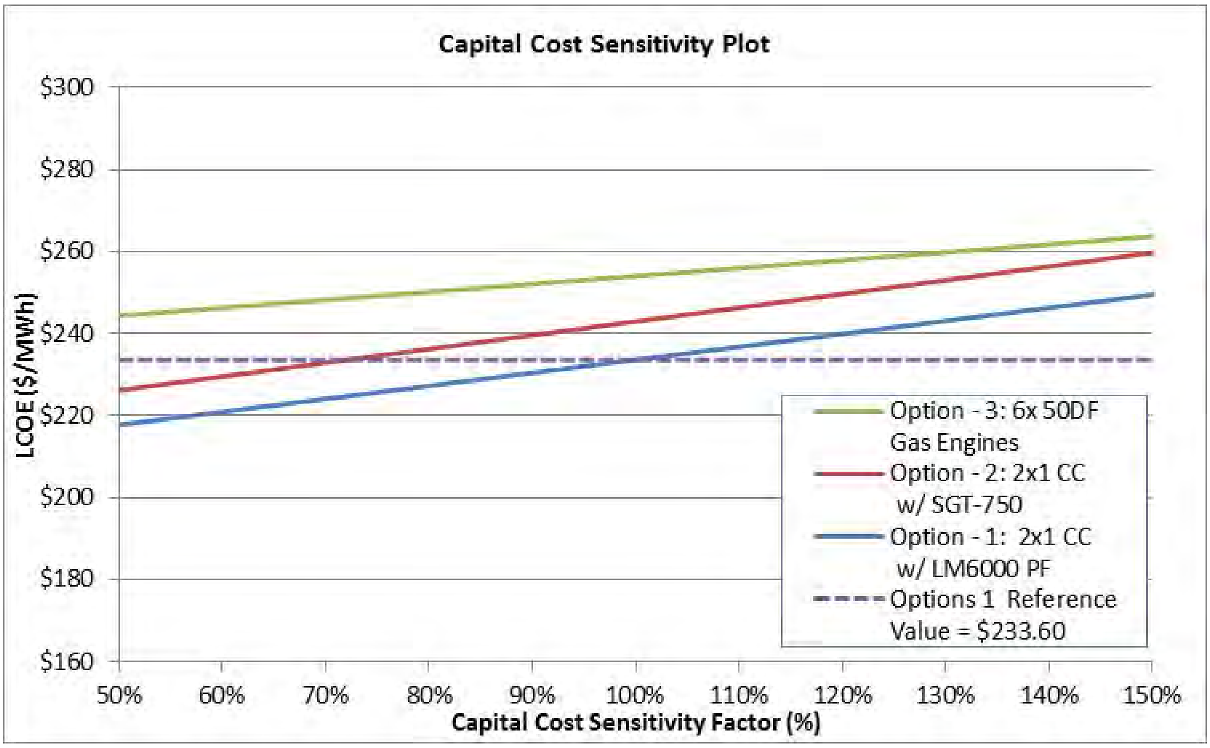


Exhibit 1-25 presents the LCOE sensitivity to fuel cost for the three candidate options. The 100% point is the base fuel cost. This plot illustrates that the Option 1 would remain the least cost option unless the fuel costs would drop to below 37% (circa $7.5/MMBtu) of the expected fuel cost (LNG cost of $20/MMBtu), at which point the lower capital cost of Option 3 would allow it to become the least cost option. Option 2 does not become lower cost than Option 1 regardless of fuel cost sensitivity. As a fuel cost dropping to 37% or lower than its expected value seems unlikely, Option 1 is considered robust compared to Options 2 and 3 from the fuel cost sensitivity perspective.

Exhibit 1-25: 100 MW Generation Capacity – LCOE and Fuel Cost Sensitivity

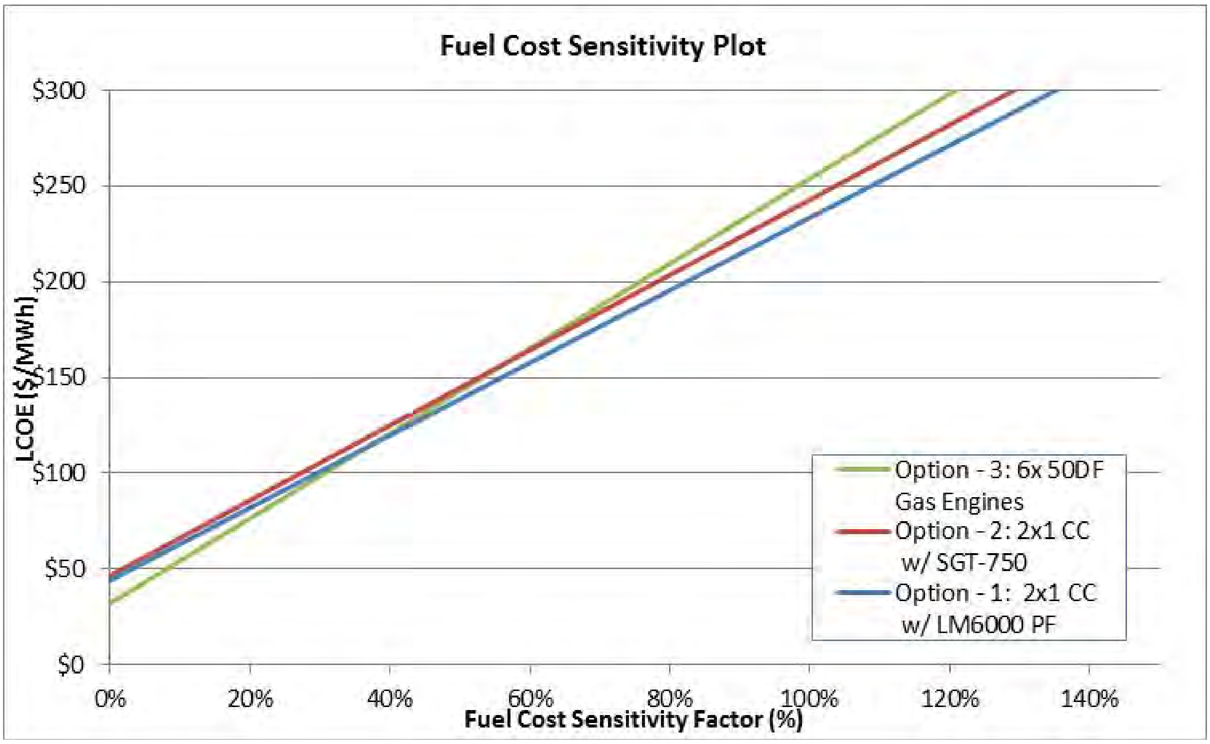
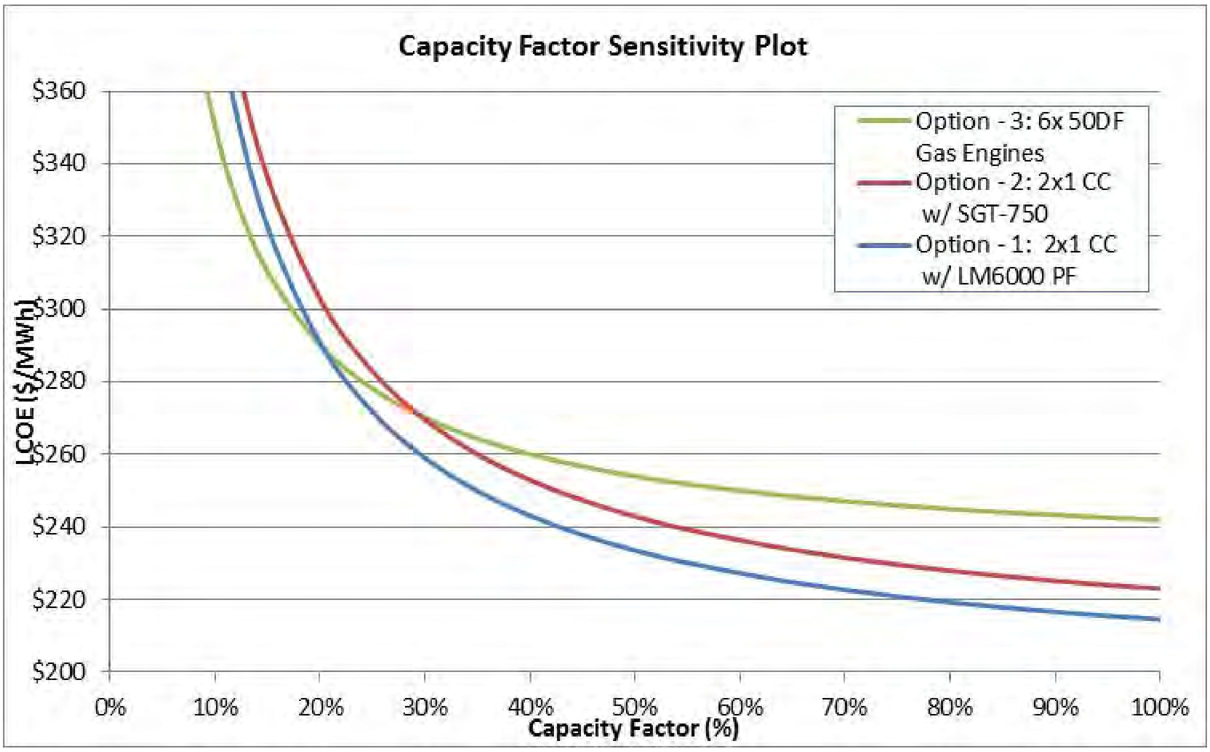


Exhibit 1-26 presents the LCOE sensitivity to the plant capacity factor. The base capacity factor assumption used in the LCOE analysis is 50%. At this capacity factor and above, the gas turbine options have the lowest LCOE. In fact, the annual capacity factor of the new plant would have to drop to approximately 20% before the diesel option becomes equivalent or better than Option 1 on the LCOE basis. Thus Option 1 is favored for all capacity factors of 20% and above. Since the new power plant would be anticipated to be a baseloaded unit, Option 1 appears favoured.

Exhibit 1-26: 100 MW Generation Capacity – LCOE and Capital Factor Sensitivity



1.3.4 Construction Schedule

An indicative project duration for a single phase 2x1 GTCC installation as described above is expected to be circa 25 to 27 months after notice to proceed (NTP).

This duration is based on an expected delivery schedule of major equipment FOB Port of Export based on current 2x2x1 market conditions for the 100 MW class plant as follows (with lead times in brackets).

- Combustion turbine generator (13-15 months[9])
- HRSG (9-10 months)
- Steam turbine generator (16-18 months)

The STG has the longest lead time. Delivery of all other major equipment in the power plant is expected to be in the 12 - 18 months after receipt of order (ARO) and is not expected to be in the critical path.

The time between commissioning the plant after delivery of the 30 MW class STG is typically about 6 months. Allowing for 2 months delivery, and 1 month for various performance and reliability testing,

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[9] The cited lead times exclude delivery duration.

no productivity issues for Mauritius yields a total of about 25-27 months after NTP. This does not include the Pre-NTP processes such as permitting, financing and others.

An indicative project duration for the medium speed diesel power plant is expected to be about 19 to 23 months. This is based on an expected lead time of approximately 8-9 months for the first reciprocating engine ARO. The last engine for the six unit installation would be expected approximately 12 months ARO. Allowing for 1 month delivery and 6-10 months for construction and commissioning yields a total of about 19-23 months after NTP. This does not include the Pre-NTP processes such as permitting, financing and others.

In summary the project construction schedule for the candidate options are presented in Exhibit 1-27. The schedules cover EPC notice to proceed to commercial operation.

Exhibit 1-27: Power Plant Project Duration

Option No.	Option Description	Project Duration
1	2x1 GTCC Plant - GE LM6000 PF CTG (Aero)	Circa 25-27 months
2	2x1 GTCC Plant - Siemens SGT 750 CTG (Industrial)	Circa 25-27 months
3	6x18.5 MW Wärtsilä Gas Gen Sets (Reciprocating)	Circa 19-23 months

1.3.5 Addition Information for the LM6000 based Power Plant

The scheduled maintenance actions, intervals and duration for the favoured option, the LM6000 option, are presented in Exhibit 1-28.

Exhibit 1-28: LM6000 Typical Scheduled Maintenance Actions, Intervals and Duration

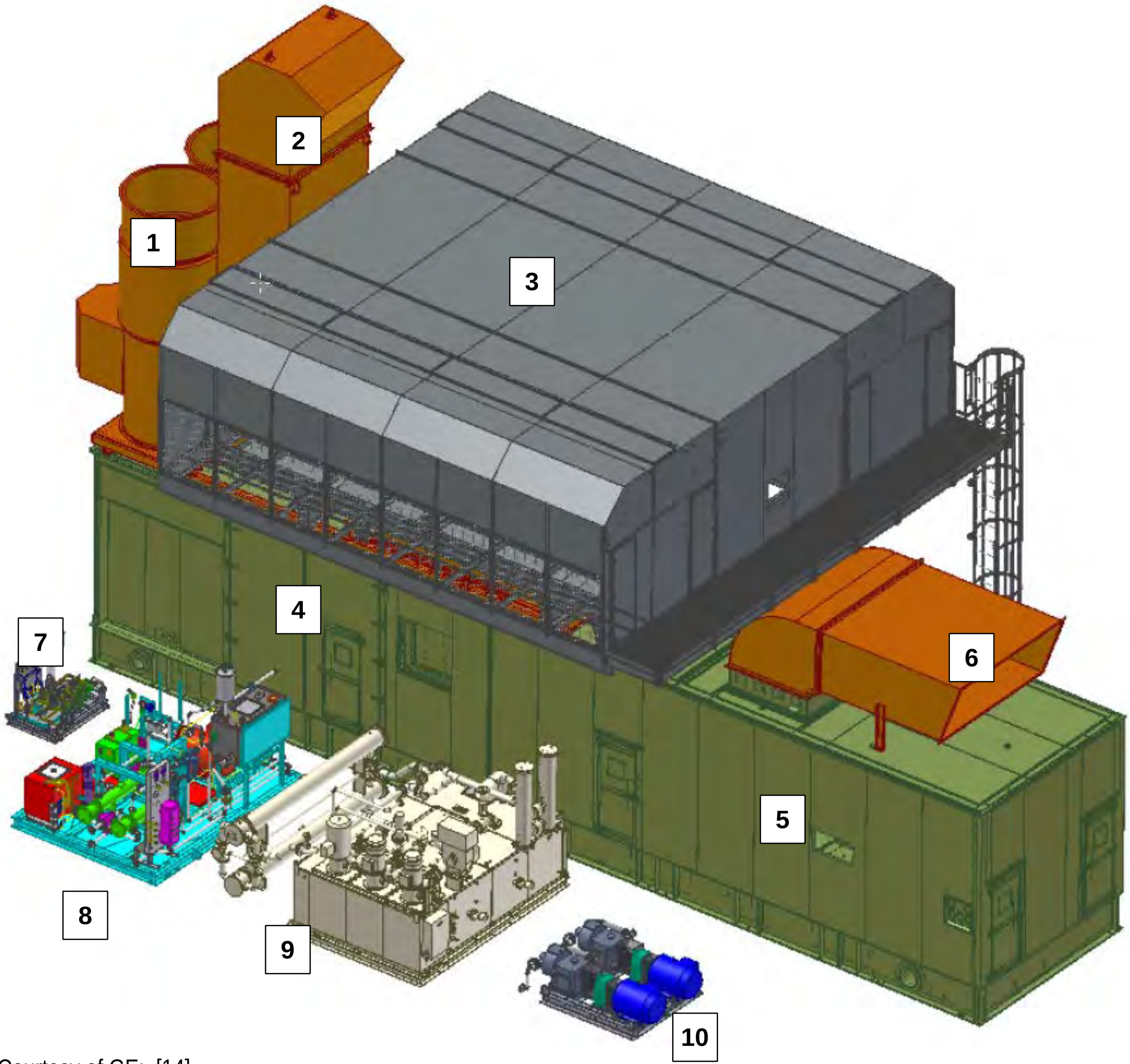
Interval	Scheduled Maintenance Action	Outage Duration
4,000 hours (every 4K h)	Borescope Inspection (includes cool-down time)	12 hours
25,000 hours	Hot Section Interval* 1) On-Site Hot Section Replacement (Combustor, HPT, IPT)	4 days [(a)]
50,000 hours	Depot Maintenance [(b)] 1) Major Hot Section Overhaul (Combustor, HPT, IPT) 2) Inspect Booster, Intercooler, Scroll Frames, HPC, Aft Shaft & Bearings[(c)] 3) Power Turbine Overhaul	4 days [(a)]
75,000 hours	Hot Section Interval [(b)] 1) On-Site Hot Section Replacement (Combustor, HPT, IPT)	4 days [(a)]
100,000 hours	Depot Maintenance [(b)] 1) Major Hot Section Overhaul (Combustor, HPT, IPT) 2) Inspect Intercooler, Scroll Frames, HPC, Aft Shaft & Bearings [(c)] 3) Power Turbine Overhaul 4) Booster & Shaft Inspection/Maintenance	4 days [(a)]

Notes:
- (a) Rotable module installed during maintenance period.
- (b) Lease/spare “supercore” and Power Turbine modules are installed during maintenance period. For depot maintenance, outage duration is 60 days if no spare/lease module(s) are used.
- (c) Roller and ball bearings are replaced at 50,000 hours; hydrodynamic bearings are inspected.

Reference [13]

A typical LM6000 gas turbine generator and package arrangement is shown in Exhibit 1-29.

Exhibit 1-29: Typical LM6000 and package arrangement



Courtesy of GE: [14]

Legend: 1. Variable Bypass Valve (VBV) Ducting, 2. Turbine Enclosure Exhaust Duct, 3. Air Inlet Filter, 4. Turbine Enclosure, 5. Generator Enclosure, 6. Generator Ventilation Exhaust Duct, 7. Fuel Gas Skid, 8. Auxiliary System Skid, 9. Lube and Control Oil Skid, 10, Sprint Pump Skid.

Fitting within a Network with Renewable Power

One of the challenges of renewable power utilization is the unpredictable non-dispatchable nature of the solar and wind based renewable power. As such, renewable power needs to be firmed up by the system spinning reserve and peaking units that can ramp up and down appropriately.

Aero-derivative engines, such as the LM6000, have numerous features that aid in this application when operated in simple cycle mode, and to a lesser degree when in combined cycle mode including:

- Ability to start and stop daily without affecting the GT maintenance schedule.
- Cold Start to full load within 10 minutes (simple cycle)
- GT ramp rate of 12.5MW/min per LM6000 (simple cycle)
- In the combined cycle, the plant can ramp up or down at a rate of about 27 MW/min

The LM6000 based combined cycle can be utilized in a network with solar or wind renewable power as part of an overall resource plan. In the CEB network, the Nicolay peakers, the diesel engines, and the LM6000 combined cycle can all contribute in responding to a generation demand profile resulting partly from renewable power generation variations. Increasing levels of renewable power will require continued evaluation of the system's ability to handle the potentially increasing mismatch between demand and generation[10].

1.3.6 Discussion and Recommendations

Based upon the above results, Option 1, the 2x1 GTCC based on the LM6000 PF, is recommended for consideration for the capacity addition at Les Grandes Salines. This recommendation is based on the option having the lowest LCOE of the three candidate options, as well as showing a significant level of robustness, evidenced by stamina under varying sensitivities including capital cost, fuel cost and capacity factor sensitivities.

1.4 Power LNG Supply Requirement

This section provides information on the LNG supply requirement for both the new and existing plant where conversion is possible. Where conversion is not possible in the existing units, additional information is presented assuming that supplemental new units are added to maximize the LNG utilization.

Exhibit 1-30 presents the LNG consumption of the three (3) 100MW Power Plant options for capacity factors 0 to 100% based on full load efficiency. Since a major focus of this study is the evaluation of the feasibility of LNG utilization, this graph is useful in understanding the quantity of LNG required for different utilization scenarios of the new 100 MW Power Plant. The LNG consumption of Option 1 assuming 100% capacity factor would be 0.119 MTPA.

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[10] The LM 6000 CTG has an inertia "H" constant of 1.2kW-sec/kVA and moment of inertia of 970kg-m^2. Evaluating the effect of this inertial addition on the Mauritius electrical system, which may include the future addition of renewable resources, and its ability to dampen frequency variations following the loss of load/generation requires additional analysis in a future phase of the project.

Exhibit 1-30: 100 MW Generation Capacity – LNG Consumption as Function of Capacity Factor

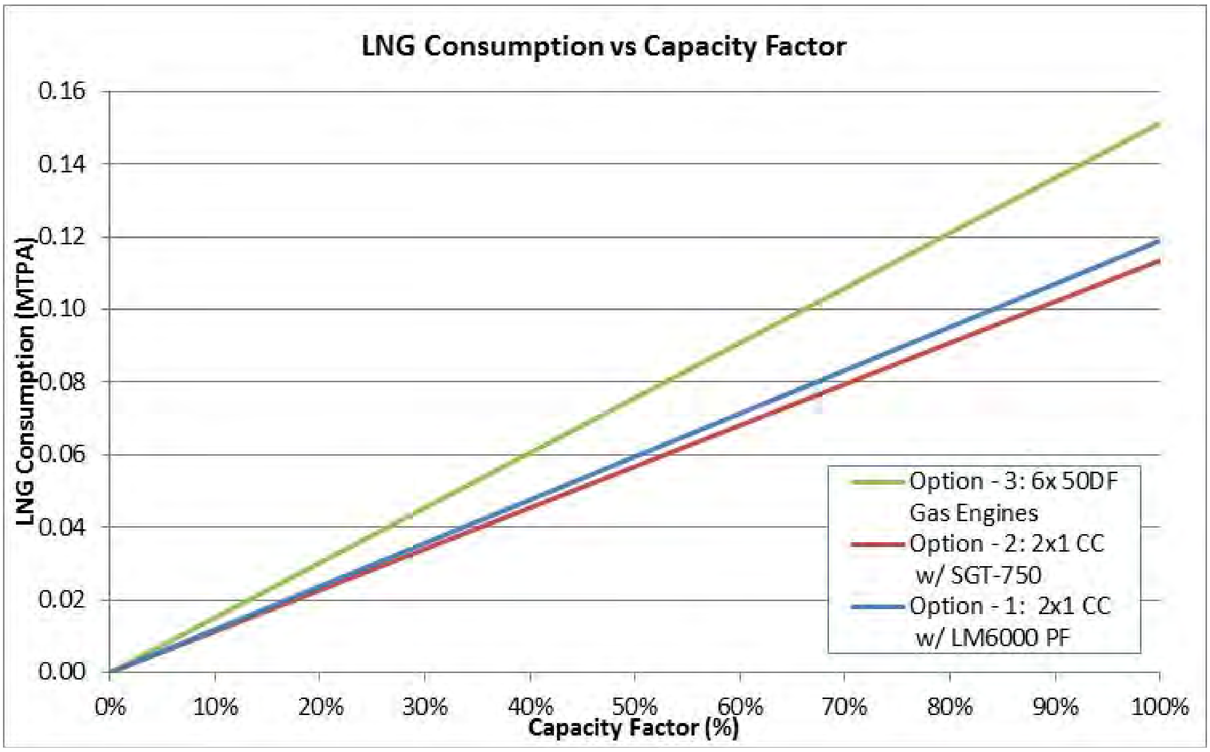


Exhibit 1-31 presents the potential LNG consumption of the CEB power plants in three (3) Categories:

- The new nominal 100 MW plant at Les Grandes Salines,
- The existing CEB units that can be converted to LNG consumption as discussed above, and
- New CEB units that are assumed to replace the CEB units that can not be converted to LNG firing.

The capacity factors used in Exhibit 1-31 for the existing plants are those as anticipated by the CEB for 2013 to 2022. The capacity factor for the new 100 MW plant at the Les Grandes Saline site has been assumed to be 50%. As a baseloaded plant, it could be notably higher. For reference, the Ft George Power Plant is a baseloaded plant and has an annual capacity factor of 55%, while the IPPs are baseloaded and operate above 80% [3, p55]. It is noted that the St Louis units G1-G5 are planned to be retired, and replaced with 4 x 15 MW units in 2016. These new St Louis units are reflected in Exhibit 1-31. The total LNG consumption from the CEB plants based on this total conversion/replacement and operation is approximately 0.267 MTPA.

Exhibit 1-31 also has a column that indicates whether the LNG consumption by a candidate plant is considered to be in the "Base" LNG conversion case or whether it is in an "Aggressive" LNG conversion case made possible through the replacement of units that are not convertible. WorleyParsons is not recommending the replacement of the non-convertible units through the addition of supplemental new units, but are presenting this information to aid in the quantifying what the maximum potential LNG consumption could be from the CEB thermal power plants. Rows at the bottom of the table present the LNG consumption for the Base conversion and High conversion case. The Nicolay units are not included in the Base or Aggressive LNG consumption case because of the reasons discussed in Section 1.2.5.

Exhibit 1-31: Estimated LNG Consumption from CEB Power Plants

Item	Plant / Gas User	Plant Capacity (kW)	Plant Heat Rate, HHV (kJ/kWh)	Annual Capacity Factor (%)	Elec. Gen. (GWH)	LNG Consumption (MTPA)	Base or Aggressive LNG Case	Notes
1.0	**New Plant - Les Grandes Saline**	97,930	7,441	50%	**429**	**0.059**	Base	
2.0	**Existing Plants -Convertible to LNG**							
2.1	Ft George		-	55%	-	0.000	N.A.	No Conversion
2.2	Ft Vicotoria (6x15,200 kW)	91,200	8,850	35%	280	0.046	Base	G1-G6 W16V50DF
2.3	St Louis (3x13,800 kW)	41,400	8,850	30%	109	0.018	Base	G7-G9 W16V50DF
2.4	Nicolay G1	21,525	12,838	3%	6	0.001	N.R.	G1 - GE Frame 5
	Nicolay G2	21,525	12,667	3%	6	0.001	N.R.	G2 - GE Frame 5
	Nicolay G3	32,800	11,339	3%	9	0.002	N.R.	G3 - GE Frame 6B
	Subtotal: Existing Plants -Converted	**208,450**			**408**	**0.069**		
3.0	**Existing Plants -If Replaced with New Units to burn LNG (Assume heat rate of W16V50SG - Gas only)**							
3.1	Ft George (2x24, 3x30 MW)	134,000	8,715	55%	646	0.105	Aggressive	Replace G1-G5
3.2	Ft Vicotoria (2x8.5 MW)	17,000	8,715	35%	52	0.008	Aggressive	Replace G11 & G12
3.3	St Louis (4x15 MW)	60,000	8,715	30%	158	0.026	Base	G1-G5 Retired. Replaced w/ 4x15 MW
3.4	Nicolay			3%	-	0.000	NA	
	Subtotal: Existing Plants -Replaced	**211,000**			**855**	**0.139**		
	Total of All Units	**517,380**			**1,693**	**0.267**		New, converted, replaced.
	Total LNG Consumption - Base	**290,530**			**975**	**0.149**	**Base**	
	Incremental LNG Cons. - Aggressive	**151,000**			**698**	**0.113**	**Aggressive**	Incremental (Agges-Base)
	Total LNG Consumption - Aggressive	**441,530**			**1,673**	**0.262**	**Aggressive**	

Notes:

1 Capacity factors for the existing plants are the anticipated annual load factors indicated by CEB in the IEP for 2013 to 2022.
2 Capacity factor for the New Les Grandes Saline is assumed to be 50%.
3 For the recip engines, the plant heat rate is the gas only heat rate, used to determine the LNG consumption rate.
4 The converted recip engine heat rate is based on the Wartsila W16V50DF performance.
5 N.R. - Not Recommended for conversion to LNG.
6 Conversion to LNG at Nicolay reflects 2.5% increase on capacity and 1.4% reduction (improvement) on heat rate compared to oil firing.
7 The Base conversion case represents 57.6% of the GWH for all CEB thermal units, based on above capacities and capacity factors.
8 The Aggressive conversion case represents 98.8% of the GWH for all CEB thermal units, based on above capacities and capacity factors.

The information above is based on the capacity factors presented in the Integrated Electric Plan [3] for the years 2013 to 2022. The anticipated electric growth cited in the Integrated Electric Plan indicates that the electric generation will grow over time. A table of the annual electric generation by year for three electric demand growth scenarios (Base, High, and Low) is presented in Exhibit 1-32. The values in this table are based on the notes listed in the exhibit.

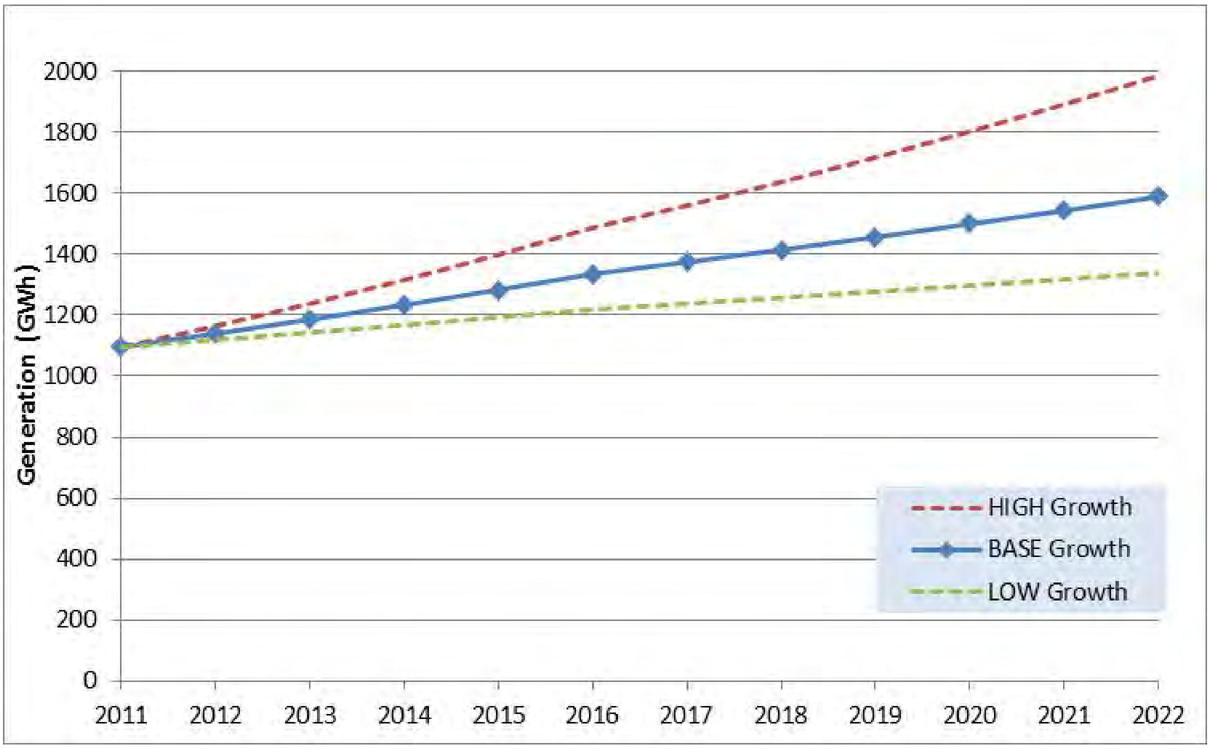
Exhibit 1-32: Anticipated CEB Annual Electric Generation per IEP Growth Projections

			1	2	3	4	5	6	7	8	9	10	11
BASE Growth		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Growth	%	BASE	4.03%	4.03%	4.03%	4.03%	4.03%	2.94%	2.94%	2.94%	2.94%	2.94%	2.94%
Generation	GWH	1096	1140	1186	1234	1284	1335	1375	1415	1457	1499	1544	1589
HIGH Growth		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Growth	%	BASE	6.29%	6.29%	6.29%	6.29%	6.29%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%
Generation	GWH	1096	1165	1238	1316	1399	1487	1560	1637	1718	1803	1892	1986
LOW Growth		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Growth	%	BASE	2.15%	2.15%	2.15%	2.15%	2.15%	1.58%	1.58%	1.58%	1.58%	1.58%	1.58%
Generation	GWH	1096	1120	1144	1168	1193	1219	1238	1258	1278	1298	1318	1339

Notes: 1. CEB Generation in 2011, 1096 GWH, per IEP report, p 49.
2. Base, High and Low Projected Annual Growth Rates per IEP report, p 39.
3. Assumes split between total generation and CEB remains the same over time.

The anticipated annual generation for the CEB units documented above is also presented graphically in Exhibit 1-33.

Exhibit 1-33: Anticipated CEB Annual Electric Generation per IEP Growth Projections



Since there is not a lot of detail in the IEP on capacity factors or generation by unit, the split between the CEB units and the other units (IPP's, new CT Power coal unit, hydro, etc.), the anticipated CEB annual generation values and plots presented in Exhibit 1-32 and Exhibit 1-33 are not necessarily exact, but are provided as indicative values. These values are based on the split between the CEB thermal units and the total generation staying the same as documented in 2011. These indicative generation values are useful in estimating preliminary LNG consumption values in this pre-feasibility stage. Additional analysis could be developed at subsequent stages of the project. Exhibit 1-34 illustrates the combinations of the three anticipated CEB annual generation growth (Base, High and Low) scenarios and the two LNG conversion scenarios (Base and Aggressive) that together form the various LNG demand scenarios. The Base Electric Growth scenario and the Base LNG Conversion scenario (new 100 MW GTCC, conversion of 6 Ft Victoria units G1-6, conversion of 3 St Louis units G7-9 and the replacement of St Louis G1-5 with 4x15 MW units) together form the "Base" LNG demand basis from the power sector..

Exhibit 1-34: LNG Consumption Scenarios

	LNG Conversion Scenario	
Electric Growth Scenario	**Base LNG Conversion**	**Aggressive LNG Conversion**
High Electric Growth	✓	✓
Base Electric Growth	✓ (Base)	✓
Low Electric Growth	✓	✓

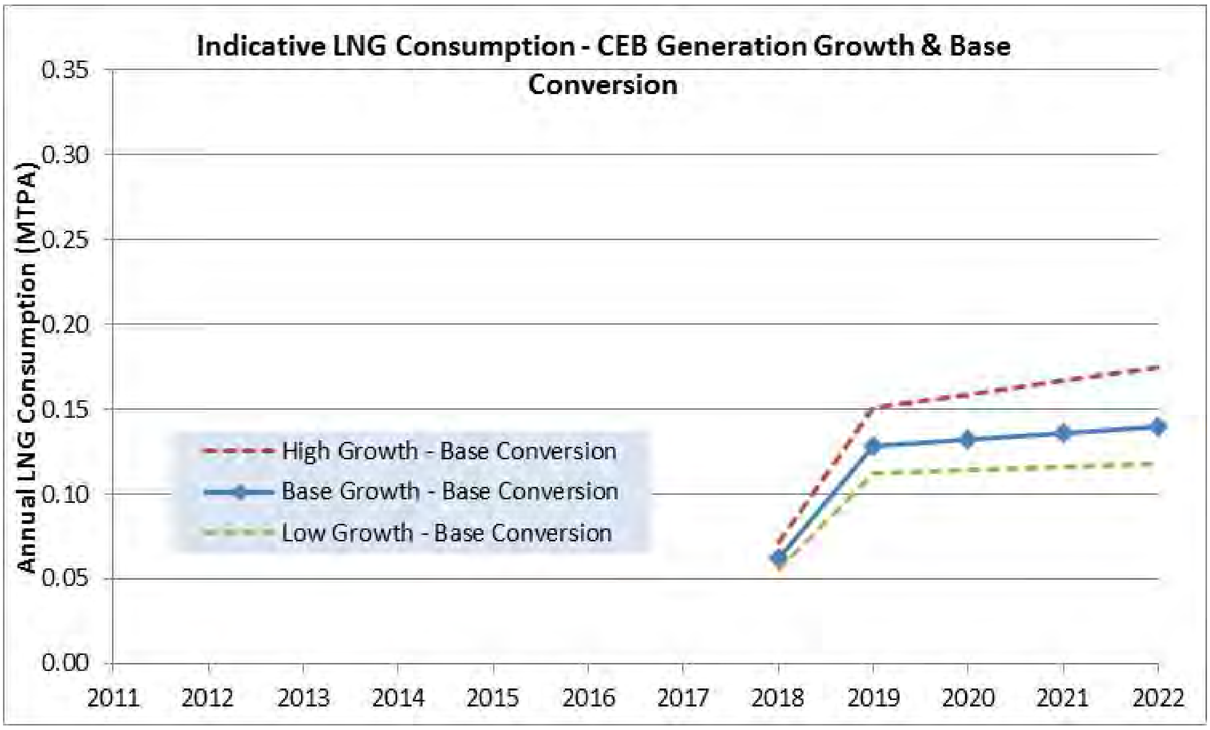
Based on LNG being available about mid-year 2018, indicative LNG consumptions are indicated over time for the three growth scenarios for the Base Case LNG Conversion Scenario in Exhibit 1-35 and Exhibit 1-36.

Exhibit 1-35: Indicative LNG Consumption - Projected CEB Generation Growth & Base LNG Conversion

LNG Consumption	Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Base Growth - All CEB	GWh	1096	1140	1186	1234	1284	1335	1375	1415	1457	1499	1544	1589
High Growth - All CEB	GWh	1096	1165	1238	1316	1399	1487	1560	1637	1718	1803	1892	1986
Low Growth - All CEB	GWh	1096	1120	1144	1168	1193	1219	1238	1258	1278	1298	1318	1339
Base Growth - Base Conversion	GWh								408	839	864	889	915
High Growth - Base Conversion	GWh								472	990	1039	1090	1144
Low Growth - Base Conversion	GWh								362	736	748	759	771
Base Growth - Base Conversion	MTPA								0.062	0.128	0.132	0.136	0.140
High Growth - Base Conversion	MTPA								0.072	0.151	0.159	0.167	0.175
Low Growth - Base Conversion	MTPA								0.055	0.113	0.114	0.116	0.118

Note: 1. The GWh for the LNG converted units in 2019 on, are based on the 57.6% fraction of All CEB units as shown above.
2. LNG assumed available in early 3Q2018. The 2018 GWh production & MTPA consumption is approximated as half of the full year value.
3. The annual GWh growth rate of that generated by LNG Converted units is assumed to be that of the rest of the total demand.
4. LNG Consumption used at average rate of 0.153 MTPA/MWH
5. LNG Consumption based on the Base Case LNG Conversion scenario.

Exhibit 1-36: Indicative LNG Consumption - Projected CEB Generation Growth & Base LNG Conversion Plot



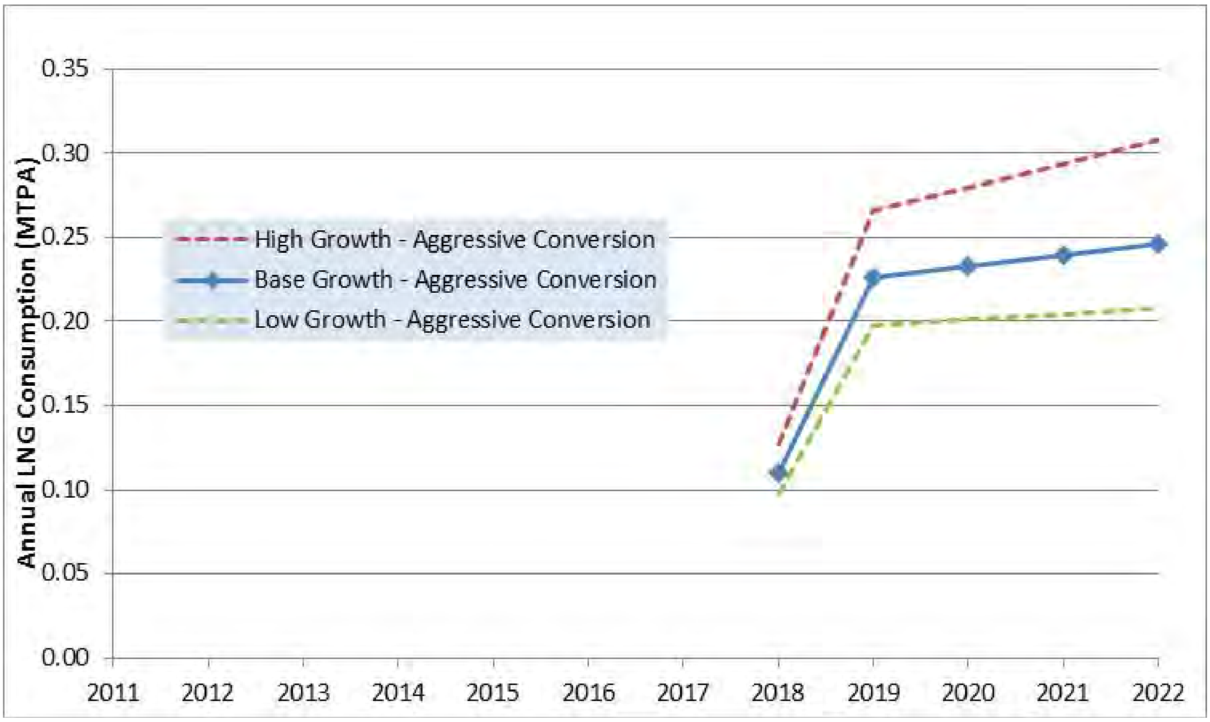
Based on LNG being available about mid-year 2018, indicative LNG consumptions are indicated over time for the three growth scenarios for the Aggressive LNG Conversion Scenario in Exhibit 1-37 and Exhibit 1-38.

Exhibit 1-37: Indicative LNG Consumption - Projected CEB Electric Generation & Aggressive LNG Conversion

LNG Consumption	Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Base Growth - All CEB	GWh	1096	1140	1186	1234	1284	1335	1375	1415	1457	1499	1544	1589
High Growth - All CEB	GWh	1096	1165	1238	1316	1399	1487	1560	1637	1718	1803	1892	1986
Low Growth - All CEB	GWh	1096	1120	1144	1168	1193	1219	1238	1258	1278	1298	1318	1339
Base Growth - Aggressive Conversion	GWh								699	1439	1482	1525	1570
High Growth - Aggressive Conversion	GWh								809	1698	1782	1870	1962
Low Growth - Aggressive Conversion	GWh								622	1263	1283	1303	1323
Base Growth - Aggressive Conversion	MTPA								0.110	0.226	0.232	0.239	0.246
High Growth - Aggressive Conversion	MTPA								0.127	0.266	0.279	0.293	0.308
Low Growth - Aggressive Conversion	MTPA								0.097	0.198	0.201	0.204	0.208

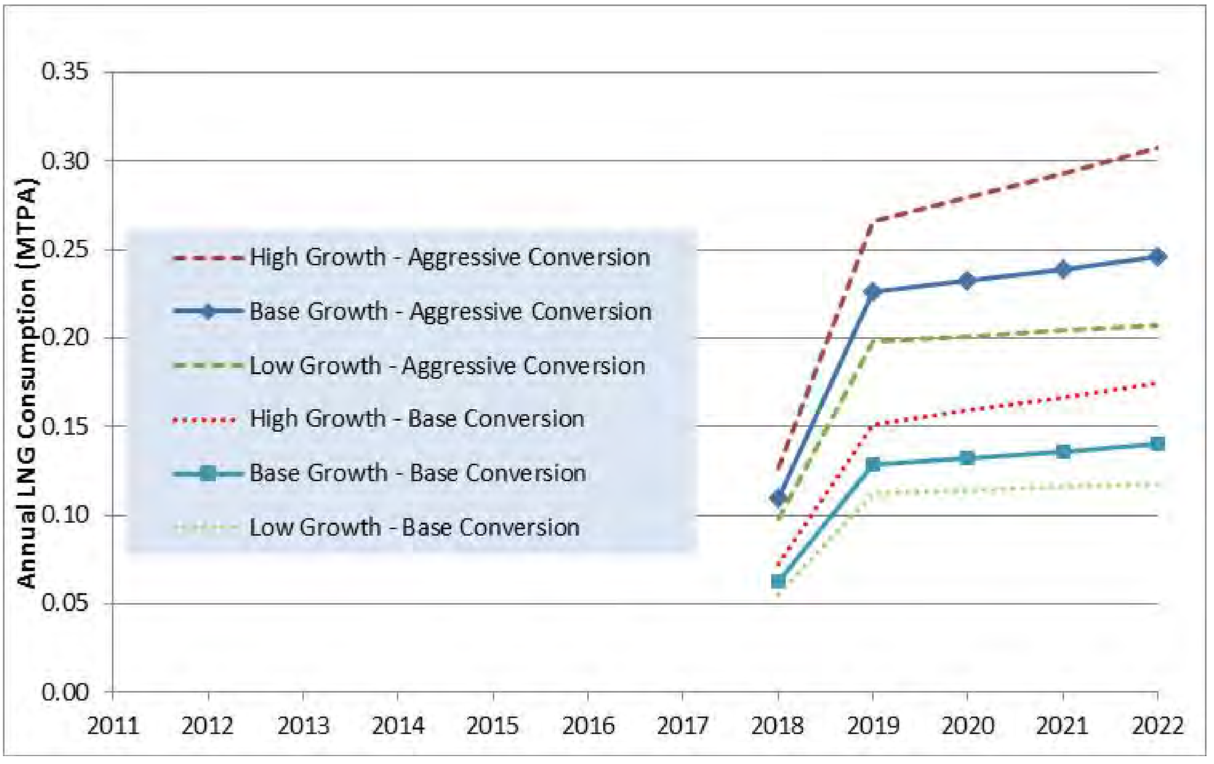
Note:
1. The GWh for the LNG converted units in 2019 on are based on the 98.8% fraction of All CEB units as shown above.
2. LNG assumed available in early 3Q2018. The 2018 GWh production & MTPA consumption is approximated as half of the full year value.
3. The annual GWh growth rate of that generated by LNG Converted units is assumed to be that of the rest of the total demand.
4. LNG Consumption used at average rate of 0.157 MTPA/MWH
5. LNG Consumption based on the Aggressive Case LNG Conversion scenario.

Exhibit 1-38: Indicative LNG Consumption - Projected CEB Generation Growth & Aggressive LNG Conversion Plot



The indicative LNG consumption for both the Base Case and Aggressive Case LNG conversion, and for each of the three growth scenarios are presented in Exhibit 1-39.

Exhibit 1-39: Indicative LNG Consumption - Projected CEB Generation Growth and Base and Aggressive LNG Conversion Plot



2. LNG POTENTIAL FOR TRANSPORT SECTOR

2.1 Introduction

To help launch a sustainable natural gas industry in Mauritius it is important to consider all possible client demands which could be practically satisfied. In this regard it is considered possible that some clients within the following sectors could be attracted to using gas; the table below presents the ktoe energy usage of various sectors for 2012 and their percentage contribution to the total.

Exhibit 2-1: Indication of sector contribution to LNG / NG use [42]

Sector	Total ktoe 2012	Approx. MTPA LNG equivalent	%
Power (all incl. CEB and IPP)	591.6	0.48	50
Road transport	292.3	0.24	25
Manufacturing	215.0	0.17	18
Commercial	84.0	0.07	7
Sub total	**1182.9**	**0.96**	**100**

The following sectors have been excluded from the pre-feasibility study:

Exhibit 2-2: Sectors that have been excluded from the pre-feasibility study

Sector	Total ktoe 2012	Reason
Air and Sea Transport	148.4	No current commercially viable aeronautical gas solution, minimal sea transport
Households	120.0	Too costly to supply and low demand
Agriculture & Other	7.5	Small scale rural demand – uneconomic to supply

For this study, CEB specifically sought some guidance on the road transport sector, but also asked if any other potentially viable sectors could at least be highlighted in this pre-feasibility study.

Natural gas, being the cleanest fossil fuel, has a rapidly growing market share in 80+ countries worldwide in the road transport sector. Currently there are estimated 17 million + natural gas vehicles in operation worldwide. However, to put things in perspective, this equates to less than 2% of the total market of all motor vehicles within these countries. Gasoline and diesel remain the dominant players. The gas market share in the vehicle sector is greater than 5% of all vehicles in around 14 countries.

The use of gas in the Manufacturing and Commercial sectors worldwide mostly depends on the extent of natural gas pipeline networks. When available for these sectors natural gas is popular because it is clean burning, easy to operate and control, responsive to customer requirements and often competitively priced.

This pre-feasibility study assumes that, in the short to medium term, internal gas pipeline systems would not be economically justified. For the purpose of this study we have defined short to medium term as 15 years and it has been assumed that natural gas clients would be limited to power stations, together with larger scale manufacturing and commercial establishments and refuelling stations (public and private depot based private vehicle fleet installations) that could receive bulk deliveries of gas by an alternative distribution method (via road tanker).

2.2 Transport Technology

2.2.1 LNG and CNG (Compressed Natural Gas) distribution technology

As stated above it is assumed that at least in the short to medium term a comprehensive gas pipeline system would not be economically justified in a warm and, relatively speaking, low density island such as Mauritius. The vast majority of countries that have comprehensive pipeline networks both have a need for space heating for winter periods and are relatively densely populated.

For Mauritius the options would therefore theoretically have involved either the distribution of LNG or CNG by road tanker to larger clients in the manufacturing and commercial sectors and to gas refueling stations for motor vehicles. However as this pre-feasibility study has developed it has been decided that a floating LNG terminal would be the recommended way forward due to the limited overall demand for gas, and the configuration proposed would involve the delivery to the shore of 40-45 bar pipeline gas and NOT LNG.

Consequently the proposed solution for the road transport and manufacturing and commercial sectors involves the compression of the pipeline gas to 250 bar at a compression site fed by the incoming gas pipeline from offshore and the transportation and selling of compressed gas.

For the purpose of this pre-feasibility report we have left in the references to LNG technology appertaining to these sectors for information only.

a. LNG distribution

The distribution of LNG would involve the loading of specialist bulk cryogenic trailers with LNG at the main LNG importation terminal and the transportation via road to individual demand points within the island. A typical fully laden 40 tonne truck / trailer combination would have the capacity to transport some 18,000 kg of LNG, broadly comparable with a typical bulk petroleum transporter. Such a trailer could supply up to 8-10 demand points per day.

Exhibit 2-3: Examples of LNG trailer and CNG trailer

b. CNG distribution

The preferred alternative for Mauritius to distributing LNG would be to distribute CNG. This would involve the incoming pipeline gas being compressed to 250 bar. The CNG would then be loaded onto bulk CNG trailers and transported to individual demand points.

In this case a typical 40 tonne truck / trailer combination would be able to deliver 3840 kg (5,200 m3) of compressed gas, comparable to roughly 1/5 of the capacity of a similarly sized petroleum or LNG transporter. It is quite common for CNG trailers of this type to be “switched”, i.e. a full trailer is delivered and an empty trailer returned for re-filling.

CNG bulk transportation operational costs are higher than LNG transportation because more trailers and deliveries are required due to the 1:5 differential of energy transported.

2.2.2 Refuelling station technology

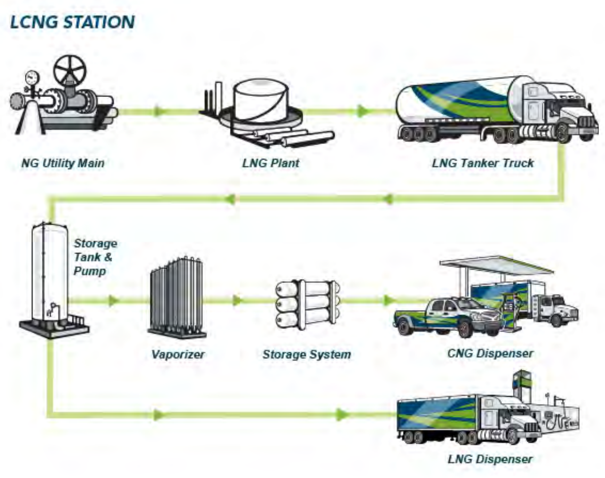
a. LNG / LCNG stations

LNG stations typically include off loading facilities, LNG cryogenic storage vessels, a control system and a number of dispensers that dispense LNG directly into LNG vehicles equipped with cryogenic LNG storage cylinders.

A LCNG station can cater for vehicles equipped with LNG storage cylinders (LNG vehicles) AND vehicles equipped with CNG storage cylinders (CNG vehicles), or CNG vehicles only if no LNG vehicles exist in the market place. In addition to the facilities listed above for a LNG station, a LCNG station also has an onsite vaporiser to transform all or some of the LNG to CNG, some CNG storage and a number of CNG dispensers, with or without some LNG dispensers depending whether there is a need for them.

At this pre-feasibility stage indications are that the equipment required for a LCNG station has a significantly higher capital cost than for a CNG station fed by bulk CNG transporters.

Exhibit 2-4: Example of LCNG station system



b. CNG stations

When CNG is delivered, the CNG storage trailer is often "switched" and the empty trailer is removed from site and returned to the central facilities for refilling. A CNG station will comprise a CNG offloading facility, space for the trailer, a limited storage facility, a CNG pressure booster facility and some dispensers.

Exhibit 2-5: Example of CNG trailer and station

2.2.3 Natural Gas Vehicle (NGV) technology

NGV technology is well established. The industry has an excellent safety record and NGVs are environmentally friendly and can be very economical to use.

For motor vehicles, by far the most common form of natural gas used is CNG. In order to get a sufficient supply of energy on-board a vehicle, gas is compressed up to 250 bar pressure and stored on vehicles at typically 220 bar.

This pressure requires very robust steel or composite storage cylinders on-board the vehicle. A disadvantage of CNG when compared to gasoline or diesel is the storage space required and the weight of the storage facilities.

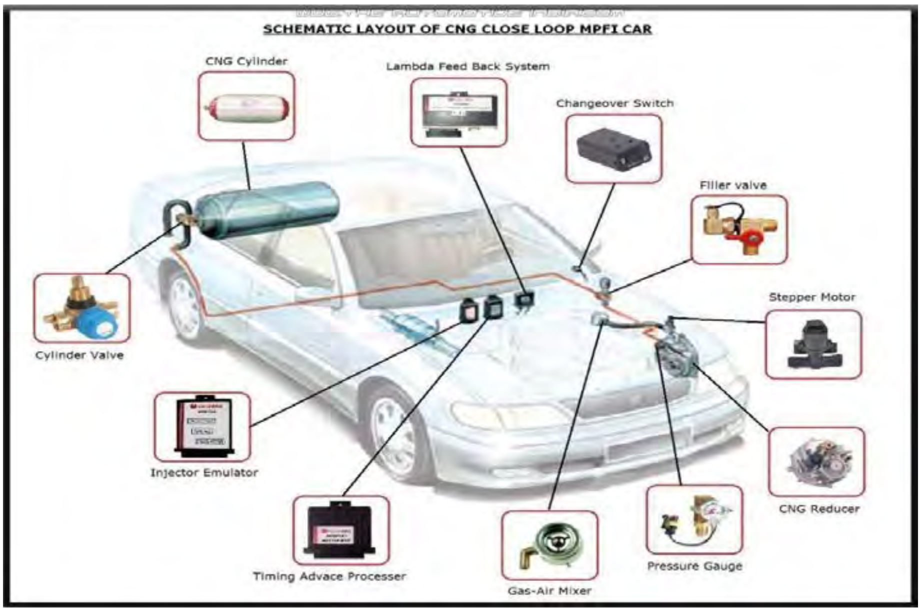
CNG is suited to a wide range of vehicles, including passenger cars, taxis, vans, minibuses, buses and trucks.

LNG has energy content more similar to petrol and diesel and thus weight and space is not generally an issue. However LNG vehicles require cryogenic storage which is relatively costly. LNG tends not to be used in smaller, less energy consuming vehicles and is used mostly in long distance, heavy duty and fuel consuming trucks. A more recent development has been the use of LNG in busses, primarily in China.

a. Conversion technologies

For both CNG and LNG vehicles technology is available to convert a wide range of existing vehicles fuelled by diesel or gasoline to gas. For gasoline powered vehicles by far the most common conversion is to bi-fuel (petrol or CNG).

Exhibit 2-6: Schematic of CNG technology conversion



CNG storage, a filling point, gas management system, safety valves and interconnecting pipe work are added to the existing vehicle and the driver can chose between using CNG or petrol. Relatively speaking the conversion of gasoline vehicles is not a major cost but specialist engineering skills are required to do the job properly. This type of conversion should not take more than 1 day to complete.

For existing larger diesel vehicles the options are to convert to dual fuel (diesel and CNG or LNG) or to dedicated gas only. The choice between LNG and CNG will depend on the availability of the 2 fuels in the local market place and any space or weight limitations on the vehicle that potentially could preclude the CNG option. Some larger diesel vehicles have their existing engines completely replaced by a new gas engine, (repowering). The conversion or repowering of a heavy duty bus or truck is a major modification that requires specialist engineering skills, a good budget and the vehicle needs to be taken out of service for a number of days.

Exhibit 2-7: Example of LNG cryogenic storage tank

b. New OEM vehicles

In addition to the conversion of existing vehicles, many vehicle OEMs now offer brand new gas models from their factories. The advantage of designing in gas into a new vehicle is that modifications can be made to the chassis / body so that gas storage tanks can be added to the vehicle without any loss of usable space on-board.

Exhibit 2-8: Examples of OEM gas vehicles

Normally, for smaller vehicles the main fuel on-board will be CNG but the OEM will retain a smaller storage system for gasoline. If the vehicle runs out of CNG the vehicle will still be able to operate on gasoline only.

When it comes to larger buses and trucks that traditionally would use a diesel engine, the most common product available from OEMs is the dedicated (CNG only) vehicle. Dedicated CNG heavy duty vehicles usually will meet or exceed the Euro 5 emissions level and they have proved to operate very well, particularly in busy urban environments close to their refuelling facility and where toxic emissions from traditionally fuelled transport are at their highest.

Exhibit 2-9: Iveco refuse truck Madrid & Scania CNG bus

Variants to the dedicated CNG “norm” include LNG vehicles and dual fuel vehicles. As stated earlier the advantage of LNG over CNG is all to do with the relative weight and space required for the 2 fuels. Because of this particular advantage of LNG, some fleet operators will opt for new LNG vehicles when maximum payloads are an issue or when the vehicle needs to carry more fuel on-board to be able to complete longer journeys. Dedicated CNG or LNG engines have spark ignition and different performance characteristics to diesel engines.

A limited number of new dual fuel vehicles can be provided by OEMs in cooperation with specialist dual fuel technology vendors. Dual fuel is a combination of diesel and gas and a key advantage of dual fuel over dedicated gas is that if the gas on-board runs out the vehicle can operate 100% on diesel. As such dual fuel is particularly suited to long distance, high fuel consuming trucks which require a high volume of fuel on-board.

Exhibit 2-10: Volvo dual fuel truck - UK

Dual fuel engines rely on compression ignition and perform exactly the same as a traditional diesel engine. From an emissions standpoint dual fuel performs better on the open road when the fuel most predominantly used is gas, but in busy urban environments, when the engine idles more, more diesel is used and the environmental performance is thus more like that of a diesel engine.

c. Gaps in NGV technology

There are still limited options in the market place for the economic conversion of smaller diesel engines, used for example in minibuses, vans and passenger cars. The only real solution currently is to trade the existing vehicle in and to buy a new bi-fuel gas / petrol vehicle.

It is also very challenging from an engineering and economics point of view to operate 2 wheelers (motor bikes, scooters and mopeds) on CNG or LNG. However, many 3 wheeler "tuk tuks" (motor rickshaws) in Southern and East Asia now operate very successfully on CNG.

2.3 World-wide Market Overview and Lessons Learned

Although the advent of NGVs took place in Italy as far back as during the 2nd World War, market development has taken place for the vast majority of participating countries since the 1970s – 1990's, with most growth taking place in many countries since the turn of the millennium.

Exhibit 2-11, produced by the European Natural Gas Vehicle Association, shows how the overall market has grown to date and their forecast for the future as the world continues to search for viable alternatives to gasoline and diesel.

Exhibit 2-11: NGV market share

Of the 80+ participating countries, the countries with currently the most NGVs are shown in Exhibit 2-12.

Exhibit 2-12: Largest NGV markets world-wide

Country	NGVs (millions)	NGV % market share in country
Iran	3.300	27.0
Pakistan	2.790	79.7
Argentina	2.244	17.5
Brazil	1.744	5.0
China	1.577	1.5
India	1.500	3.5
Italy	0.846	2.1
Sub Total	**14.001**	
Others	3.729	
Total	**17.730**	**1.6**

Exhibit 2-13 lists the 14 countries where the market share of NGVs exceeds 5% of the total vehicle population.

Exhibit 2-13: Leading NGV market shares worldwide

Country	NGVs (000s)	% NGV market share in country
Pakistan	2,790	79.7
Bangladesh	182	62
Armenia	244	55
Bolivia	255	28
Iran	3,300	27
Uzbekistan	450	26
Argentina	2,244	17.5
Colombia	450	15
Peru	158	10
Myanmar	30	8
Egypt	194	5
Brazil	1,744	5
Ukraine	388	5
Tajikistan	11	5

a. Government policy in supporting NGV programmes

National, and in many cases city governments, have supported the development of NGV growth for a variety of reasons, including:

- The reduction of greenhouse gases – NGVs can reduce greenhouse gas emissions by typically 25%

- The reduction of city centre pollution and the resulting negative impact on public health caused by road transport – NGVs emit significantly lower toxic emissions such as NOx, SO2 and particulate matter.
- To demonstrate commitment to cleaner air during a bid to host a major sporting event (e.g. the Soccer World Cup and the Olympics)
- To improve the internal and international reputation of the government as a responsible, environmentally concerned country / city
- To lessen dependency on imported oil products and diversify supply risk
- To create a new industry and new jobs
- To encourage the introduction of a lower cost fuel in the transport sector

An additional potential driver for Mauritius is that a successful NGV sector could help build the case for the importation of LNG which may not be viable based on demand from the power sector alone.

Government policy to support the growth of the NGV sector can be divided into various types of legislation. This can include legislation that encourages vehicle owners to convert to gas, and legislation that forces some vehicle fleets / types to convert to this cleaner fuel. Common examples of Government policy include:

- The application of lower taxes and duties on the cost of the fuel to strengthen the economic case for NGVs.
- The application of lower taxes and duties on the cost of gas conversions and new gas vehicles, again to strengthen the economic case.
- The making available of government grants against the cost of conversions or the added cost of new gas vehicles over and above the cost of traditionally fuelled vehicles.
- The application of lower taxes or making grants available to encourage potential refueling station developers to create a suitably comprehensive refueling infrastructure to satisfy local demand
- The commitment to convert government vehicle fleets to gas to demonstrate leadership by example
- The requirement that certain city center fleets (e.g. public bus service, refuse collection fleets, taxis etc.) convert to gas to clean up on toxic pollution
- The exemption of NGVs from city center vehicle pollution taxes / levies
- Allowing NGVs to use traffic lanes otherwise used only by public transport and emergency vehicles.

In terms of justifying pro – NGV policies and legislation it is quite common practice for National and City governments to justify such support based on the strategic benefits that cleaner vehicles will create. For example many governments have followed methodologies developed by bodies such as the World Health Organisation; which estimate the economic cost to society of heavily polluting vehicles and calculate the reduction in such costs brought about by their cleaner counterparts.

Several studies have been carried out that calculate the impact of long term heart, respiratory and cancer related illnesses on public health costs and loss of economic productivity in the workplace. As a result of such studies, Governments have made grants or tax breaks available to encourage new technologies that will reduce such costs and improve industrial output.

2.4 Transport Assessment Specific to Mauritius

Based on reasonably promising preliminary scoping economics as will be described in Section 2.5 and on lessons learnt in other countries it is possible to estimate how a Natural Gas Vehicle market could develop in Mauritius.

From the worldwide data provided in Section 2.3 a few conclusions can be made which impact on a market growth prediction for Mauritius:

- Only in 14 countries worldwide has the gas market share in the transport sector to date exceeded 5%.
- Only 8 countries have reached or exceeded a gas market share of 15%
- In general markets take a number of years to get established due to the fact that most individuals and companies will prefer to see this new technology proven in country before committing their own vehicles to gas.
- Market growth can be stimulated and speeded up if National or Local Governments impose regulations requiring certain types of fleets to convert to this cleaner fuel and the economic proposition is positive to end users..

Based on this experience it is possible to analyse the Mauritian vehicle market sector by vehicle type and estimate how many of each vehicle type could convert to gas in the medium term (15 years). From this number and type of vehicles it is then possible to build up an annual gas usage / demand based on assumptions of annual km and fuel efficiencies achieved elsewhere by similar gas vehicles. For the purpose of this forecast it has been assumed that gas vehicles would travel between 40-50,000 km per annum, reasonable for all the commercial vehicles listed and for higher mileage company cars / pickups and vans where the motivation to convert to gas would be higher due to the greater weekly fuel savings which would be enjoyed.

Exhibit 2-14: Mauritius Vehicle Population

Vehicle type	Number 2013	Gas share (%)	NGV's	km/annum	km/m3	m3
Cars (incl heavy motor cars & taxis)	158442	12.5	19805	40000	11	72019091
Dual purpose vehicles / pickups	50746	12.5	6343	50000	9	35240278
Vans	26564	12.5	3321	50000	9	18447222
Buses	2958	40.0	1183	40000	2.25	21034667
Lorries and trucks	14023	8.5	1192	40000	3.6	13243944
Prime movers (i.e. tractor)	707	8.5	60	40000	3.6	667722
Total	253440		31904			160652924
					million m^3	161
					Million Tonnes of LNG (1 ton 1379 m^3)	0.116

From the table it can be seen that for cars, dual purpose vehicles, pick ups, and vans a 12.5% medium term market share has been assumed. For lorries, trucks and prime movers a 8.5% share has been assumed, lower due to the higher costs associated with converting to gas. (see paragraph 2.5 for rationale). For buses a 40% market share has been assumed, on the basis that the government, like many others worldwide, might target this sector in an attempt to reduce urban pollution.

It should be noted that none of the following vehicle types are considered suitable for conversion to gas:

- Motor cycles
- Motor cycles
- Auto cycles
- Tractors
- Dumpers
- Trailers
- Road Rollers

Finally it is possible to estimate how quickly this medium term market could be developed, again based on growth patterns achieved elsewhere and this will provide us with an estimate of LNG needed from Year 1 to year 15. In this regard, based on the growth of the vehicle market during the past 10 years a 2% per annum growth rate was assumed going forward.

Estimated LNG volumes for the road transport sector for low, base and high cases are as follows:

Exhibit 2-15: Estimated LNG volumes for the transport sector

Case	LNG MTPA
Low Case	0.093
Base Case	0.116
High Case	0.140

The estimated build-up of demand, year by year is shown in Exhibit 6-13.

2.5 Cost Estimates & Scoping Economics

This section looks at preliminary scoping economics of a potential NGV market both from the perspective of vehicle owners (e.g. bus, truck, van, passenger car owners) and the shareholders that would be involved in making a suitable gas supply chain available, from the floating LNG terminal right through to the dispensing of CNG at refuelling stations.

Indicative capital and operating cost estimates are provided for a suitable refuelling infrastructure and for a variety of gas vehicle types.

The content of this section is based on a very short visit to Mauritius and many assumptions that have needed to be made at this stage to arrive at preliminary conclusions. The results will therefore have the potential to change substantially should it be decided as a result of this Pre-Feasibility Study to proceed in more detail with a full Feasibility Study. However these preliminary conclusions will at least give an indication of whether a NGV market has the potential to be developed on an economically viable basis.

2.5.1 End user economics

Based on the short visit to Mauritius a number of key fleets were identified which could be considered suitable from the fleet operator's and the government's point of view for conversion to environmentally friendly gas.

The Public Bus Service

Buses use large volumes of diesel and are often a key polluter in urban environments. Consequently the Mauritius government could follow the example of many other governments around the world and make natural gas the fuel of choice throughout the public bus service. A modernisation and "cleaning up" of the bus service would bring significant environmental and image benefits to the government.

The tourism industry and car rental fleets

Mauritius depends heavily on its tourism industry and again it is suggested that this sector of the transport industry could be targeted for a switch to natural gas. Again environmental benefits would be gained, and a very powerful "eco" message could to promoted to all international visitors, that Mauritius is serious about maintaining and improving upon air quality throughout the island. This would create excellent reputational / image benefits for the Mauritian government throughout the world.

Key Government fleets

Many Governments lead by example when embarking on natural gas vehicle policy and ensure that a good proportion of their own vehicles convert to gas. Over and above ensuring that the public bus service operated primarily on gas, the most appropriate government owned fleet identified during the brief visit to Mauritius was potentially the police service fleet, a large fleet of relatively high mileage vehicles.

Trucks and commercial fleets in general

Higher mileage commercial fleets are key targets for NGV programmes in that the vehicles can be highly polluting and have higher than average fuel consumptions which help the "pay back" economics of converting to gas.

Key assumptions in arriving at end user economics / “payback periods”

1. When comparing a m^3 of CNG with a litre of petrol, gas is approximately 10% more efficient than petrol.
2. When comparing a m^3 of CNG with a litre of diesel gas is approximately 10% less efficient than diesel.
3. The cost of converting a traditionally fuelled vehicle to gas, or the additional cost of a new gas vehicle over and above an equivalent traditionally fuelled vehicle has been assumed as follows, based on average prices in other countries:
    a. Bus and truck – US$35,000 to US$48,000
    b. Minibus – US$5,000 to US$7,500
    c. Passenger car, taxi, police car – US$1,500 to US$3,000
4. CNG sales prices of Rs31.00 per m^3 for buses and trucks which traditionally have only been able to use diesel and Rs40.00 per m^3 for all other vehicles are proposed, based on the following assumptions:
    a. The sales prices are inclusive of 15% VAT.
    b. The investment in the gas chain from port to CNG dispenser is made primarily by a specialist CNG trading company. A retail margin of Rs2.00 per m^3 sold is paid to the retailer (if applicable) by the specialist CNG trading company to serve the fuel on a daily basis from his site.
    c. As is the case with LPG Autogas, CNG would need, it appears at this stage, to be sold exempt of Excise Duty, justified on the lower environmental impact of NGVs when compared with traditionally fuelled LPG vehicles.
    d. All other minor taxes and levies that apply to petrol and diesel would apply to the CNG prices.
    e. For reasonable payback periods to be achievable for buses and trucks Government would need to subsidize each bus or truck gas conversion or new CNG vehicle at an estimated preliminary value of US$20-30,000 per vehicle. These subsidies would be offset by the current rebate of Rs4.00/liter diesel enjoyed by public bus operators being withdrawn.
    f. The proposed differential sales pricing for CNG would be required for CNG to be competitive against diesel used in larger vehicles and parts of the diesel sector could be targeted by government for mandated (forced) conversion to gas on environmental grounds. As CNG buses and trucks are generally fed via larger diameter gas pump “nozzles” abuse of the proposed lower price for larger vehicles by owners of smaller vehicles would be controlled in that it would be physically impossible for smaller vehicles to be fed via these larger nozzles. It is felt important that the diesel sector is targeted as well as the petrol sector in the dual interest of improving the environment / image of Mauritius and creating the overall critical mass of demand for LNG.
    g. Any differences in maintenance costs and residual values have been ignored in the calculation of payback periods as they are fairly insignificant.

5. Based on the above assumptions and the annual mileages shown below, payback periods and annual fuel savings would be as follows, for the lower and higher conversion costs set out above:

Vehicle type	Annual km	Payback period	Annual savings
Bus – diesel	40,000	2.9-3.4 years	Rs 157,600
Truck – diesel	40,000	4.0-4.8 years	Rs 112,570
Pick up – petrol	50,000	0.4-0.9 years	Rs 101,000
Company car, van – petrol	40,000	0.7-1.4 years	Rs 65,000

2.5.2 CNG Trading Company economics

As stated previously in the report the proposed technical configuration for Mauritius is a floating LNG terminal which would deliver regassified gas via pipeline to the shore.

As it happens based on the preliminary information provided by potential suppliers of both CNG and LCNG equipment the transporting and serving of CNG appears to be considerably more cost effective than the cost of transporting and serving of LCNG.

A scenario was developed for the delivery of CNG assuming an initial 8 refuelling stations being built and a 10 year operational period was assumed for the purpose of arriving at economic returns. A larger business supplying more stations longer term would benefit from some economies of scale and hence it could be assumed that returns could improve on this initial scenario.

Base Case Scoping economics for an initial 8 station scenario provided returns based on the following:

1. Capex – a total of US$7.3 million, US$1.3 million at the terminal, (excluding land cost and gas and electricity connection costs), US$4 million on delivery trucks and trailers and US$2 million at the 8 stations (i.e.US$250,000 per station).
2. Opex – an annual Opex of US$1.5 million to cover the cost of Salaries & Wages, the maintenance of equipment, electricity used by the compression station, insurance, vehicle fuel and general administration expenses.
3. A Base Case LNG landed price ranging from US$ 13-19 / mmbtu
4. A Base Case LNG regassification tariff ranging from US$ 11-19 / mmbtu determined on an annual basis primarily on the estimated throughput for that year.
5. Rs 2 / m^3 sold paid to the retailer
6. Zero excise duty paid to Government
7. Annual sales of 17.3 million m^3 from the 8 stations, or 180,000 m^3 per station per month at prices of Rs 31.00 / m3 and Rs40.00/m^3 including VAT.

Based on all the above information the trading company would make a Base Case 20% nominal IRR, considered to be in the right range for this type of investment / activity. The assumed CNG sales prices provide reasonably attractive payback periods (with the aid of the US$20-30,000 per bus or truck) to attract the number of vehicles and the estimated LNG volumes as set out in Section 2.4.

It should be emphasized that if High Case LNG volumes from the power and other sectors could be assumed / achieved this would strongly influence the economics of the entire project as is discussed further in the report. As far as the transport sector is concerned this could potentially have the impact of vehicle subsidies being reduced or a level of excise duty being levied on the sale of CNG, but it would also depend on a determined long term pro gas policy by government being committed to thus ensuring that higher volumes were actually achieved.

2.6 Other Sectors – Manufacturing & Commercial

2.6.1 Gas receiving technology for manufacturing / commercial clients

a. LNG

Had LNG been an option, Manufacturing or Commercial clients would have needed LNG off loading, permanent storage and vaporising facilities to take the gas from its LNG state to a low pressure gaseous state suited to the client's gas burning equipment.

b. CNG

A client receiving bulk supplies of CNG would require off loading and pressure reduction facilities. As in the case of vehicle refilling stations, the capital cost of CNG receiving facilities for manufacturing / commercial clients would be significantly less expensive than the cost of LNG receiving facilities.

2.6.2 Market potential

Time in country did not permit the manufacturing or commercial sectors to be analysed and in fact such analysis would have been outside the scope of the pre-feasibility study. No economics have been carried out for these sectors at this stage. However the sectors were identified as having some larger potential clients which could potentially be served by bulk gas transporters.

A similar “top down” approach has been taken as was taken for the transport sector in assessing the potential demand from these 2 sectors. Based on recent history it was assumed that the combined manufacturing / commercial demand would not grow going forward. It was assumed that because of the relative cost of LNG, it would not displace lower priced bagasse, wood, coal and charcoal. A medium term (15 years) base case gas market share of 5% has been assumed in each sector, restricted due to the fact that gas consumers would need to have relatively large demands to justify cost effective bulk delivery of CNG by truck.

A table indicating how this demand would grow year by year is shown in Exhibit 6-13.

2.7 Discussion and Recommendations

Subject to the findings of a more detailed feasibility study on the use of gas in the transportation, manufacturing and commercial sectors, it appears at this stage that if a LNG importation project could be justified or "anchored" on the economics and commitment from the power sector, overall gas demand could be gradually expanded on economic grounds over an initial 15 year period from these sectors.

On the other hand it is unlikely that potential LNG suppliers or financial institutions would include any potential demand from these sectors in arriving at initial supply contracts and project funding.

Exhibit 2-16 shows how the case for the road transportation, manufacturing and commercial sectors could be developed further should CEB decide to pursue further the LNG importation project.

Exhibit 2-16: Draft Schedule for implementation of road transportation, manufacturing and commercial sectors

Mauritius Transport Implementation Plan Draft | Baseline 1 | 19-Mar-14 13:31

Activity ID	Activity Name	Start	Finish	Original Duration
	Mauritius Transport Implementation Plan Draft	30-Oct-14	12-Jun-19	1204
	Project Precursors	30-Oct-14	01-Dec-15	283
PP.1000	FEED And SOW Complete	04-Nov-14		0
PP.1100	Decission on structure of new gas industry and on key policies,	04-Nov-14	27-Jan-15	60
PP.1200	Selection of vehicle refuelling sites and key manufacturing and commercial clients	30-Dec-14	30-Jun-15	130
PP.1300	Market development and awareness campaign, signing of preliminary MOUs with key clients	02-Dec-14	29-Jun-15	150

[redacted]

Activity ID	Activity Name	Start	Finish	Original Duration
PP.1400	Contribution towards port / terminal scope of work / FEED	13-Jan-15	14-Jul-15	130
PP.1500	Permitting and approvals	30-Oct-14	29-Jul-15	194
PP.1600	Signing of gas sales contracts with key clients	03-Jun-15	01-Dec-15	129
	Tender & Approvals	21-Oct-15	15-Dec-16	301
T&A.1000	Preparation and floating of tenders for LNG / CNG infrastructure equipment suppliers	21-Oct-15	19-Apr-16	129
T&A.1100	Preparation and floating of tenders for vehicle conversion equipment suppliers	21-Oct-15	19-Apr-16	129
T&A.1200	Preparation and floating of tenders for new CNG vehicles from OEMs	21-Oct-15	19-Apr-16	129
T&A.1300	Preparation and floating of tenders for manufacturing / commercial equipment suppliers	21-Oct-15	19-Apr-16	129
T&A.1310	Identification and selection of vehicle conversion companies	21-Oct-15	19-Apr-16	129
T&A.1320	Identification of manufacturing and commercial equipment installers	21-Oct-15	19-Apr-16	129
T&A.1330	Award of tenders to selected suppliers	19-Apr-16	15-Dec-16	172
	Procurement	14-Dec-16	12-Mar-18	323

[redacted]

Activity ID	Activity Name	Start	Finish	Original Duration
A1140	Procurement of CNG / LNG transportation trucks & trailers	15-Mar-17	12-Mar-18	258
A1150	Procurement of transport refuelling stations, manufacturing and commercial facilities	14-Dec-16	12-Mar-18	323
	Construction	14-Feb-18	13-May-19	323
A1160	Construction Terminals	14-Feb-18	13-May-19	323
A1170	Construction of transport refuelling stations, manufacturing and commercial facilities	14-Feb-18	13-May-19	323
	Commissioning	04-Mar-19	27-May-19	60
PRECOM.·	Ready for Vehicle conversion	06-May-19	13-May-19	5

3. LNG INFRASTRUCTURE ASSESSMENT

3.1 Introduction

LNG Import Terminal infrastructure assessment for a country and/or region requires critical assessment of several factors such as:

- Establishing current and projected LNG demand
- LNG supply chain and navigational assessment
- Defining objectives of setting up the LNG import Terminal
- Site suitability, accessibility,
- Identification of constraints: port, fisheries statutory concerns
- Appropriate Marine Exclusion zones, Safety zones and surroundings
- Metocean, Bathymetric, geophysical, geotechnical, seismic and cyclonic data
- Opportunities for Ancillary Services.

This Section of the Report addresses the LNG related infrastructure requirements and the technologies should an LNG terminal prove viable in Mauritius.

3.2 LNG Re-Gasification Terminal Sizing

The projected demand for LNG in Mauritius has been assumed to be 1 million tons per annum (1 MTPA). This is equivalent to:

Exhibit 3-1: Equivalent units for 1MTPA LNG

mtpa	LNG t/h	LNG m3/h	NG Nm3/h	NG Sm3/h	NG BSMY	NG mmscfd	BBtud
1	114	250	145,379	153,367	1.34	130	142

This is a capacity of a “small scale” LNG terminal used to feed the 600- 1000 MW power plants. It is well understood and noted that even this capacity of 1 MTPA may be too large considering the presently projected demand of 0.3 MTPA demand in Mauritius, however to have a chance to create sufficient economies of scale to lower unit cost for the import terminal this capacity has been considered as a basis for this study. As further study, Mauritius may take steps to conduct a market study on how the demand for LNG could be raised. One idea may be for Mauritius to become a LNG hub; however it is uncertain of this will have major impact as there are no major consumers in the vicinity[11]. Maybe if Mauritius worked with Reunion to also put in LNG facilities, then Mauritius could become a hub and Reunion a spoke, they could possibly have enough LNG to share the 1 MTPA capacity in future. Another prospect for LNG Regas requirement potential increase may be if

[11] Rodrigues – there are only 30,000 people on that island compared with 1.3 million on Mauritius and it has a power generation capacity of 11MW, it is 600km from Port Louis. Reunion has a population of 835,000 people and a higher GPD per head than Mauritius, but it is a separate country, French speaking and about 200 km away.- too far for a subsea pipeline.

industrialization takes place in future, specifically of Refining and Petrochemical sector. However, further discussion on this is beyond the scope of this report.

In view of above it is suggested that the basic infrastructure for LNG is kept at 1MTPA. The LNG on the FSRU may be regasified according to the demand and increased as the demand grows.

3.3 LNG Storage Requirements

Historically, Mauritius has been witnessing cyclonic conditions. Based on the metocean and environmental data which may cause delays in LNGC berthing, it is recommended to keep a reserve of at least 6 days of LNG to ensure uninterrupted supply of regasified LNG. Taking into account, 6 days of back up LNG Storage requirements, the LNG storage requirement for a 1 MTPA LNG Import Terminal is tabulated in Exhibit 3-2.

Exhibit 3-2: LNG storage requirement for a 1 MTPA LNG Import Terminal

LNG Storage Capacity (m^3)	No. of days' LNG supply based on Peak Send-out rate of 1 MTPA
80,000	~7
125,000	~14
180,000	~23

Mauritius is far from any source of LNG. Refer to Section 6.4 for potential supply sources. It is noted that the LNGC will take a significant number of days from after LNG loading to be available for berthing and unloading at Port Louis.

With above considerations, LNG storage capacity of 170,000 to 180,000 m^3 has been recommended[12].

WorleyParsons has complied a database of FSRU's capacity; most of the FSRUs are in the capacity range of 120,000 to 173,000 m^3 and keeping the most commonly used FSRU and the LNG storage requirements depending on turnaround, 173,000 m^3 FSRU has been selected for this study.

[12] Note: it is not cost effective to store LNG for long period of time given the fact that LNG is stored at cryogenic temperatures of minus 160 degrees C and with the insulation that is normally provided on Moss or Membrane tanks, do result in Boil off Gas of 0.15% per day. This Boil-off Gas is either compressed to about 6 barg or used as fuel in FSRU or is reliquefied. Either of these operations are high in OPEX and are not cost effective. However, given that the demand of LNG in Mauritius is too low and given the fact that small LNG ships are not practical because of the long sailing distance to LNG supply sources, we do not see any way by which long time storage of LNG can be avoided. May be part trans-shipment from a LNGC carrier, could reduce the LNG storage duration, but this will require arrangement with LNG suppliers or spot cargo.

3.4 LNG Re-Gasification Terminal & Storage Technology Overview

Depending upon Environmental considerations, metocean considerations and several other factors listed in Section 3.1, LNG Import Terminals are either:

- Onshore
- Nearshore or
- Offshore

Each of these is described in the sections below. As per the request from CEB, general background information around various available technologies is also supplied; recommendations are then provided for the preferred technology selection for Mauritius.

3.4.1 Onshore

Onshore LNG Terminals are most common in the industry. Onshore Terminals are normally of 3 MTPA capacity or larger and where provision for future expansion is to be kept. Singapore LNG Terminal is one such example shown in Exhibit 3-3.

Exhibit 3-3 Shore based LNG terminal (Singapore LNG)

Examples exist of small onshore LNG Terminals feeding 600 MW power plants. One example is The Dominican Republic LNG terminal (Exhibit 3-4) that can hold 160,000 cubic meters of LNG, and the country imports 120,000 cubic meters of LNG once every four weeks, which is enough to keep its three natural gas power plants, with a combined capacity of 600 MW, fully operational as the country's primary source of base load power. Even though the Dominican Republic's LNG supply is on the very low end of the industry standard range, it still manages to fuel greater than 4,000 GWh of power generation per year, or around 30 percent of the country's total.

Exhibit 3-4 Dominican Republic LNG terminal

Description:	• This configuration is based on an onshore LNG storage facility connected to an offshore berth through a steel trestle supporting a cryogenic piperack. • The trestle and jetty structure can be constructed using either: o Steel piles installed on site o Pre-fabricated jacket structures constructed onshore. The jacket structures are then floated out and installed on site • The jetty includes mooring/fendering structures to moor the LNGC, and loading arms for LNG transfers. A cryogenic piperack installed on the trestle will be used to carry the natural gas in its liquefied state to the onshore storage unit. • The on shore plant, including storage and regasification units, will have to be placed on a solid ground or piled foundations adequately protected by any cyclone induced storm and coastal flooding events.
Storage capacity:	Onshore LNG Tank: 1X160,000 m^3 to 180,000 m^3 Full containment Tanks LNGC Size: 125,000 to 150,000 m3
Water depth:	Typically 14 to 16 m
LNG transfer:	Via loading arms
Mode of operation:	LNG is transferred from the LNGC to the shore based storage unit via loading arms and cryogenic pipelines supported on a steel jetty.
Some Examples:	• Dominican Republic LNG Terminal

	• Japan - Shin Minato LNG terminal, Sendai Gas, opened 1997 • Netherlands - Gate terminal, Rotterdam, opened September 2011 • Portugal - Sines LNG Terminal, REN • Singapore LNG Terminal. Commenced commercial operation on Q2 2013

3.4.1.1 Conventional On-shore Tank Configurations

In most cases, Full Containment Tank design is selected for LNG storage. However, in some cases alternatives can be selected. The section below describes the various options and the characteristics, advantages and disadvantages of each technology. A section on selecting the appropriate tank design for Mauritius is then presented; however, it is seen in later sections that onshore storage is not the preferred option selection. The section is however presented for completeness.

a. Background

The first LNG storage tanks of the early 1960's were small (< 10,000 m^3) and were of the single containment type. The material used for the primary container was aluminium. As the demand for LNG grew through the 1970s there was a requirement for larger capacity storage tanks (circa 50,000 m^3) and the use of 9 % nickel steels replaced aluminium as the material for the primary container.

The catastrophic failure of a single containment LPG tank in Umm Said, Qatar in 1977 where the product actually overtopped the remote bund wall raised concerns within the industry over the safety of single containment LNG tanks.

Predominately led by Shell, the concepts of double containment storage tanks were developed using close proximity high bund walls, e.g. the British Gas tanks in the UK constructed in the late 1970's and early 1980's.

The development of the full containment tank was a progressive step up from the double containment tanks as the required storage capacities increased to around 100,000 m^3 in the late 1980's early 1990's and up to the present day tanks in the 140,000 to 200,000 m^3 range, with 260,000 m^3 designs in place for future terminals.

b. Tank Configurations

Single Containment

A single primary container and generally an outer shell designed and constructed so that only the primary container is required to meet the low temperature ductility requirements for storage of the product.

Exhibit 3-5: Single Containment Tank

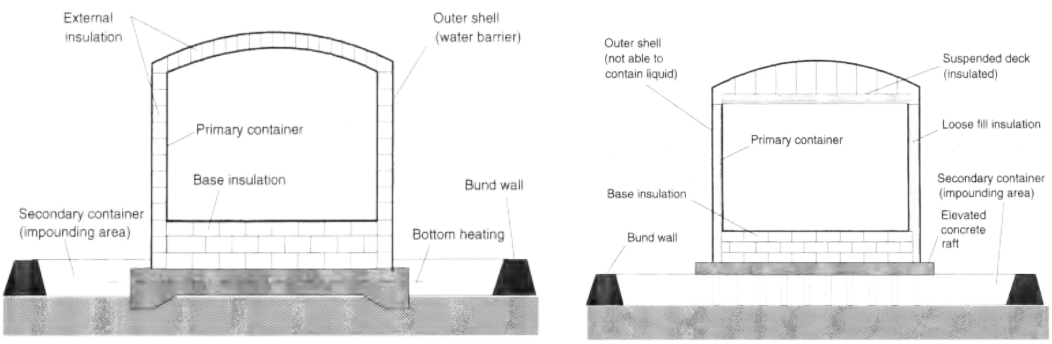


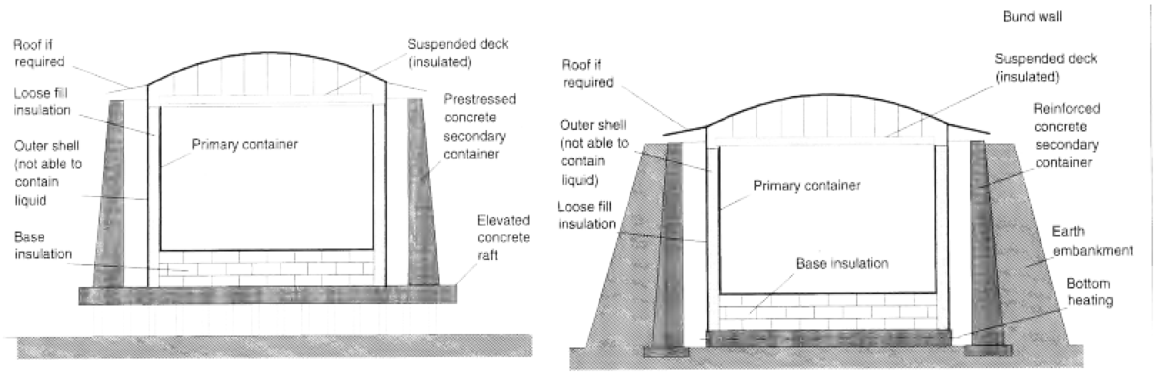
Figure H.1 Examples of single containment tanks

The outer shell (if any) of a single containment storage tank is primarily for the retention and protection of insulation and to contain the purge gas pressure, but is not designed to contain refrigerated liquid in the event of leakage from the primary container. An above ground single containment tank shall be surrounded by a bund wall to contain any leakage. Generally for this type of tank the primary container (inner tank) will be 9 % nickel steel and the outer tank will be carbon steel. Tanks of small capacity may use aluminium or stainless steel for the primary container material of construction.

Double Containment

A double containment tank is designed and constructed so that both the inner self-supporting primary container and the secondary container are capable of independently containing the refrigerated liquid stored.

Exhibit 3-6: Double Containment Tank

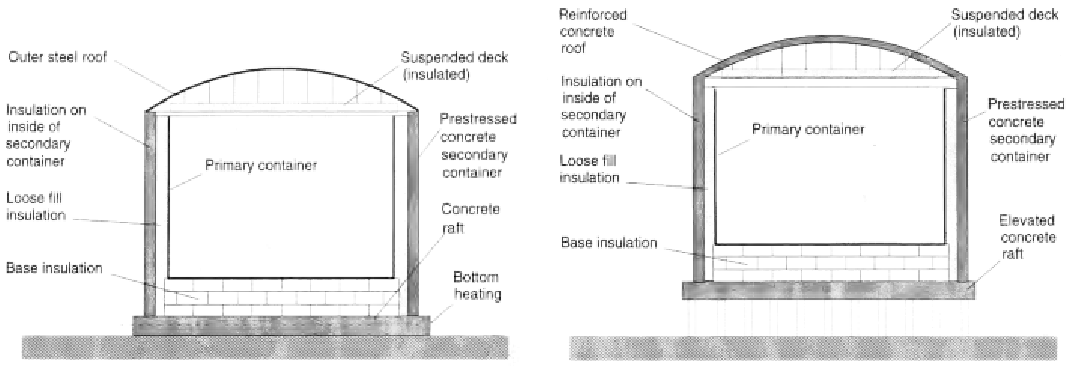


The primary container contains the refrigerated liquid under normal operating conditions. The secondary container is intended to contain any leakage of the refrigerated liquid, but it is not intended to contain any vapour resulting from this leakage. Generally for this type of tank the primary container (inner tank) will be 9 % nickel steel and the outer tank will be carbon steel. A close, high level bund wall made from concrete is provided as the secondary containment.

Full Containment

A tank designed and constructed so that both self-supporting primary container and the secondary container are capable of independently containing the refrigerated liquid stored.

Exhibit 3-7: Full Containment Tank

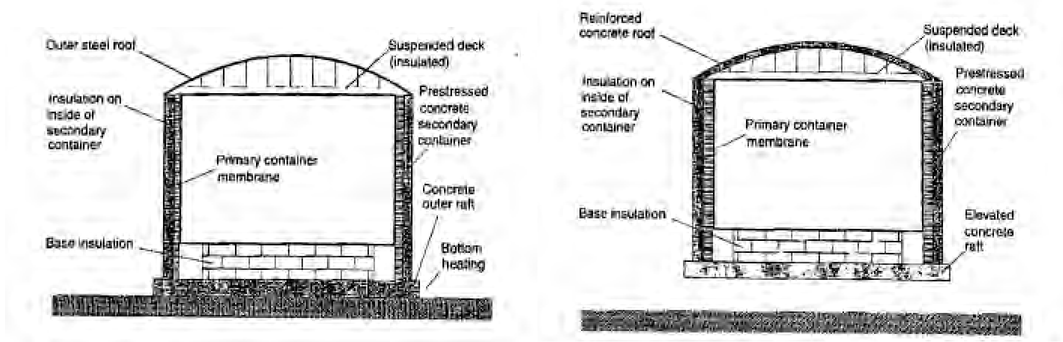


The primary container contains the refrigerated liquid under normal operating conditions. The secondary container should be 1 m to 2 m distance from the primary container. The outer roof is supported by the secondary container. The secondary container shall be capable both of containing the refrigerated liquid and of controlled venting of the vapour resulting from product leakage after a credible event. Generally for this type of tank the primary container (inner tank) will be 9 % nickel steel and the outer tank will be made from prestressed concrete providing the secondary containment. The roof is usually also made from concrete to give maximum integrity.

Membrane (Above Ground)

A membrane tank should be designed and constructed so that the primary container, constituted by a membrane, is capable of containing both the liquefied gas and its vapour under normal operating conditions and the concrete secondary container, which supports primary container, should be capable of containing all the liquefied gas stored in the primary container and of controlled venting of the vapour resulting from product leakage of the inner tank.

Exhibit 3-8: Membrane (Above Ground)

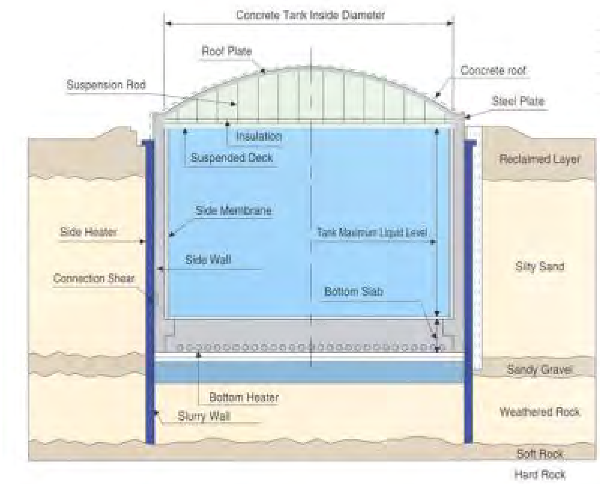


The vapour of the primary container is contained by a steel roof liner which forms with the membrane an integral gastight containment. The action of the liquefied gas acting on the primary container (the metal membrane) is transferred directly to the pre-stressed concrete secondary container through the load bearing insulation. When equipped with a concrete roof, secondary bottom and bottom corner thermal protection system this type of tank is considered full containment.

Membrane (In Ground)

This type of tank is based on Japanese design technology and has only been built in Japan, Taiwan and Korea. It uses a membrane primary containment system similar to the above ground membrane tanks built in to a concrete lined pit. This type of tank is considered as full containment.

Exhibit 3-9: Membrane (In Ground)



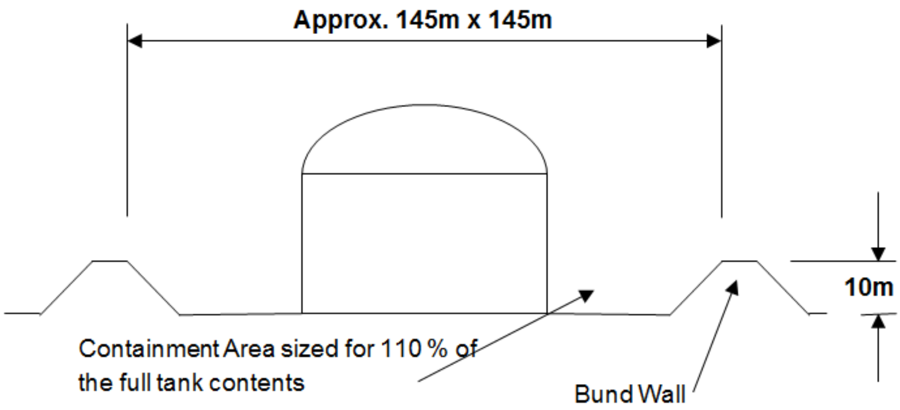
3.4.1.2 Initial Tank Screening

The selection of the tank type for a facility is normally made considering the following criteria: Safety, Environmental Impact, Cost; Schedule, Construction, Maturity of Technology, Track record in the Industry, Performance and Operability, Reliability, Plot Area.

a. Single Containment

In the event of a major leak caused by possible inner tank failure or by outlet nozzle failure the full contents of the tank would flow into the secondary containment bund area. In order to illustrate the large land usage associated with a single containment tank; as an example, the sketch below indicates the approximate dimensions of the rectangular containment bund area that would be required for a 160,000 m^3 LNG storage tank.

Exhibit 3-10: Single Containment Bund Area



Due to the large surface area of the containment bund a substantial amount of product flashing would occur giving rise to a large vapour cloud being generated. Depending on the wind conditions the cloud could spread over large distances quickly becoming a major hazard. In addition there is a risk of the vapour cloud igniting causing a large explosion.

Further risks associated with the LNG pool in the bunded area catching fire and the effects this would have on adjacent storage tanks, plant and equipment, areas outside of the site boundary and the local environment.

In summary the disadvantages of single containment LNG storage tanks include:

- The outer tank is not designed to contain LNG, therefore, a significant liquid leak through the inner could result in catastrophic failure of the outer tank in the shell to bottom area subsequently resulting in large scale spillage;
- In order to contain any potential spillage a remote bund is required. This bund is sized to contain the full contents of the tank plus a small freeboard. This gives a large surface area that could give rise large scale vapor clouds and pool fires following a major spillage. A large diameter pool fire at ground level is the cause of high radiation flux levels on adjacent equipment requiring large separation distances;
- A large plot plan area is required in order to accommodate the secondary containment bund and the minimum tank and equipment spacing required for fire protection. This has a cost impact and is not particularly suited to the plots for the sites in question;
- The outer tank is normally constructed from carbon steel, which has a lower resistance to fire, blast, impact and seismic loadings than concrete;
- Lower operating pressure compared to full containment types with concrete outer tank requiring larger capacity BOG handing package.

b. Double Containment

The secondary container for double containment tanks is located in close proximity to the primary container and is of greater height than the remote bund wall used for single containment systems. In the event of a major spillage the pool of liquid enclosed in the secondary container has a much smaller surface area than that of a remote low level bund; hence, the size of vapour cloud released is significantly smaller. This reduces the risk of large-scale vapour cloud dispersion and potential vapour cloud explosions.

In order to maintain the integrity of the tanks and reduce the possibility of major leaks or spills at nozzles, all penetrations into the tank are through the roof. Penetrations in the tank shell or bottom are not permitted.

The roof on the double containment tank is generally constructed from carbon steel and failure/collapse may be considered possible during a major fire incident leading to the potential scenario of tank burn down. The resulting fire would occur at the top of the tank wall and the magnitude of the thermal radiation flux felt at the site property lines and adjacent plant and equipment would to be evaluated. A small diameter elevated pool fire would be less damaging than the large diameter ground level fire previously discussed.

Advantages of double containment tanks over single containment tanks are:

- Reduced surface area of product enclosed in secondary container;
- Reduced flashing and size of vapour cloud generated;
- Smaller plot plan area required as remote low level bunds are unnecessary;
- Concrete outer tank offers good resistance to fire, blast and impact loads.

Disadvantages of double containment tanks compared to full containment tanks are:

- The steel roof is considered susceptible to collapse in major fire incident leading to potential tank burn down;
- Dispersion of vapor generated from a spill is not controlled;
- The steel roof not as robust as concrete roof in resisting fire, blast and impact loads;
- The steel roof is not as robust as the concrete roof in resisting the effects of LNG spillages from pipe flanges or pumps on the roof. A separate roof spillage collection system is required generally consisting of stainless steel trays and interconnecting pipe work;
- The steel roof not as robust as concrete roof in resisting the effects of seismic loadings. The design of a steel roof may require substantial design analysis and subsequent strengthening to support the pipe work and platforms particularly under high seismic loads;
- Maximum design internal pressure not as high as full containment tanks with concrete roofs.

c. Full Containment

The full containment tank comprises of an outer pre-stressed concrete wall with reinforced concrete roof. For a tank of this construction the tank burn down scenario is not considered as a credible event (Ref EN 1473 Table 5). Potential fires will be limited to relief valve tail fires and ignition of small-scale spillages on the tank roof or in the main collection pit at grade level.

Release of vapour, even in the event of inner tank failure, will be controlled through the relief valves and flare system in order to prevent large-scale releases. As in the case of double containment tanks, all penetrations into the tank are through the roof. Penetrations in the tank shell or bottom are not permitted.

In addition to the safety criteria outlined above, the full containment tank offers the following advantages over double containment tanks:

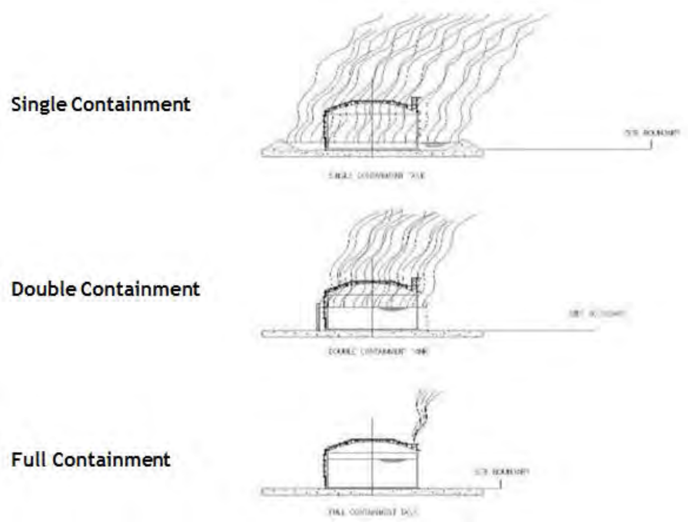
- Highest integrity giving increased protection of roof area from fire, blast, spillage, impact and seismic loads;
- Closer tank spacing reducing the land area required to site the tanks;
- Higher internal operating pressure due to concrete roof. This allows a greater flexibility in operation and lower levels of boil off gas to handle;
- The concrete roof provides a stable, robust platform for supporting pipe work and steel structures particularly in high seismic areas;
- Only a small increase in capital cost when compared to double containment tanks;
- Vapor dilution distances less.

d. Effect of Tank Containment Type Safety Distances

Fire Scenario

The following diagrams illustrate the effect of each tank configuration on the required safety distances to the site boundary considering fire and vapour dispersion emergency scenarios and underscore the clear benefits of selecting a full containment tank type:

Exhibit 3-11: Effect of Tank Type on Safety Distances



Vapour Dispersion

Exhibit 3-12: Effect on Tank Type on Dispersion Distances

3.4.1.3 Initial LNG Tank Screening Recommendation

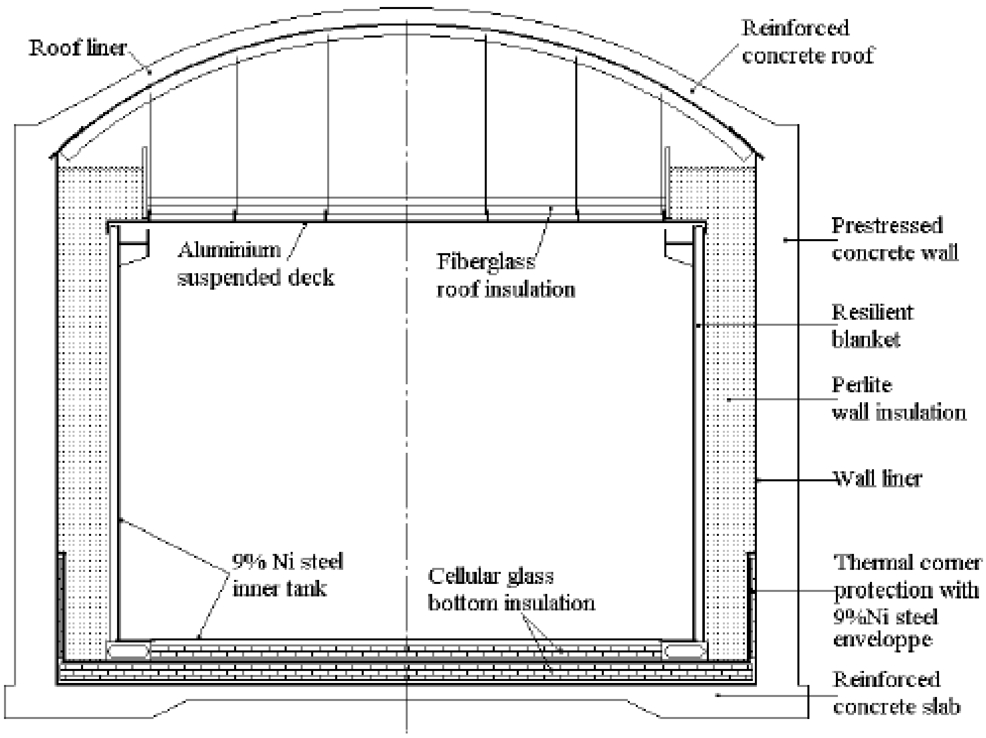
Considering the safety, risk, environmental and spacing criteria reviewed above it is recommended that only Full Containment type tanks or equivalent are selected for the proposed site location.

Full containment LNG storage tanks are selected as the preferred storage option based on the following criteria:

- Minimum spacing between adjacent tanks, other equipment and buildings, thus allowing best use of the limited available plot space;
- No need for space consuming secondary containment dikes or bund walls;
- Robust structure offering a high level of resistance to fire, blast, impact and seismic loadings;
- Concrete roof eliminates the need to consider tank burn down and subsequent adjacent tank fires (Ref EN 1473). Credible fire scenarios limited to relief valve tail pipe and LNG spillage collection pit. Hence, it is unlikely that a water deluge system will be required on the tanks;
- In an emergency situation, potential releases of LNG vapour will be controlled through the tank relief valve system avoiding uncontrolled large scale vapour dispersion into the surrounding area.

The most widely adopted full containment LNG tank configuration constructed at LNG facilities around the world over the last 20 years is the double wall tank with a 9 % nickel steel inner tank (primary containment) and a pre-stressed concrete outer tank (secondary containment). This "conventional" tank is commonly referred to as the PC / 9 % nickel tank. See Exhibit 3-13 for typical details:

Exhibit 3-13: Full Containment Tank Details



This has been the most commonly constructed tank type worldwide over the past 15 years with capacities of 160,000m^3 being typical, but with tanks up to 200,000m^3 now in service, and 260,000m^3 designs in place for future LNG terminals.

The tank design is proven and robust, with many tanks constructed in areas of high seismicity and poor soil conditions. The design permits relatively high design pressures (circa 290mbarg) compared to steel tanks allowing a degree of flash gas suppression in the tank potentially reducing the size of the Boil-Off Gas (BOG) compressors. The BOG limit is usually 0.05 % per day of the tank contents.

There are several contractors worldwide with the experience, capability and track record to design and construct this type of tank resulting in competitive tendering and pricing.

For the purpose of developing the LNG plant layout the PC / 9 % nickel full containment above ground tanks are used.

In general terms in-ground LNG storage tanks are significantly more expensive and have much greater construction periods that the equivalent above ground tanks (whether they are PC/9%Ni or membrane type) due to the extensive civil works associated with the constructing the pit.

Whilst it would be possible to construct an in-ground PC/9%Ni full containment tank, this is typically done only when there is a clear requirement from a height restriction (e.g. aircraft proximity) a planning/visual impact requirement, or to avoid a specific security risk.

A typical configuration for an in ground full containment (PC/9%Ni) tank would include a concrete lined pit, within which a "standard" full containment tank would be constructed. The impact on schedule would be of the order of 9-12 months, with a corresponding increase in cost of around 25 - 30% when compared to a conventional above ground equivalent. Therefore, in-ground LNG storage tanks are discounted for further consideration.

3.4.1.4 LNG Carrier Based Containment Technologies

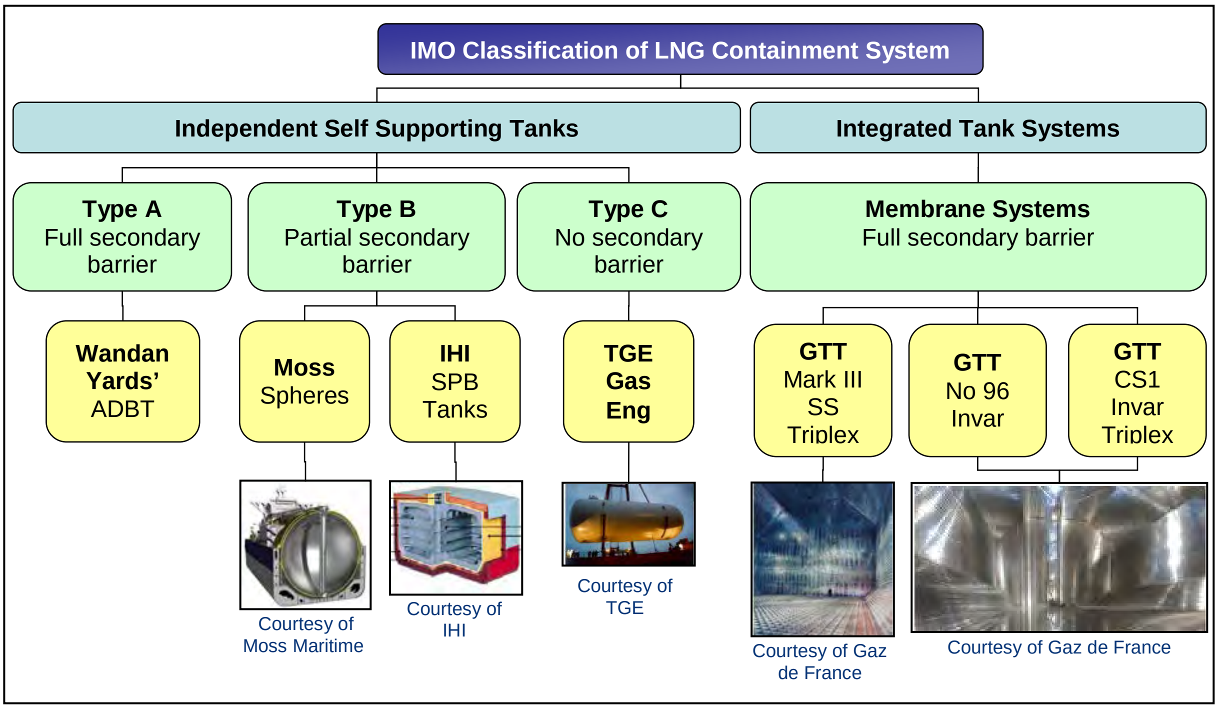
a. Overview

There are two general categories of LNG containment systems as used in LNGCs:

- Those based on independent self-supporting tanks;
- Those based on integrated systems (membrane type).

Both of these systems comply with the requirements of the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk published by the International Maritime Organisation (IMO-IGC Code). A diagrammatic summary of IMO's classification of LNG containment systems for use in floating vessels/ships is shown in Exhibit 3-14.

Exhibit 3-14: IMO Classification of LNG Containment Systems



Out of these, Moss and Membrane tanks are more commonly used for containment systems in LNGC and FSRU. These are briefly described below

IMO Type B: Moss Spheres

Moss Maritime of Norway developed the self-supporting spherical tank for the transportation of LNG in LNGCs. There is wide experience with this type of tank and 108 LNGCs have been constructed with Moss tanks, which comprise approximately 30% of the LNGCs in the world today.

Exhibit 3-15: Moss Spherical Tanks on an LNG Carrier

Moss tanks are manufactured from aluminium alloy (AA5083-0) with plate thickness ranging from 150 mm to 220 mm. The tank shell provides leak tightness and structural strength. The spherical tank deflects under hydrostatic and thermal loads but the deformation is not transferred to the vessel/ship structure as the sphere is supported on a long skirt attached around the circumference at the equatorial position. These skirts are fabricated from high tensile steel. The thick-plated aluminium sphere design is inherently structurally stronger than the steel alloy sheet used in membrane designs (refer Section 0).

Polyurethane foam insulation is applied over the aluminium shell and is protected by a steel tank cover. This achieves a BOG rate of approximately 0.15% per day (based on 220 mm of insulation). In LNGCs, the boil off gas (BOG) may be used for propulsion, whilst in FSRUs/FSUs application, the BOG may be used for power generation.

Moss tanks provide only primary containment. Partial secondary barrier is provided that relies on a "leak before failure" design premise, and is in the form of a drip tray located within the vessel/ship's hold and beneath the tank. The vessel/ship hold is designed to be gas tight, and the space around the tank is continuously purged and monitored for LNG vapour. On detection of a leak:

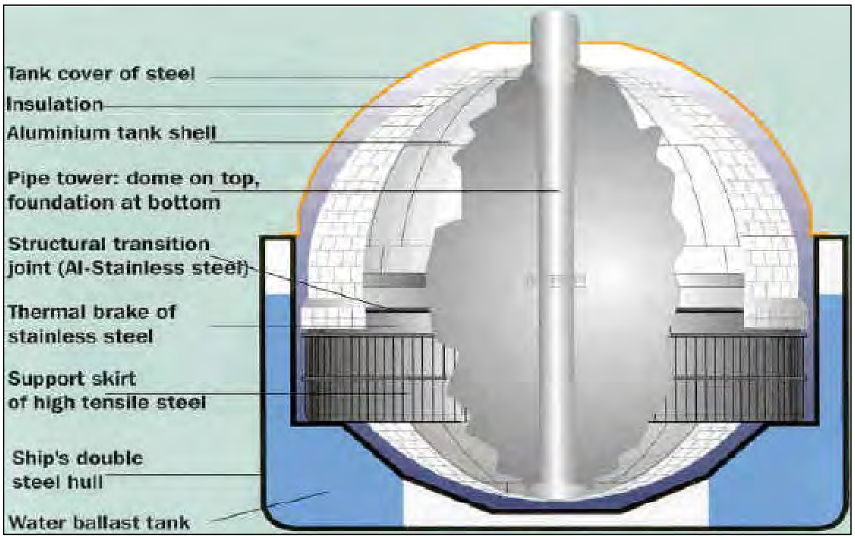
- For LNGC's: the carrier would sail to a terminal/port to offload the cargo from the leaking tank. The tank would then be de-commissioned and repaired. It may be possible for the carrier to continue to operate for some time with the leaking tank out of commission whilst awaiting repair;
- For permanently moored facility such as FSRU/FSU: the tank can be repaired on site due to easily accessible space between the tank and the vessel/ship's hull.

The tanks are generally pre-fabricated and lifted into the vessel/ship. Tanks are typically up to 40m in diameter and store up to 35,000 m^3. In 2010, Kawasaki shipping delivered the first two 180,000 m^3 Moss LNGCs, with each sphere having diameter of approximately 44 m. The size of the Moss spheres range from 39m to 44m and is dependent on shipyard tooling capabilities. Sizes of up to

56m diameter is possible, however, to date no shipyard has yet invested into the required infrastructure for fabrication.

Due to the inherent design of the spheres, sloshing forces on the tank walls are efficiently managed and is therefore not an issue.

Exhibit 3-16: Moss Spherical Tanks



FSRUs based on Moss spherical tank systems are currently in service (Golar Winter and Golar Freeze). The latest FSRU intended for Pertamina Jakarta Bay FSRU (Golar Khannur) and OPL's Livorno FSRU are both also based on Moss spherical tanks for LNG storage.

Integrated Tanks: Membrane System

Membrane tanks are non-self-supporting tanks and therefore do not fall under the IMO independent tank categories. Membrane tanks consist of a thin layer (membrane) supported through insulation by the adjacent hull structure (refer to Exhibit 3-17 for the membrane layer). The membrane is designed in such a way that thermal and other expansion or contraction is compensated for without undue stressing of the membrane. The thicknesses of membranes generally do not exceed 1-mm.

A liquid-proof secondary barrier provides full containment and conforms to the requirements of the IGC code if the secondary barrier is positioned such that the vessel/ship's hull/structure is protected from the cryogenic temperatures. Purge piping is provided behind the primary membrane barrier (between primary and secondary barrier) to detect leakage and to maintain a non-flammable atmosphere within the insulation section. On detection of leakage, the tank must be de-commissioned and repaired from the inside of the tank. As LNGCs usually include a single membrane tank, leakage will prevent the use of the LNGC until repairs at shipyards can be made.

Exhibit 3-17: Membrane Tank Liners

Membrane Liner

Thin stainless steel membrane with cold formed creases to accommodate thermal shrinkage.

The membrane systems are more space efficient than the Moss design due to the elimination of the access space around the tank. However, elimination of the access space means that tank inspections/repairs need to be carried out from inside the tank itself. In general this form of membrane containment system provides larger tanks at lower cost.

Exhibit 3-18: Membrane Tanks: Internal

The BOG rate is commonly set at average rate of 0.12% per day; although this rate can be influenced by the insulation chosen with averages ranging from 0.06% to 0.1% per day.

3.4.1.5 LNG Regasification Technologies

b. Background

One of the key technologies to be selected at a LNG regasification terminal is the vaporizer system and in order to guarantee send-out, most terminals have multiple parallel operating vaporisers with an appropriate level of additional spare units.

The purpose of this high level, qualitative assessment is to outline the regasification alternatives with some of the advantages and disadvantages.

LNG Regasification requires a heat input of approximately 200 Wh per kg of LNG, which is approximately 1.4% of the calorific value of the LNG being vaporized. The heat input can be achieved by; combustion, direct exchange with a "free" ambient source of heat such as seawater or air and by indirect exchange with an intermediate fluid with seawater, air or waste heat recovery.

Although, for the vaporizer technology selection for the OSRT; minimum use of the plot space is not considered as a key driver. Typically, low space utilisation requires low heat transfer area, which for constant duty, means either a high heat transfer coefficient or a high temperature difference (or both).

High temperature requires either fuel combustion or high grade waste heat recovery. For the proposed onshore OSRT, "hot" cooling water from the proposed adjacent power plant is identified as a significant low-grade waste heat source. Flexibility to utilise this available low grade heat for regasification may be considered in selecting the regasification technology as the CCPP and OSRT design develops.

c. Potential Vaporizers

The types of vaporisers typically in use can be classified based on the heat source for the LNG regasification and whether the heating is direct or indirect as below;

- Combustion
- Direct air/water or
- Indirect air/water types

Different vaporizers are tabulated below in Exhibit 3-19.

Exhibit 3-19: Summary of Vaporizers Type

Vaporiser Type	Exchange Mechanism	Heat Medium
Submerged Combustion Vaporiser (SCV)	Combustion	Combustion products and water bath
Open Rack Vaporiser (ORV)	Direct	Seawater
Ambient Air Vaporizers (AAV)	Direct	Air
Shell and Tube Vaporisers, including waste heat recovery vaporisers (STV)	Direct or Indirect	Seawater or Air and/or heat exchange fluid
Intermediate Fluid Vaporiser (IFV)	Indirect	Seawater and heat exchange fluid
Intermediate Fluid Ambient Air Vaporizers (IFAAV)	Indirect	Air and heat exchange fluid
Reverse Cooling Tower (RCT)	Indirect	Air and heat exchange fluid

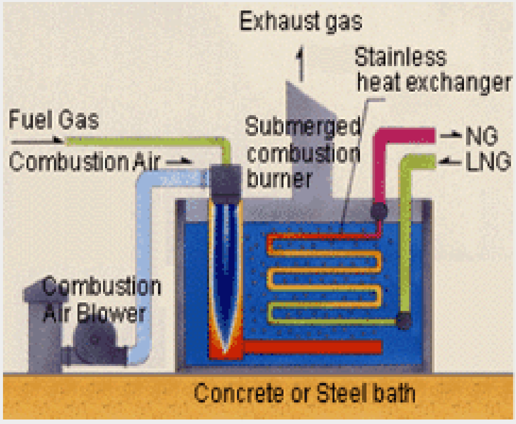
Alternative energy sources; geothermal, wind and solar are not in common use and have all discounted as being either unreliable or insufficiently intense (too expensive in space and capital) or both.

This review will address the various technologies as grouped by the heat exchange mechanisms.

Combustion

Submerged combustion vaporiser (scv)

Exhibit 3-20: Exhibit– SCV Schematic and Photo



Submerged combustion type exchangers, are currently in use at many regasification terminals as a back-up/emergency means of vaporisation or even as primary vaporizers. SCV's use fuel gas combustion (supplied as a side-stream from the regasified LNG) as the heat source, and although they represent a high OPEX solution, they are a relatively cheap CAPEX option and are very efficient in that most of the total calorific value of the gas is recovered (approximately 98% of HHV). The system uses submerged combustion to recover both the radiant heat and the heat associated with condensation of the combustion by-product water vapour. The submerged combustion maintains a bath temperature of 20°C to 60°C and has the benefit of convective mixing which results in excellent heat transfer to the LNG tube bundle.

The advantages of SCVs are that they are compact[13], have no marine impact and the water bath has a high thermal capacity, which in turn means that SCVs maintain stable operation even for sudden start-ups/shutdowns and rapid load fluctuations. They are also relatively low CAPEX.

The disadvantage of SCVs is that they are high OPEX as they burn high value gas as fuel; they have higher environmental emissions than the non-combustion technologies and have quite large power consuming combustion air blowers to overcome the liquid head of the water bath. There is also a need to neutralize the water acidity caused by dissolved CO_2 from the combustion gases.

Fuel gas and electricity costs associated with running a nominal 1.25MTPA (143 t/h) SCV are estimated at ~US$ 2040 per hour[14], approximately 8 - 9 times the cost of running a seawater pump for an equivalent ORV's duty.

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[13] Minimum required plot space for 1.25MTPA vaporizer is estimated at 525m^2

[14] Fuel gas consumption is estimated to be 2,484 kg/h together with a 450kW duty for the blower. Absorbed power for a single seawater pump is estimated at 1,134kW. Gas costs US$15 per mmbtu. Electricity cost of US$0.22 per kWh.

There is another mode of operation for an SCV, that is it can be used in non-fired mode (or part-fired mode) if supplied with warm water. Unfortunately, the SCV cannot use seawater directly as the warm water source as the mineral and salt contents result in rapid burner fouling, but the bath water can be circulated for seawater contact in an external heat exchanger that can be compact type, typically plate heat exchanger (PHE). It also cannot directly use the hot cooling medium return stream from nearby industry as the combustion products foul the water and can cause equipment damage. In this scenario, water bath circulation and cross exchange by PHE is required.

The addition of the PHEs will increase plot space and will increase CAPEX compared to a stand-alone SCV without 'supplementary heating'. However, when hot water is available it lowers OPEX as it is cheaper to pump the hot water than it is to burn fuel gas. The dual service SCV also provides some diversity as it still facilitates the use of fuel gas firing during prolonged loss of sea water supply.

On the basis that, SCV is the highest OPEX vaporizer amongst the vaporizer types under consideration, SCV is not recommended as preferred vaporizer for primary vaporization.

Direct Heat Transfer – Not integrated systems

Direct heat transfer technologies utilize the available "free" energy sources of air and water directly. The high heat capacity of water relative to air means that use of water as heat source by ORV's and STV's ORV's have a much lower footprint requirement than air technologies IFAAVs, RCT's, DAAV's and FAV's and could be considered as a preferred solution on the basis of low plot space and low OPEX if the terminal was to be implemented as a standalone send-out facility.

<u>Open Rack Vaporiser</u>

Direct seawater exchangers are in use at several operating regasification terminals. ORV's are a robust, simple technology that uses an open rack falling film of seawater over open rack aluminium panels which the LNG flows through. The key advantages of ORVs are; low-space requirement, reliability and low OPEX.

Exhibit 3-21: ORV Schematic

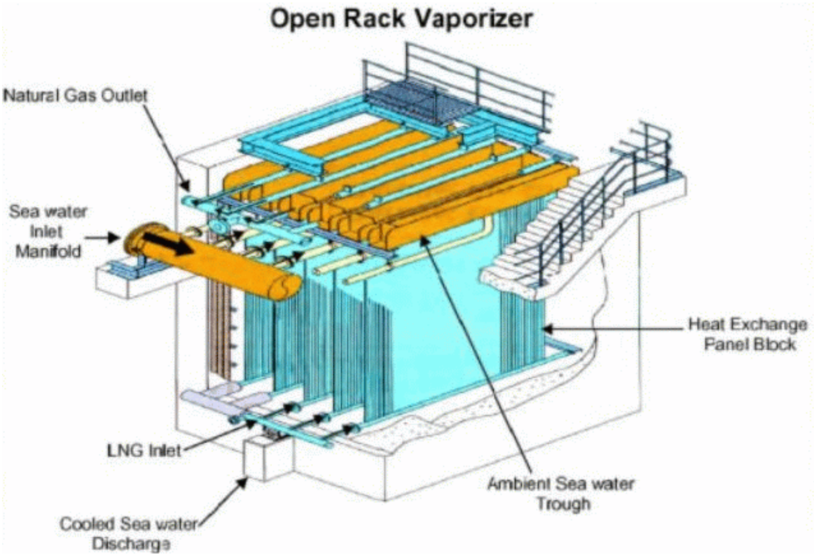


Exhibit 3-22: ORV Photo

The above schematic (Exhibit 3-21 and Exhibit 3-22) indicate the size and consideration of an ORV in which seawater flows downwards over LNG containing heat exchange panels and is gathered in a concrete basin prior to discharge back to the ocean.

In addition to the ORV unit itself, the use of open rack vaporiser technology requires a significant investment in the site seawater systems for pumping, treatment and disposal.

Advantages:

- Proven technology,

- Reliable
- Low Opex
- Low space requirement
- No freezing risk

Disadvantages:

- Restrictions on sea water quality,
- Few manufacturers and resultant high cost,
- Periodic shut down for recoating,
- Potential seawater recirculation
- Open outlet requiring gravity flow for sea water disposal
- No opportunity for energy integration

Direct Ambient Air Vaporisers (DAAVs)

Direct Ambient Air Vaporisers use heat extracted from ambient air including latent heats of condensation and fusion of atmospheric moisture to vaporize LNG without using an intermediate heat transfer fluid. Ambient Air Vaporisers are essentially vertical heat exchanger tubes arranged so that a downward air draft is facilitated. They may be natural draft (DAAV) or forced draft (FAV).

DAAV's use no power or fuel to heat the LNG as the thermal gradient draws an air into the top of the bundle and exhausts cold air at the bottom; however fog mitigation requires the use of fans and has a resultant power demand. Air is drawn into the DAAV when the ambient air is chilled by the warming LNG and drops through the center of the vaporizer. Simultaneously, the LNG flows upwards in the tubes, is vaporized and warmed to a temperature approaching ambient air temperature. The air, after cooling and depositing bulk of the moisture in it onto the heat transfer surfaces, exits out the bottom where it mixes with the surrounding air.

Exhibit 3-23: 200 MMcf/d (~160t/h) DAAV's at Sabine Pass LNG Terminal

Forced Air Vaporizers (FAV's) have the ability to move more air across the heat exchange surface and are therefore more intense than DAAV's and require less space than DAAV's.

Preliminary information from one vendor contacted for similar study shows both DAAVs and FAV's could be a potential alternate vaporizer. For 2.5MTPA LNG regasification terminal, total of ~15 trains with 4 cells per train would be required and would occupy a site area of approximately 9m x 144m, which is reasonable for a terminal send-out capacity as low as 2.5MTPA.

Based on site meteorological data a DAAV system could be designed to supply high pressure gas at the minimum pipeline temperature of 5°C (typical send-out gas temperature) with no trim heating required.

For fog mitigation, typically ambient air vaporizers (DAAV's) are coupled with fans and are termed as forced air vaporizers (FAV's), 40kW power per fan will be required and one fan per cell would mean total power demand of 2400kW for 2.5MTPA regasification.

DAAV and FAV direct contact vaporizers are extremely flexible from a process and operational standpoint and below are the key characteristic of these vaporizers:

- 100% operating envelope - can run from 1% through 100% sendout capacity;
- Instantaneous start-up time: - DAAV's begin vaporizing upon supply of liquid. No delay period or ramping up required;
- Instant shut down;
- No emissions;
- No power (AAV only);
- No fuel;
- Little maintenance;
- No noise discernible above background noise;
- No chemical additions or neutralizing;
- No makeup fluids;
- No pumps, and;

The main disadvantage of DAAV's/FAV's is that they are relatively high CAPEX when compared to SCV and ORV. Budgetary equipment prices obtained from one vendor during a similar study ranged from US$9,800,000 for an FAV option to US$11,725,000 for a DAAV scheme (plus US$1,175,000 for fog mitigation). For comparison, budgetary costs for a 143t/h SCV have been advised by one of the SCV vendor as US$4,900,000.

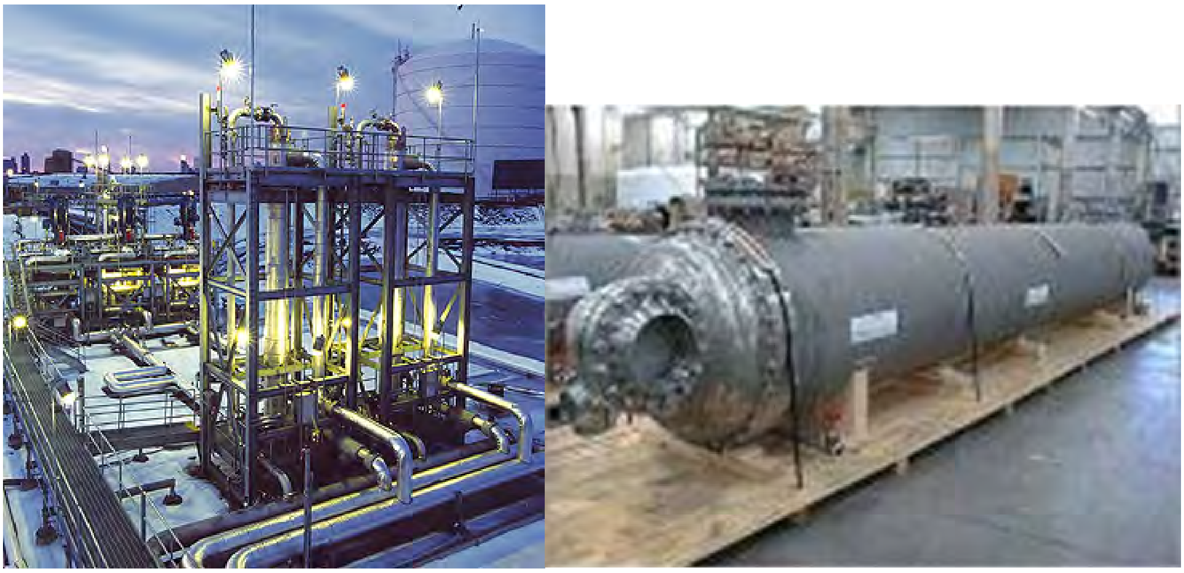
Exhibit 3-24: DAAV Photos

Typical Photo - Natural Draft Type | Typical Photo - Forced Draft Type

Indirect Heat Transfer

Shell and Tube Vaporisers (STVs)

Exhibit 3-25: STV Photos



Shell and tube vaporisers can be direct or indirect type whereby seawater is used as the heating medium directly or a low temperature heat transfer fluid (HTF), which is heated by ambient air or some other process heat source such as seawater provides indirect exchange.

Shell and tube vaporisers are conventional shell and tube exchangers with some details to suit the service (e.g. tube inserts). They have the prime advantages that they are economic and compact (as they are typically vertically-mounted with the heating liquid on shell side and LNG on tube side). However, they are not a standalone solution. Shell and tube heat exchangers require a source of heat, which may be extracted from ambient source or from waste heat from another fuel combustion process.

For a STV using direct heat exchange from seawater or fresh water, the following advantages and disadvantages apply;

Advantages:

- Low Cost
- Compact
- Minimal cryogenic piping requirements

Disadvantages:

- Freezing risk
- Seawater cost (pumps, treatment etc)
- Corrosion risk (for seawater)
- Restrictions on sea water quality (for seawater)

The freezing risk is considerable and means that most STV exchangers are typically used with a secondary loop heat exchange medium such as glycol/water solution which has a lower freezing point. The advantages and disadvantages relative to direct exchange are;

Advantages:

- Reduced risk of freezing (compared to direct STV)
- No corrosion risk

Disadvantages:

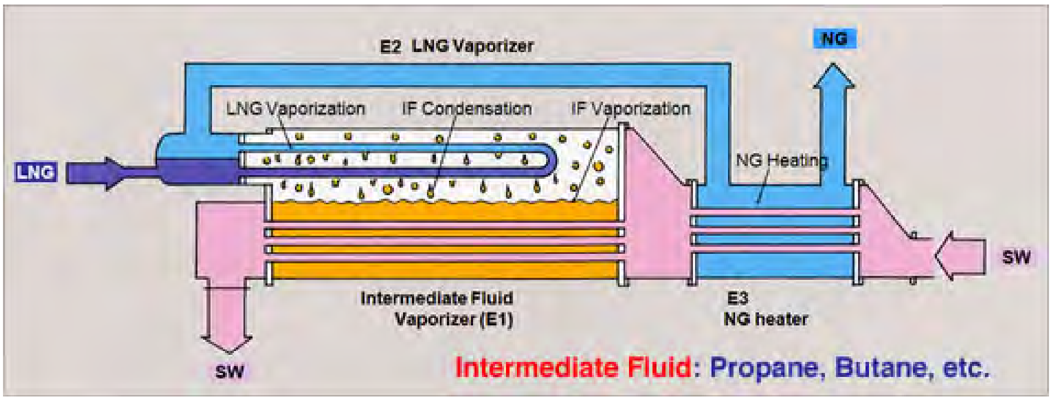
- Extra equipment
- Higher OPEX

The increased complexity of the STV with secondary loop and seawater over standard ORVs means that STVs are not preferred unless there is an external heat supply. STVs heated directly with seawater are not generally recommended for land-based service due to risk of freezing, corrosion and erosion. This moves assessment of STV's towards some of the other technologies such as RCT, IFAAV or WHRV, as discussed in the subsequent sections.

<u>Intermediate Fluid Vaporiser (IFV)</u>

A variant of a shell and tube vaporizer is an intermediate fluid vaporizer. IFVs use seawater as the main source of heat. They have mainly found use (on land-based Terminals) where poor seawater quality makes ORVs[15] unsuitable. Two significantly different designs are available. Both use seawater and achieve compactness by utilising condensing film heat transfer coefficient (of propane).

Exhibit 3-26: IFV Schematic



[15] The large pressure vessels associated with conventional IFVs makes them higher CAPEX than ORVs of the same capacity. OPEXs are similar.

Exhibit 3-27: IFV Photos

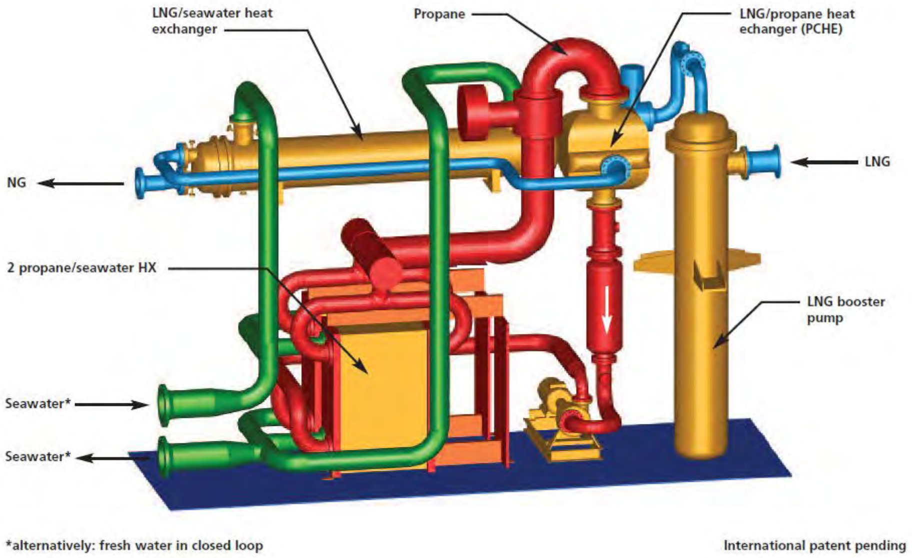
A conventional IFV essentially comprises of a pressure vessel containing two heating coils (an upper coil and a lower coil). The vessel (typically) contains pressurised propane liquid, which covers the lower coil. Seawater is run through the lower coil and the heat transfer vaporises the propane. LNG is fed to the upper coil and is vaporised with heat supplied by propane vapour condensing on the outside of the coil. Condensed propane drops back into the pool covering the lower coil, where it is continuously re-vaporised.

The above type of IFV is more expensive than ORV’s and could be discounted as it offers no benefit over an ORV; however, it offers a significant advantage in facilitating potential for cold energy export as the seawater can be switched over to a heating/cooling medium.

A compact IFV has recently been adopted onto floating regas vessels. There is no reason the same technology could not also be used on land. The unit also uses seawater as the heating medium and also uses propane as an intermediate HTF. The unit utilises three different heat exchangers (Exhibit 3-28 and Exhibit 3-29 are so-called compact heat exchangers, which save space by providing a very high heat transfer surface to volume ratio):

- A PHE to vaporize pressurized propane liquid using seawater as the heating medium;
- A PCHE to vaporize LNG using condensing propane vapor as the heating medium;
- A shell and tube heat exchanger to provide trim heat to the vaporized LNG to required ‘send-out temperature’.

Exhibit 3-28: Compact IFV Schematic



The disadvantage of the above unit is that it requires a pump to circulate propane. It is therefore less reliable than a conventional IFV or an ORV. Therefore, IFV is not considered as a preferred vaporizer technology.

<u>Intermediate Fluid Ambient Air Vaporiser (IFAAV)</u>

IFAAV's typically operate in addition to STV's. IFAAVs use ambient air as the primary heat source, but use an intermediate heat transfer fluid, which facilitates heating by a secondary heat source when ambient temperature is low or a close temperature approach is required.

Exhibit 3-29: IFAAV schematic

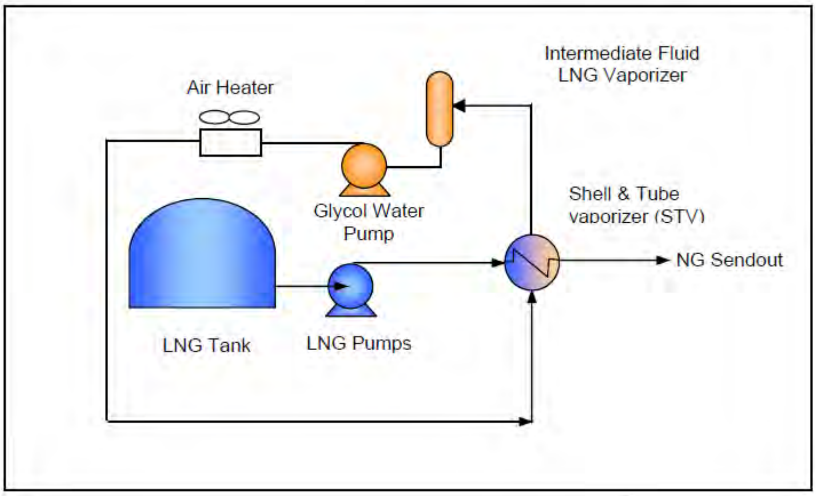


Exhibit 3-30: IFAAV Photo

The IFAAV uses air heated exchangers (AHE's/ACHE's/fin-fans) as heaters for a heat transfer fluid. Warmed heat transfer fluid (typically 30% ethylene glycol solution) is circulated through the ACHEs and the Vaporiser(s) (typically shell and tube heat exchangers – see previous). As the air cools on passage through the ACHEs, water vapour is condensed and fresh water may be harvested.

Air Heated IFV commonly use forced draft fin fan air exchangers to extract heat from the air; the latent heat released from the condensation of moisture in the air then heats an intermediate heat transfer fluid (HTF). The HTF is subsequently used to vaporise LNG in a shell and tube exchanger.

Considering a system size equivalent to a 143t/h (~1.25MTPA) SCV for comparison purposes, an IFAAV system would comprise of a total of 8 bays of fin fan exchangers, having overall dimensions of approximately 60m x 20m. Each bay would include two fans with motor ratings of 30kW and an absorbed power of 25kW per fan. Including the HTF pump gives a low total power requirement of 640kW.

For the 2.5MTPA terminal, the plot space requirement for fin fan exchangers is ~ 2400 m² and IFAAV will provide the flexibility to integrate the regasification process with the power plant heat source (the air heaters can be idle or made redundant when the heat is provided by the power plant). Typically, IFAAV CAPEX is comparable with FAV's for similar capacities.

Reverse Cooling Tower (RCT)

Reverse Cooling Towers (RCT's) as the heat source for LNG vaporisation are an alternative to forced draft fin fan air exchangers. These are in use at the Freeport LNG Terminal in Texas. A RCT is simply another way of extracting heat from ambient air. Cold water is fed to the top of a cooling tower and the forced down draught of air warms the cold water. The warmed water is collected in the tower pond. A heating coil in the pond transfers heat to a HTF, which in turn circulates through the LNG vaporiser (typically a STV).

The RCT's (although less than IFAAVs) would occupy significant space at approximately 2,000 m² for 2.5MTPA regasification capacity. In which case, the space required is comparable with IFAAV space requirement

Their CAPEX is similar to IFAAVs, but their OPEX is greater. (The additional heat exchange loop means that the close temperature approach is more difficult to achieve requiring more supplementary heating.) Nevertheless, it is considerably lower OPEX than an SCV. There is only one known installation, so the technology is considered to be novel. The supplier of the RCT's to Freeport LNG Terminal was contacted for previous vaporizer studies and declined to provide any detailed information. Therefore, RCT is discounted for further consideration due to lack of vendor interest, installation references and higher OPEX compared to IFAAV.

Exhibit 3-31: RCT Photo

3.4.2 Near Shore

Two options are presented for Near Shore: Floating Storage and Regasification Units (FSRU) and Floating Storage Unit (FSU). The various mooring options are discussed in Section 5

3.4.2.1 FSRU

This solution consists of a vessel, new or reconverted from a carrier, equipped with tanks for LNG storage and with all the required vaporization process equipment. Thus, FSRU can be termed as a special type of ship which is used for LNG transfer and Regasification of LNG.

FSRUs can be equipped in two ways:

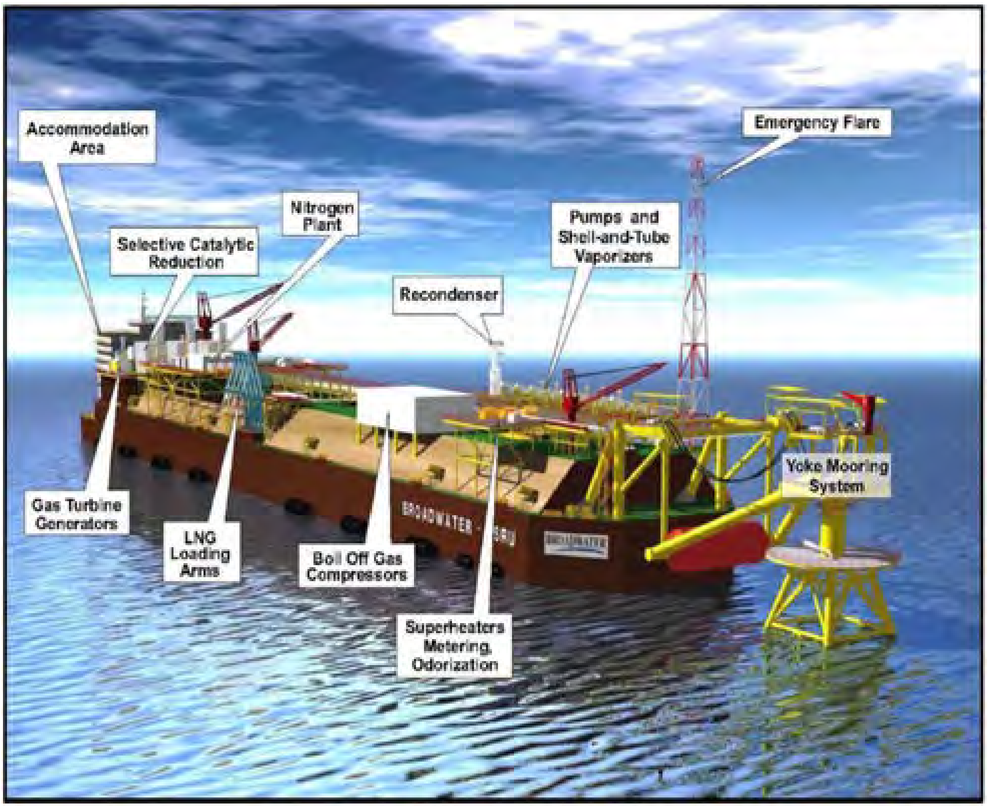
- either they can be equipped as a separate unit aboard the LNG carrier itself or,
- an old gas carrier can be converted into an independent unit and placed in a particular destination

A typical FSRU consists of:

- LNG containment system used to store LNG in its liquid state at minus 160-165 ˚C.
- LNG in-tank pumps to transfer LNG from containment tanks
- LNG booster pumps to increase pressure to meet the required regas supply pressure.
- LNG Regasification equipment
- and connection for High pressure marine loading arm for supply of regasified NG.

Typical FSRU components are shown in Exhibit 3-32.

Exhibit 3-32 Typical FSRU Components



Containment in FSRUs are mostly Moss type Tanks or Membrane tanks (refer description of these type of Tanks in Section 3.4.1.4). A number of floating LNG technologies is available. For the purpose of the pre-feasibility design of the marine terminal a dual berth jetty concept is considered, as shown in Exhibit 3-33.

Exhibit 3-33: FSRU with Jetty Structure

Description:	• This configuration is based on an FSRU moored to a dual berth jetty structure.
	• The jetty structure can be constructed using either:
	  o Steel piles installed on site
	  o Pre-fabricated jacket structures constructed onshore. The jacket structures are then floated out and installed on site
	• The jetty includes mooring/fendering structures to moor the FSRU and LNGC, and loading arms for LNG transfers. High pressure piping is used to transfer natural gas from the FSRU unit to a subsea PLEM, and via subsea pipeline to shore.
	• In **Exhibit 3-33** the LNGC is moored on the left of jetty and the FSRU on the right.
	• The FSRU is expected to sail away when rough sea conditions (severe storms and/or cyclones) are forecasted.

Storage capacity:	FSRU: 125,000 m^3 to 173,000 m^3 converted from standard LNGC containment systems
Water depth:	Typically 14 to 16 m
LNG transfer:	Via marine loading arms
Mode of operation:	LNG is transferred from the LNGC to the FSRU via loading arms and piping on the jetty.
Examples:	• Guanabara Bay, Brazil, Golar Winter FSRU: in operation • Pecem, Brazil, Golar Spirit FSRU: in operation • Jebel Ali Port, Dubai, Golar Freeze FSRU: in operation • Jakarta Bay, Indonesia, Golar Khannur FSRU: undergoing construction

3.4.2.2 FSU

Floating Storage Unit (FSU) only stores the LNG. LNG from the FSU is then transferred to the Jetty via Marine Loading Arms. The equipment for boil-off gas management, LNG booster pump and LNG regasification are installed on the Jetty. The 5 MTPA Melaka LNG Terminal (Exhibit 3-34) is an example where a 130,000 m^3 FSU vessels are used as storage of LNG in a FSU and Regasification is done on the Jetty.

There is practically no conversion required for an LNGC to be used as a FSU. However, the Jetty (or the Platform) on which the BOG and Regas equipment are installed is much larger than in case of FSRU. FSU can be adopted where there are seasonal demands: high demand in summer and limited or no demand in winter such as in the Middle East countries. In such countries FSU can sail away and be used as LNGC.

Exhibit 3-34: Melaka LNG Terminal

3.4.3 Off-Shore

Below is a summary of possible Gravity Based Structure (GBS) technologies available: GBS – Concrete, GBS (Steel) and “GraviFloat”.

3.4.3.1 Gravity Based Structure (GBS) – Concrete

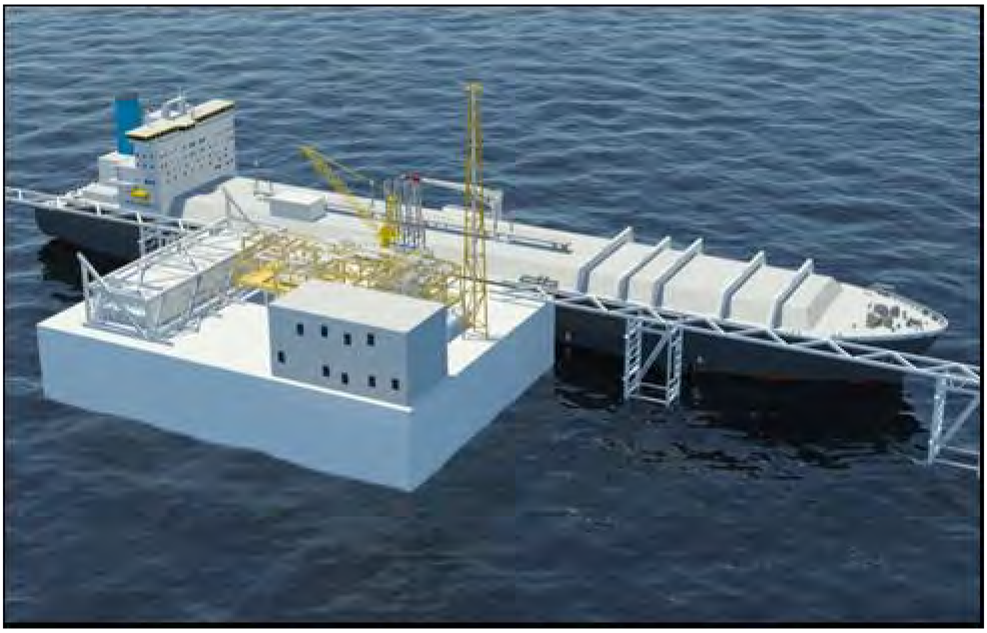
Exhibit 3-35: Gravity Based Structure – Concrete

Description:	• This concept uses a concrete gravity based structure (GBS), which includes LNG storage tanks, the regasification unit, mooring/fendering systems (for mooring the LNGC alongside the GBS) and loading arms for LNG transfers. • The entire GBS structure is constructed in a specialized dock. Upon completion, the dock is flooded to allow the GBS structure to be towed out to site. Once on site, ballasting is used to “sink” the GBS onto the seabed. • High pressure piping connecting the outlet of the regasification unit to the subsea pipeline is used to transfer gas to shore.

Storage capacity:	125,000m^3 to 250,000m^3 using membrane containment system.
Water depth:	Typically 16 to 30m.
LNG transfer:	Via loading arms.
Mode of operation:	LNG is transferred from the LNGC to the storage tanks in the GBS structure via loading arms.
Examples:	• Adriatic LNG Terminal: in operation

3.4.3.2 Gravity Based Structure (GBS) – Steel

Exhibit 3-36: Gravity Based Structure – Steel



Description:	• This concept is similar to the concept described above except that the GBS is constructed entirely out of steel instead of concrete. • The GBS structure includes LNG storage tanks, the regasification unit, mooring/fendering systems (for mooring the LNGC alongside the GBS) and loading arms for LNG transfers. • As the GBS structure is to be made of steel, the entire unit can be fabricated in a large number of shipyards. Upon completion, the GBS structure will be towed out to site and ballasted to "sink" the GBS onto the seabed. • The water depth limitations of such structure is governed by cost, where any increase in water depth significantly increases the cost as deeper steel GBS structure is required. • High pressure piping connecting the outlet of the regasification unit to the subsea pipeline is used to transfer gas to shore.
Storage capacity:	• 40,000m3 to 80,000m3 using IMO Type B or Type C systems.

	• 125,000m3 to 250,000m3 using membrane/independent prismatic containment system.
Water depth:	Typically 16 to 22 m.
LNG transfer:	Via loading arms.
Mode of operation:	LNG is transferred from the LNGC to the storage tanks in the GBS structure via loading arms.
Examples:	• None

3.4.3.3 GraviFloat

Exhibit 3-37: GraviFloat Storage Technology

Description:	• The GraviFloat design is a modular proprietary design by GraviFloat/ BW-Venture. The system utilises, suction anchor type gravity foundation. • Fabrication in shipyards and towed to site. • Modules interconnected via trestles and NG piping via trestle to shore • The GBS structure includes LNG storage tanks, the regasification unit, mooring/fendering systems (for mooring the LNGC alongside the GBS) and loading arms for LNG transfers. Storage in membrane or Moss type tanks. • As the GBS structure is to be made of reinforced concrete, the entire unit can be fabricated in local shipyards (depending on tank license agreement and skilled tank installation labor). Upon completion, the GBS structure will be towed out to site and ballasted to “sink” the GBS onto the seabed. • The water depth limitations of such structure is governed by cost, where any increase in water depth significantly increases the cost as deeper and heavier GBS structure is required.

	• High pressure piping connecting the outlet of the regasification unit to the pipeline on a trestle for to transfer gas to shore.
Storage capacity:	18,000m^3 - 200,000m^3 .
Water depth:	14-18m.
LNG transfer:	Via loading arms.
Examples:	None

3.4.4 Small Scale LNG Terminal concepts

Small scale LNG is still in its infancy but the pressures to extend the LNG supply chain into coastal distribution and other downstream activities are now building by the day. More and more potential customers are attuned to the environmental and possible cost-saving advantages that natural gas has over alternative fossil fuels.

Where previously there was hesitancy to commit due to the absence of adequate LNG supply infrastructure, the growing strength of the arguments in favour of gas and the spread of the global large-scale LNG network are poised to force a breakthrough. The additional support offered by various governments is adding to the momentum.

To date, small-scale LNG distribution using seagoing vessels has been limited to Norway and Japan. Japan utilises five small dedicated tankers in the 2,500-3,500m3 size ranges to take LNG loaded at the country's main import terminals to small local communities otherwise difficult to access.

Norway employs a 1,100m^3 LNG carrier and a fleet of road tankers to distribute gas to remote locations along the country's long coastline. A principal driver of small-scale LNG is the use of LNG as a marine fuel and this has been a major factor in the strengthening Norwegian commitment. There are now approximately 25 ferries, offshore supply vessels and coastguard craft in Norwegian coastal service that run on LNG and the fleet is growing. These vessels derive advantage from the levy imposed by Norway's government on ship emissions of nitrogen oxides (Nox).

In addition to the Norwegian and Japanese coastal tankers there are seven multipurpose LNGC's in the 7,500-12,000m^3 size range now in service. These ships have been built with the global potential for small-scale LNG in mind and their ability to also carry other liquefied gases, such as ethylene, will ensure that they kept employed until their LNG services are required.

One potential new market for some of these multipurpose LNG ships is Indonesia. The country's government has recently sanctioned the establishment of ten (10) coastal LNG receiving terminals in the eastern part of the vast island nation. These facilities will be serviced by a fleet of small LNG carriers which load at one of the country's LNG export terminals and distribute cargoes locally on a series of "milk runs".

In Northern Europe the small-scale LNG concept is spreading out from Norway. A 7,500m^3 multipurpose LNG carrier is being employed to ferry cargoes from a medium-size liquefaction plant in

Norway to a new LNG receiving terminal in Sweden while a dedicated 15,600m^3 LNG carrier is under construction in Germany and earmarked for distribution duties in Northern Europe and Scandinavia.

3.4.4.1 Small Scale LNG as an Option for Mauritius

Economically small-scale LNG makes sense over small distances between LNG supply source to LNG consuming location i.e. between 100 nautical miles and 500 nautical miles (approx. 350 to 950km). This is for the reason that then the LNG supply turnaround time will be less and accordingly less LNG needs to be stored.

For 0.3 MTPA LNG demand as projected for Mauritius in base case is equivalent to 75 m^3/h, a 30,000 m^3 storage will store about 16 days of LNG.

The limitation in this case would be the distance and the sailing time of 30,000 m3 LNGC's adding to the LNG supply cost (with LNGC sailing at 18 knots and considering distance of 3500 miles, sailing time is 160-170 hrs, that is 6-7 days one way & a turnaround period of 18 to 20 days including time for loading and unloading).

There are following three concerns envisaged in technically and commercially recommending a small scale LNG option for Mauritius besides the commercial challenges. These are:

- There are currently no LNG supply sources able/willing to accommodate and load smaller LNGC's
- Potential small scale LNG supply sources being too distant to Mauritius
- Lack of application of small LNG carriers for shipment to long distances

There are no small scale FSRU systems in operation. Small scale LNG for FSRU can only be commercially successful for short distance supply chains (~200-300NM). The system relies on a spoke and hub model. The number of ships required in the logistical chain to supply a constant flow of natural gas drive the cost (all of which have to be new built) and depending on capacity, a cost cross-over is somewhere around the 250 NM shipping distance mark when compared to midscale to large scale FSRU developments.

In addition, the current fleet is too specialised to be considered in the context of a 0.5 MTPA to 2.5 MTPA regasification terminal located remotely (>1500NM) from LNG liquefaction or other interim storage terminals.

Small scale LNG logically may expand in the future. Possible other options would be a "Hub and Spoke Concept" or "Disconnectable Twin supply chain of small 60,000 m^3 LNGC's", but each one of these has their own limitations. Specifically for Mauritius, the limitation to use Hub and Spoke principle is that there is no LNG Terminal in the vicinity of Mauritius. For the Disconnectable Twin supply chain of small 60,000 m^3 LNGC's, small 60,000 m^3 LNGC's are chartered to supply LNG from a trading terminal such as from Singapore. The limitation in this case would be the distance and the sailing time of 60,000 m^3 LNGC's adding to the LNG supply cost (with LNGC sailing at 18 knots and considering distance of 3500 miles, sailing time is 160-170 hrs, that is 6-7 days one way & a turnaround period of 18 to 20 days including time for loading and unloading). A detailed discussion on this is beyond the scope of this report, for the reasons mentioned above, small scale LNG is not further considered.

3.4.5 High Level Comparison of technologies & Selection

The below exhibit, Exhibit 3-38, present a high level comparison of the various LNG import terminal technologies described in the sections above and is then followed by a technology selection rationale for this study.

Exhibit 3-38: Summary of LNG import Terminal types

Description	On-shore	Near Shore	Off-shore	Remarks
Capacity	Generally 3 MTPA or more	Generally 1-3 MTPA	Generally 1-3 MTPA	
On ground Area Requirement	10-20 ha depending upon capacity	1-2 ha	1-2 ha	
Off-shore requirement	Jetty for LNGC Berthing 120,000 to 265,000 m^3	Single or Dual Jetty	Suitable Mooring arrangement for Metocean and draft	
Off-loading	By Marine Loading Arms installed on Jetty	Single Jetty: FSRU moored to Jetty, Ship to ship transfer Dual Jetty: Both FSRU and LNGC moored to Jetty	Ship to Ship transfer	
Draft requirements	Generally ~12-16 m	Generally ~12-20 m	Generally~40-50 m	
Storage/ Containment System	Full Containment tanks	Moss or Membrane Tanks	Moss Tanks/ Membrane Tanks Note 1	membrane tanks would require careful consideration for sloshing
Off Loading	Marine Loading Arms	Marine Loading Arms/ hoses	Marine Loading Arms or hoses	
Feasibility to First Gas Schedule	Onshore Terminal ~ 48 months	Near shore Terminal 30-36 months	Off-shore 34-38 months	

Note 1: Membrane tanks would require careful consideration for sloshing

Considering the limitation of Onshore Plot space at Port Louis and requirement of expensive reclamation, an onshore LNG Terminal is not considered.

There is adequate draft available near shore (see Section 4) to berth a 173,000 m^3 FSRU. A single berth for off- loading LNG from LNGC with Ship to Ship Transfer or a dual berth jetty to berth FSRU on one side and LNGC on the other side are both possible. The concept adopted will follow the near shore LNG import Terminal. Some of the LNGC suppliers are reluctant to agree for Ship to Ship transfer. To allow greater flexibility in LNG supply from LNGC a dual Jetty concept has been proposed (for a comparison of mooring options and selection of a preferred option, also refer to Section 5.4.3). The Jetty will have Marine Loading Arms for transfer of LNG from LNGC to jetty and another set of MLAs for transfer from Jetty to FSRU. HP Arm will transfer Regas NG from FSRU to Jetty. The Regas NG will be transferred to On-Shore Receiving Facility (ORF) by sub-sea pipeline. The ORF will broadly have Filter, Pressure Let Down and the metering station.

In case of a FSU, the Regas equipment and BOG management will need to be either on the Jetty or on-shore. If Regas is done on the Jetty, all the utilities required viz. electric power, sea water will be required to be done on jetty and this will require 24x7 operations & maintenance manpower on jetty. Also the Jetty or the Regas platform will be much bigger. If Regas is done on-shore, expensive cryogenic lines will need to be run to Onshore Regas Terminal. Considering these aspects, FSU option has not been considered.

3.5 Cost Estimates & Construction Schedule

Due to the integrated nature of the cost and schedule for the LNG infrastructure and the Port and Marine infrastructure, these aspects are discussed together in Section 5.5 and not presented separately for the LNG Import Terminal here.

3.6 Conclusions and Recommendations

Due to the integrated nature of the LNG infrastructure and the Port and Marine infrastructure, the conclusions and recommendations are included together in Section 5.6 and not presented separately for the LNG Import Terminal here.

4. SITE EVALUATION

4.1 Introduction

This section presents the site evaluation for the three sites proposed by the CEB for this study: *JinFei - Baie de Tombeau*, *Old Port Site - Bois des Amourettes* and *Les Grandes Salines*. Two of the sites were eliminated during the Kick-Off Meeting visit by the WorleyParsons team to Mauritius based on inspection. The alternate sites were discussed with CEB during the Wrap up meeting on 06 Dec 2013 [12] and it was agreed to only consider the Les Grandes Salines site for the new power plant. No further detailed study was performed on *Baie de Tombeau* and *Bois des Amourettes* and therefore the section deals exclusively with the suitability of the *Les Grandes Salines* site.

4.2 Overview of Other Sites Considered

Based on the physical site visits and discussions with the Ministry of Environment and Sustainable Development and Ministry of Housing and Land, these alternate sites were deemed unsuitable (from first inspection) for a new power plant for the following reasons:

- JinFei - Baie de Tombeau:
  - The site is surrounded by residential areas
  - The site is located a relative distance from the shore line that would create some difficulties in LNG to Power Plant integration
  - Right of way would be an issue
  - The site is a special purpose zone. The property is leased to the Chinese government. The Chinese government can sub-lease it to others for similar usage as in the original lease but it can probably not be converted into an Industrial zone for Power Plant.
  - Since the site is surrounded by a residential zone it also requires special attention on what can be put at the site

- Old Port Site - Bois des Amourettes:
  - The existing jetty is small and the water depth shallow. It would require substantial rework for any new LNG import facility.
  - Based on discussions with the Ministry of Environment and Sustainable Development, the marine location has corals and Ministry of Fishery has special regulations on not damaging/ disturbing the corals.
  - The site near the old abandoned tank farm area is rather sloped and will require significant earthwork and demolition for any new power plant.
  - There are residential areas close by. The area is scenic with good vegetation and flowers. A new power plant in the area will require removing / relocation of the flora and would disturb the current environment.
  - There are hardly any industries or any major load centre and there does not seem to be suitable HV transmission lines close by.

4.3 Due Diligence – Les Grandes Saline Site

4.3.1 Power Plant Considerations

This section presents information on Les Grandes Saline site from the perspective of the new power plant and includes the following information.

1. High level footprint requirement for Power Plant
2. Proximity to Transmission line.
3. Proximity to Residential area.
4. Site Accessibility and transport infrastructure.
5. Land Ownership issues – Land is allocated to CEB, and CEB can acquire additional land.
6. Proximity to the LNG tanker jetty.

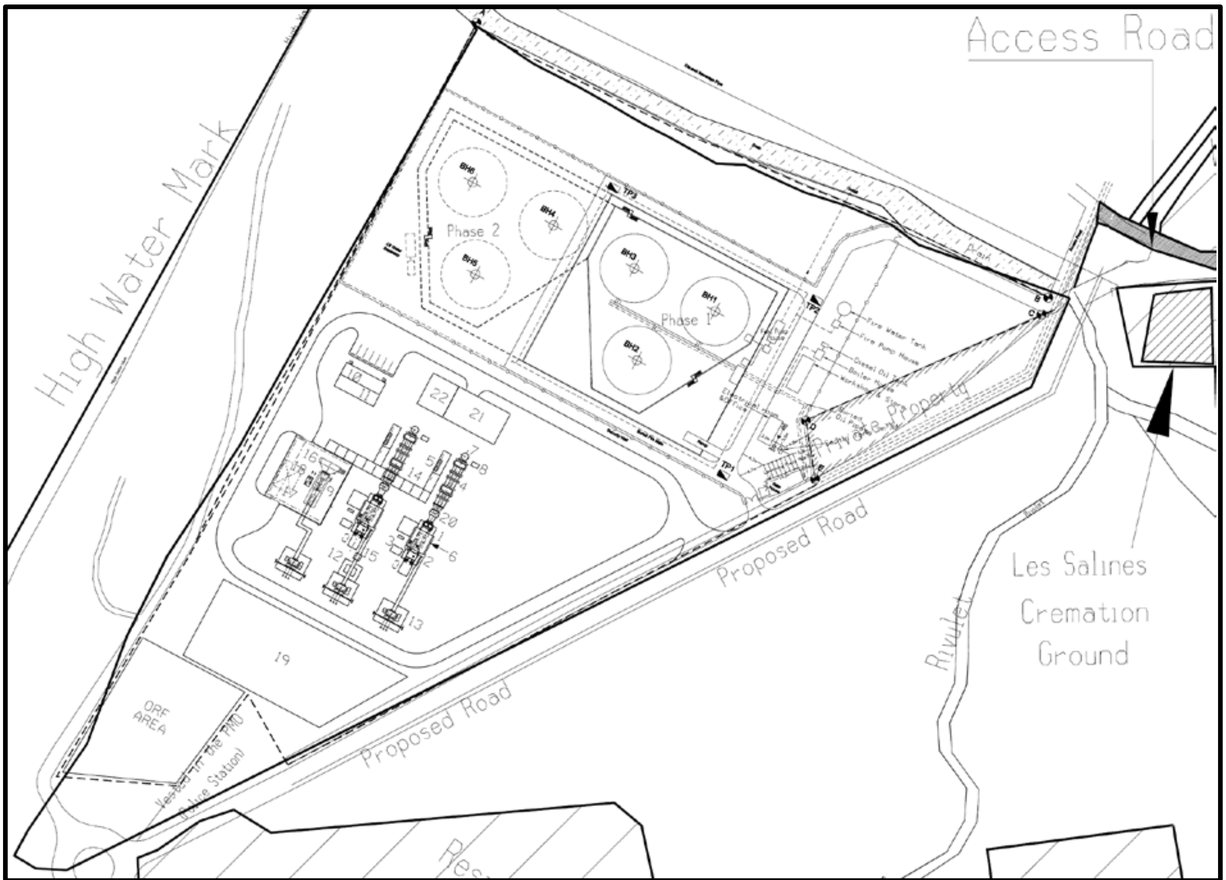
An aerial photograph of the Les Grandes candidate site is presented in Exhibit 4-1.

Exhibit 4-1: Les Grandes Salines Site (Bain des Dames)

CEB owns the site indicated in Exhibit 4-1 and has an option to buy addition land adjacent to the site if necessary. CEB is planning to put six 6,500 m^3 (each) tanks at this site. The site will need to accommodate both the new power plant as well as new six tank farm. The tank farm will support the needs of the additional 4 x 15 MW HFO power plant at Saint Louis and also support the needs for the

Rodrigues Island. Even with the tank farm, the candidate site would have sufficient room for either a combustion turbine or diesel engine power plant of approximately 100MW. This is demonstrated by a preliminary layout for 2x1 LM6000 combined cycle power plant as presented in Exhibit 4-2. A diesel engine plant would also fit within the available space. The purpose of the layout is to demonstrate adequacy of the available space.

Exhibit 4-2: Les Grandes Saline Site with Gas Turbine Combined Cycle Power Plant



1 Combustion Turbine (CT)	9 Steam Turbine Generator	18 Steam Turbine Generator Bridge Crane
2 CT Generator	10 Electric Equipment Area (First Floor)	19 Switchyard
3 CT Oil Cooler	11 Admin / Control Room (Second Floor)	20 Bypass Stack
4 Heat Recovery Steam Generator (HRSG)	12 Auxiliary Transformer	21 Maintenance and Warehouse Building
5 Boiler Feed Pump	13 Step-up Transformer	22 Water Treatment Building
6 Air Intake	14 Utility Rack	
7 Stack	15 Generator Circuit Breaker (GCB)	
8 Continuous Emission Monitoring System (CEMS)	16 Steam Turbine Condenser	
	17 Steam Turbine Laydown Area	

Exhibit 4-3 shows the location of the Les Grandes Salines site along with the existing transmission system and generating stations within Mauritius. The Les Grandes Salines site is located within a kilometre or two of the Fort Victoria and St Louis power station. Connecting the existing transmission line to the Les Grande Salines site should only require a relatively short connecting line[16]. As such, this potential location is favourable from the perspective of interconnection.

Exhibit 4-3: Island of Mauritius Electrical System and Les Grandes Salines

[16] Due to the installed capacity of 107.5MW at the Fort Victoria Power Station, installed capacity of 101.4MW (Wartsila: 41.4MW and 60MW re-development to be commissioned in 2015) at the St Louis Power Station, there may be the need to upgrade to 132kV transmission with the proposed LNG power station located at Les Salines and the LNG Power Station may have to be interconnected at the St Louis high-voltage station, which shall form part of the future 132kV transmission network backbone. Further due to right-of-way issue, the transmission interconnection may be up to three to four kilometres in length, which is still a relatively short interconnecting line.

As shown in Exhibit 4-4, the Les Grandes Salines site is within several kilometres of both the M2 and A1 highways, and within the vicinity of the port. The site itself will require the development of a new access road but of a relatively short distance. From the perspective of site accessibility and transportation infrastructure, the location of the Les Grandes Salines site is favourable.

Exhibit 4-4: Area and Transportation Surrounding the Les Grandes Saline Site

As shown in Exhibit 4-5, the Les Grandes Saline site is undeveloped greenfield site with existing vegetation

Exhibit 4-5: The Les Grandes Saline Site - Greenfield

Exhibit 4-6 also shows that the site is within the 1 km exclusion zone for residential areas, and within the 500 m exclusion zone for coast line. The two concentric circles have a radius of 0.5 and 1 km. As such, utilization of this site for a new power facility would require that CEB apply for a smaller exclusion zone for the site. [12]

Exhibit 4-6: Proximity to Residential Area and Coastline - Les Grandes Saline Site

As illustrated within this section, the Les Grandes Salines site appears to be a feasible site for the new 100 MW power plant considering the following attributes.

1. Available footprint – as illustrated by the General arrangement.
2. Proximity to Transmission line – located within a few km of existing transmission lines.
3. Proximity to Residential area, although permission to be within the normal exclusion zones will need to be obtained.
4. Site Accessibility and transport infrastructure – located near major transportation infrastructure.
5. Land Ownership – Land is leased to CEB, and CEB can acquire additional land.
6. Proximity to the LNG tanker jetty

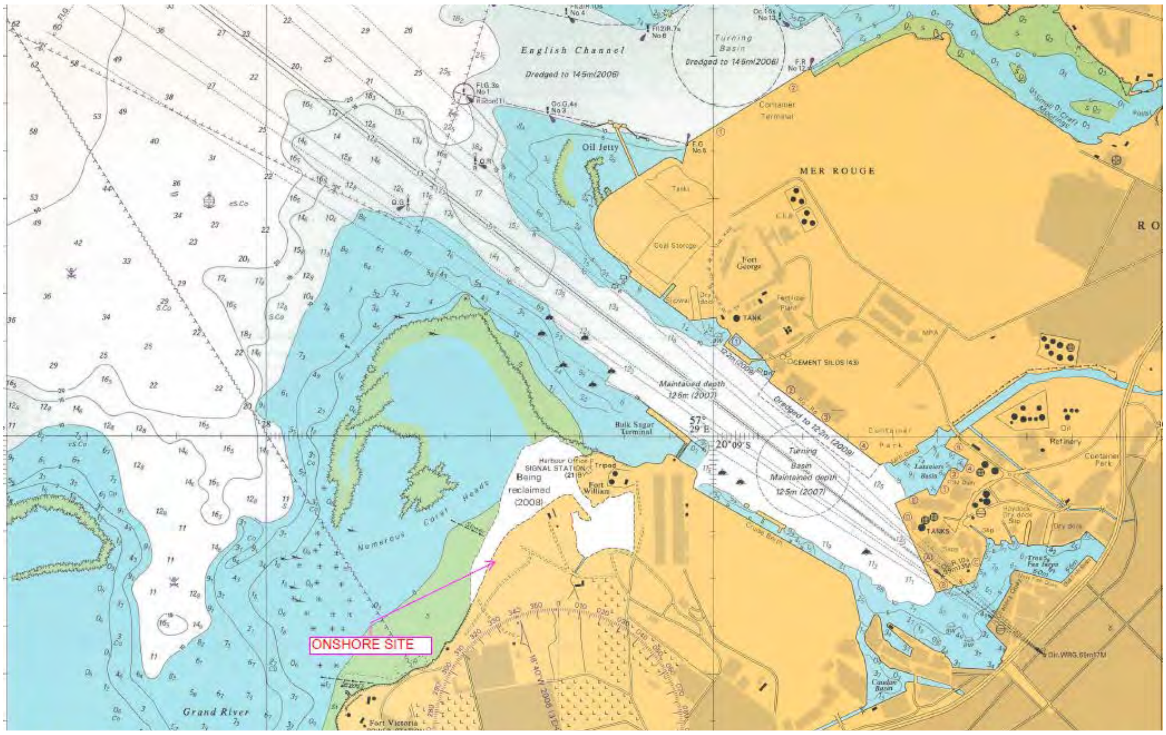
As such, the Les Grandes Saline site looks to be feasible for the addition of a new gas turbine combined cycle power plant as evaluated at this pre-feasibility study level; barring ability to reduce exclusion zone requirements.

4.3.2 LNG infrastructure & Port and Marine Considerations

This section provides a summary of the site coastal and marine conditions based on observations made during the site visit and gathered data and information, as listed below (refer to [18], [20], [22], [23], [24] and [26])

More detailed quantitative Metocean data, some of which may be available from the Mauritius Port Authority (MPA) will be required for any further stages of this project.

Exhibit 4-7 Admiralty chart (Port Louis) and proposed site (Les Grandes Salines, Bain De Dames)



4.3.2.1 Wind

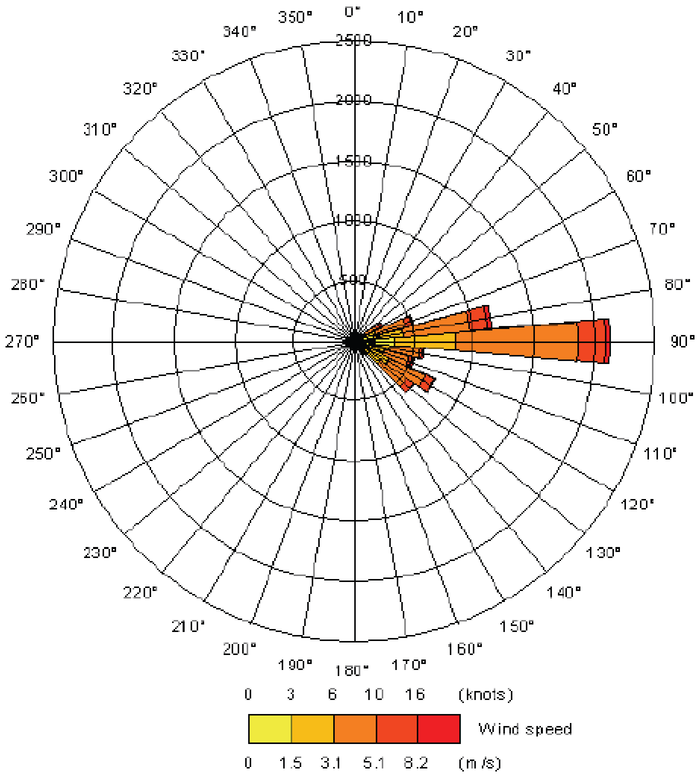
South Eastern Trade winds are the prevailing wind pattern in Mauritius, except for short periods in the summer months when tropical storm approach the island. The trade winds are stronger and more persistent in winter when strong anticyclones pass to the south and close to the island. In the area of Port Louis, the wind pattern is modified by the arc of mountains lying on the eastern side of Port Louis. Prevailing winds are easterlies (40% average of the year) [22]. Moderately frequent winds are experienced for the SE (23%) and less frequent winds from the North East (13%). Winds on average blow from these sectors for 9 months of the year whilst winds from all other sectors are relatively infrequent (1 to 3 %). Calm days occur on average 15% of the time in one year.

Winds show seasonal characteristics, east and south-east winds remain dominant throughout the year but frequency and strength of north and north-western winds increase during the months of December, January and February.

Generally the windiest months are January, February and March, with high winds prevalent in February (mostly occurring from East).

Exhibit 4-8 shows a wind rose extracted from Mauritius Meteorological Station (A meteorological station manned by the personnel of the Mauritius Ports Authority is located on the coast at Fort William). Maximum recorded (non-cyclonic) wind speed are in the order of 13 m/s which occur in average for a very few days a month; most likely wind speeds at the site generally occur in the range of 3 to 8 m/s.

Exhibit 4-8 Wind Rese for Fort William (2006-2007) – source: Mauritius Meteorological Station



4.3.2.2 Wave climate

Wave climate in Mauritius is mainly characterised by wind waves approaching from the south-eastern sectors and southerly swells which are likely not to impact directly the site. However, cyclonic waves which occur occasionally can cause significant damage to coastal resources and infrastructure situated in the surroundings of Port Louis.

Exhibit 4-9 Prevailing direction of swell, cyclone and wind generated waves

The wave climate in deep water off Port Louis is relatively quiet, with waves and swells from open sea occurring approximately 10% of the time.

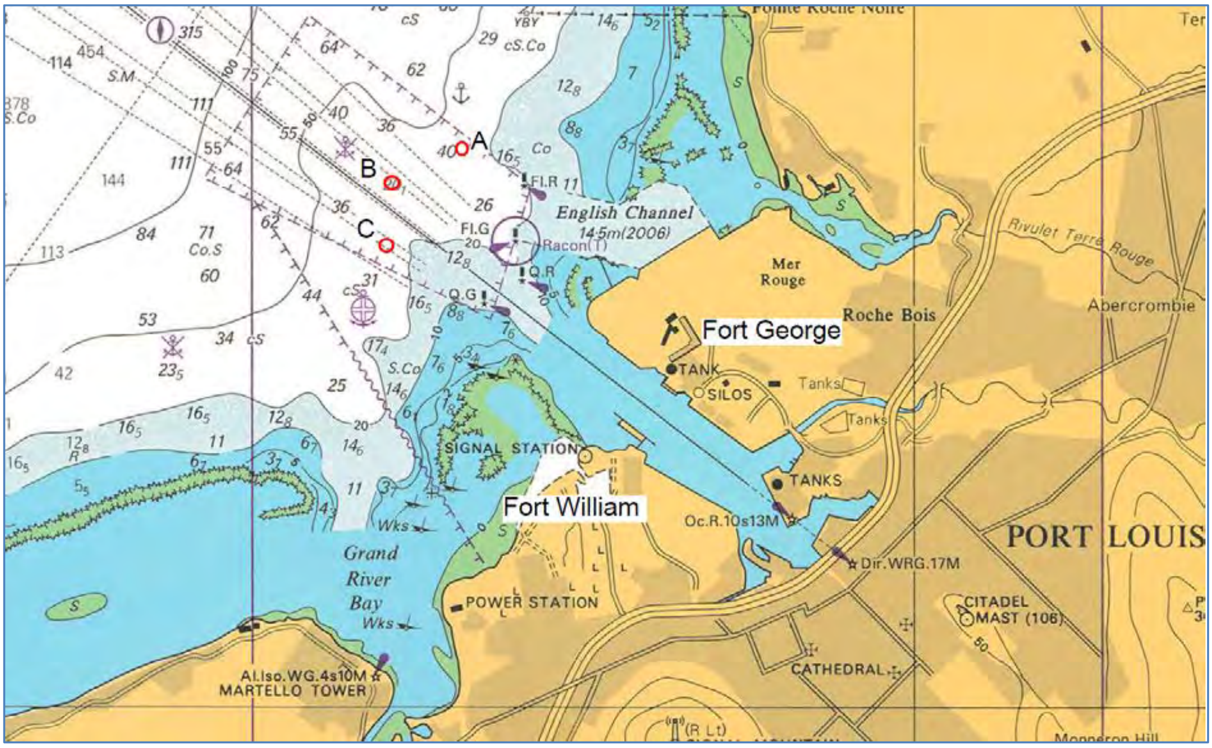
Offshore waves in the vicinity of Port Louis are predominantly from the west. Extreme wave conditions are generated by cyclones, depending on path of the cyclone, its speed, pressure and wind speed (an example of cyclone tracks is shown in Exhibit 4-13).

A table with significant wave events in three-hour storms for inshore and offshore locations has been extracted from [22] (section 6) and is shown in Exhibit 4-10.

Exhibit 4-10 Significant wave height

Return Period	Offshore significant wave height [m]						Significant wave height [m] - propagation to -25m contour		
	SW	WSW	WNW	NW	NNW	NNE	A	B	C
1	5.4	3.5	4.8	5.3	4.2	4.1	4.9	5.1	6.6
10	7.1	4.9	6.7	7.5	5.7	5.5	6.6	7.1	9.9
25	7.8	5.3	7.4	8.3	6.3	6	7.3	7.7	11.1
50	8.2	5.7	7.9	8.9	6.7	6.3	7.8	8.1	12
100	8.7	6	8.4	9.5	7.2	6.7	8.3	8.6	13.2

Exhibit 4-11 Indicative location of Points A, B and C (Sir Alexander Gibb & Partner 1993)



A wave buoy for MPA recorded wave height up to 5.5m during cyclone Daniella at 20m depth; this is likely to have been the most severe cyclone hitting Port Louis.

The following wave heights are recommended for the design of berth structures at Port Louis [22]:

Exhibit 4-12 Recommended design significant wave height

Location	Significant wave height [m]
Berthing structures	5.1
Revetments adjacent to berthing structures	5.1
Reclamation (north of port area), Fort George	3.4
Reclamation (south of port area), Fort William	1

It is noted that the design wave height for the area of Fort William is relatively small when compared with Fort George, although both sites lie within the port area.

As shown in Exhibit 4-11 Fort George is more exposed to wave energy during extreme events, which will penetrate through the harbour access channel, while the site at Fort William is protected by the presence of a coral head and generally a very shallow seabed.

When compared with wave height values given at locations A, B and C in Exhibit 4-10, the expected wave climate at the LNG site is expected to be relatively milder. The offshore site proposed for the LNG terminal (refer to Exhibit 5-13 and Exhibit 5-14) is located approximately 1km south of location C (shown in Exhibit 4-11) in shallower depths of water (approx. 16 mCD); correspondingly wave height is expected to decay as it approaches the shore. Some of the incoming wave energy may however be reflected off the natural reef adjacent to the site and cause local increase of wave height. Additional wave studies will be required to identify the wave pattern at the proposed site and optimise terminal location.

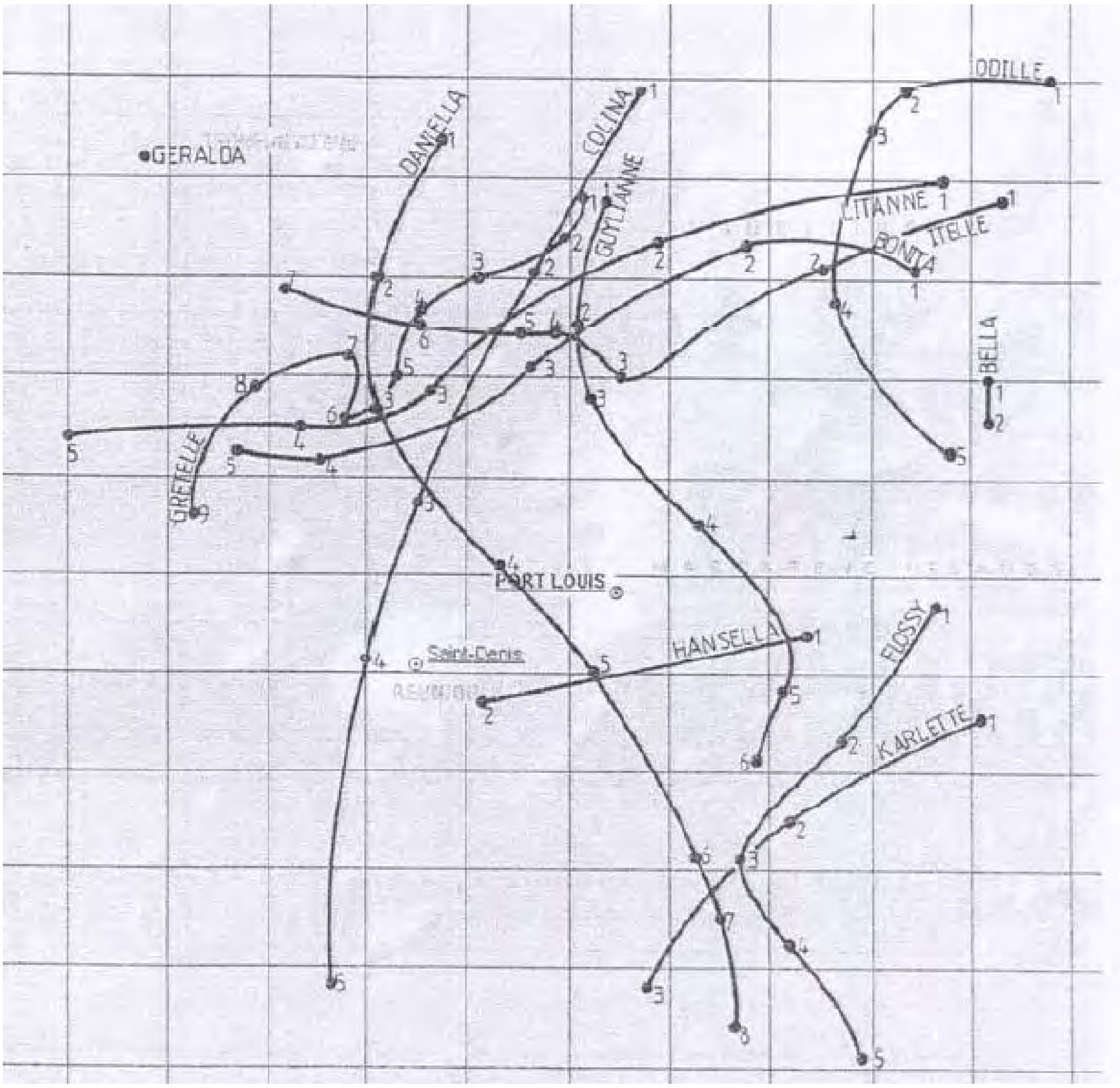
No information was made available on frequent/operational sea states at the time of writing this report. This is however of great relevance for berth availability and downtime assessment and shall be assessed during further design stage.

4.3.2.3 Cyclones

Mauritius is located in the cyclone belt of the south-western Indian Ocean and is subject to seasonal tropical cyclones between the months of December and March/April. Cyclones are characterised by low pressure and high wind speed conditions. From records available at the Mauritius Meteorological Services, during 1960-70, 39% of cyclones were classified as “Weak”, 42% as “Moderate” and 19 % as “Strong” with gust speeds over 80 km/h, [22].

On average, about 10 cyclone formations occur during the tropical cyclone season (1st November to 15th May) with a range between 2 and 16 [22] [28]. January and February are the two most active cyclone months. Typical tracks of most cyclones are parabolic in shape with an initial WSW direction followed by a southerly course which often brings the system near Mauritius.

Exhibit 4-13 Tracks of Cyclones 1980-1990. Source [28]



Mauritius has been visited by major cyclone on an average frequency of one in about 15 years, although it should not be thought that there is a regular succession of cyclones and there is considerable irregularity in their occurrence. According to IPPC [29], it is expected an increase in the frequency and intensity of future tropical cyclones, with larger peak wind speeds and heavier precipitation associated with the ongoing increase of sea surface temperature.

Cyclones coincide with the generation of extremely high wind velocities. Between 1945 and 2003, 51 cyclones were identified in Mauritius with wind gusts exceeding 100 km/hr. During cyclones Carol (1960), Jenny (1962), Gervaise (1975) and Claudette (1979) average velocities approaching 140 km/hr were recorded on Mauritius with maximum gust velocities as high as 260 to 280 km/h (measured at Fort William).

Through the statistical analysis of 100 years of recordings the Mauritius Meteorological Service have adopted the following 100-year occurrence wind speeds for design purposes:

- Average hourly speed = 125 km/h
- Maximum 3 second gust = 280 km/h

These values (which apply to normal exposure conditions) should be adopted for structural design at the selected site.

In addition to wind speed, the duration of wind speed levels is also an important factor as it influences oceanographic conditions in the vicinity of cyclones. The CSIR (1992) summarized recorded durations for the exceedance of different wind speeds during four cyclones as presented in Exhibit 4-14.

Exhibit 4-14 Cyclone Wind duration

Cyclone Date	Wind speed					
	64 km/h	81 km/h	97 km/h	113 km/h	129 km/h	145 km/h
29 April 1892	7	3	2	1	0	0
16 January 1945	16	5	0	0	0	0
19 January 1960	13	0	0	0	0	0
28 February 1960	11	7	2	2	1	0

The highest gust speeds registered by the meteorological services during cyclone events for the period 1960 to 2002 are summarized in Exhibit 4-15

Exhibit 4-15 Cyclone wind speed measurements

Location	Cyclone Event							
	Carol Feb 1960	Jenny Feb 1962	Gervaise Feb 1975	Claudette Dec 1979	Hollanda Feb 1994	Daniella Dec 1996	Davina Mar 1999	Dina Jan 2002
Pamplemousses (north west)	238	196	185	201	196	105	131	147
Fort William (Port Louis)	**257**	**277**	**238**	**221**	**216**	**124**	**173**	**209**
Plaisance (south east)	209	151	204	221	156	155	169	148
FUEL (east)	238	138	169	200	129	95	140	127
Medine (south west)	256	208	204	174	212	147	125	169

A drastic change in wind direction occurs temporarily when a cyclone passes to the north and west of Mauritius. Cyclonic winds, gusting to more than 120 km/h from the north-west sector opposite to the prevailing wind then influence the western coast. This occurs at least once every 5 years.

The Mauritius Port Authority and other authorities have recommended the use of basic wind speed of 300 km/h (83 m/s) for recent projects.

4.3.2.4 Water level

The tidal regime for the coast of Mauritius is broadly representative of natural open sea level as a result of the absence of adjacent landform features and the island's limited continental shelf width. Tides are semi-diurnal (two low tides and two high tides daily) with an average of 0.50 m range occurring during spring tides and a much smaller amplitude of the order of 0.20 m during neap tides. However, during annual extreme (equinox) spring tides (March and September) the tidal range could be as much as 0.85 m. Very low water level also occurs in exceptional cases and water level can drop by more than 1 m below mean sea level

Water levels recorded in metres above Chart datum at the proposed location have been extracted from the Admiralty chart and are as follows:

- M.H.W.S.= + 0.7 mCD
- M.H.W.N = 0.5 mCD
- M.L.W.N = 0.4 mCD
- M.L.W.S = 0.2 mCD

Sea-Level Changes during Cyclone Events

In case of passage of cyclones in the vicinity of Mauritius, the combined effects of two factors - wind forcing and pressure difference - are responsible for storm surges leading to abnormal rise of sea-level [26].

Exhibit 4-16 shows the height of the water-level at its peak, together with data recorded during the passage of tropical cyclones Colina, Hollanda and Daniella.

Exhibit 4-16 Recorded Water level increase during cyclones (an comparison with Tsunami)

Date	System	Surge (Rise of mean water level above prediction)	Highest water mark above mean sea level	Mean range of Seiches	Period of Seiches
3 Jun.1994	Tsunami wave signal	17.5 cm	33 cm	24 cm	2 min
18-19 Jan 1993	Tropical Cyclone Colina	36.0 cm	74.7 cm	27 cm	7 min

Date	System	Surge (Rise of mean water level above prediction)	Highest water mark above mean sea level	Mean range of Seiches	Period of Seiches
8 Feb.1994	Tropical Cyclone Hollanda	41.0 cm	-	15 cm	6 min
8 Dec.1996	Tropical Cyclone Daniella	22.9 cm	66.3 cm	34 cm	7 min

During the passage of tropical cyclones in the vicinity of Mauritius, the characteristics of seiches also (standing wave generated within the port enclosed area) change in the Port area. Abnormal seiches were recorded during passage of tropical cyclones and are shown in Exhibit 4-16.

Exhibit 4-16 also shows the record of water level during the tsunami that followed the earthquake on 2 June 1994 off Java which travelled the whole length of the South Indian Ocean to reach Rodrigues and Mauritius. It is noted that the rise in the mean water level during the tsunami was not too pronounced compared to the situation during cyclone events, however during a tsunami the associated currents are likely to be strong enough to impact on floating structures, damage piles, and break mooring lines and these effects may be significantly more devastating than the water level increase.

4.3.2.5 Currents

Mauritius is located within the South Equatorial Current which is essentially wind-driven. Prevailing offshore current field is southerly (alongshore) along both the east and west coast of the island, and from east to west along the south and north coast. Grundlingh (1989) reports surface current speeds varying between 0 and 0.6 m/s and an average speed of about 0.25 m/s as derived from free-drifting satellite-tracked buoys.

The tidal water level variation (typically 0.5 m) is accompanied by horizontal tidal currents, distinguishable from other currents due to their periodic nature. Typically offshore tidal currents change direction continuously, causing an anti-clockwise rotating current in the southern hemisphere. The net current will typically be dominated by the ambient South Equatorial Current.

Current measurements have been conducted during studies for the Baie du Tombeau marine outfall, only few kilometres north of the proposed site, and indicated dominant south-westerly net currents, with occasional reversal close to high tide during spring tide conditions. Typical current speeds were in the range 0.05 m/s to 0.3 m/s. at the surface. A gradual reduction in current speed with depth was observed with mean current speed reducing from 0.15 m/s at the surface to 0.07 m/s at 24 m depth. Current speeds of the same order are noted in Sogreah (1991) in the vicinity of Pointe aux Cannoniers and Cap Malheureux, both located further North, with a general south-westward flow.

4.3.2.6 Characteristics of the Seabed

The geology of Mauritius is dominated mostly by deposits of basaltic lavas following volcanic activities which occurred during two distinct periods: a younger volcanic series aged between 0.025 and 3.5 million years B.C. and an older volcanic series aged between 6.8 and 7.8 million years B.C.

A large amount of the port area at Port Louis has been the result of extensive reclamation works which overlies natural deposits.

For the purpose of the pre-feasibility study geological and geotechnical information at the selected site have been derived from an initial desktop review of available information. A number of boreholes logs extracted from the geotechnical site investigation of the cruise berth terminal were provided from our local partner SJP and some additional valuable information has been extracted from a study recently undertaken on the extension and strengthening of the Mauritius Container Terminal (MCT) located at Mer Rouge, Port Louis.

The top layer of the seabed is mainly made of loose sand and soft marine soils (silt, clay & sand) and has a highly variable thickness (from 20 to 50 m thick); this overlies a bedrock unit which underlies the entire port area with varying elevation (from -12 to -62.5 mCD).

A close look at the borehole logs reveals that the local subsoil generally consists of four soil strata:

- Marine deposits: Soft to firm clay interlayered by silt, sandy silt organic material and loose sand
- Medium-dense sand and/or firm clay
- Cemented coral, shells, limestone and calcarenite
- A deep moderately to highly weathered basalt layer (with closely spaced joints)

Some layers of gravel and cobbles were also found at the cruise terminal.

Exhibit 4-17 Photo taken at Les Grandes Salines nearshore site showing the top sandy-clayey stratum with presence of gravel and larger rock material.

4.3.2.7 Site Topography

The area around the designated project site consists of flat land bordering the harbour up to a maximum altitude of approximately 2.5mCD [22] [28]. A number of land filling operations have taken place around the harbour area using dredged material extracted from the deepening of the navigational channel. A considerable amount of material is still stockpiled at the site for proposed future reclamation in the area.

Exhibit 4-18 Ongoing reclamation works - 1

Exhibit 4-19 Ongoing reclamation works – 2

Exhibit 4-20 Stockpiled dredged material for land filling operations

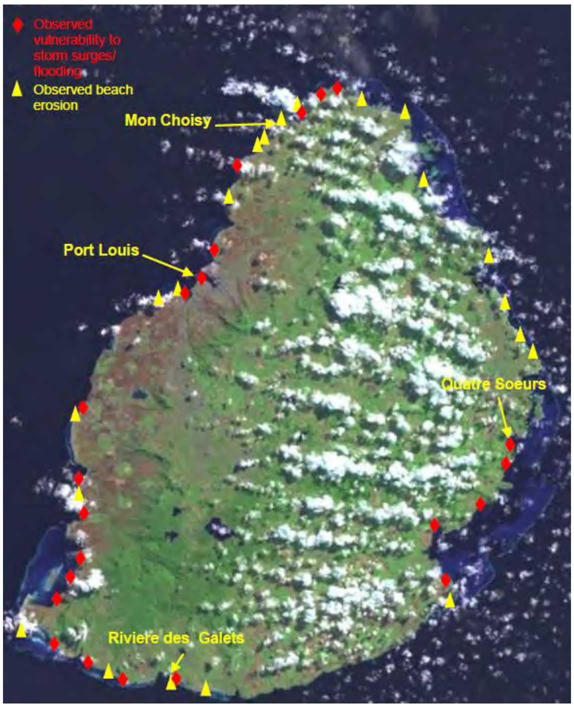
Considering that the proposed location is a relatively low-lying coastal area, cyclone and storm induced surge phenomena are likely to cause inundation of the onshore proposed site.

4.3.2.8 Seabed Sediments and Coastal processes

The Mauritian coastal zone stretches over a distance of about 322 km. Some portion of the coastline is experiencing erosion although most of the island is surrounded by fringing coral reefs [19], which protect against persistent wave action and frequent cyclones.

Exhibit 4-21 indicates locations particularly vulnerable to beach erosion and/or risk of storm surge flooding (CSIR, 2001) and [19] and consequently pronounced morphological changes as a result of natural causes and anthropogenic activities [23]. This is however not the case for a significant portion of the coastline which is protected by the presence of a reef.

Exhibit 4-21: Mauritius Coastal Vulnerability Map (source: UNDP Mauritius).



The reef forms a natural reef-lagoon-beach system comprising a steep reef front and a longer shallow reef plateau following the crest (also called coastal lagoon) which reduces the incoming wave energy.

The reef-lagoon-beach system consists of four main components:

- Reef (front and flat);
- Lagoon;
- Active beach;
- Coastal dune and vegetation.

Together, the active beach, the coastal dune and vegetation comprise the dynamic beach zone.

The health and robustness of a beach and its ability to survive natural forces is dependent on the health of all four parts mentioned above. The degradation of any part of the system will disrupt a fine balance and lead to the onset of irreversible erosion [19].

Exhibit 4-22 describes the beach protection benefits provided by the four principle components of the reef-lagoon-beach system.

Exhibit 4-22:Beach protection benefits for Mauritian coastlines provided by a healthy reef-lagoon-beach system.

System Component	Protection Provided
Reefs	Reef front and wide, shallow reef flat provide primary protect from persistent wave attack. In W.F. Baird and Associates (2003) study of Mauritius, it was found that in almost all cases, the wave height was reduced by 90% in the process of crossing the reef.
Lagoons	The lagoon corals and associated biological community supply the majority of the sand for the island's beaches. Affecting this sand supply could lead to irreversible erosion. The computer models established by W.F. Baird and Associates (2003) depicted dissipation in wave energy reaching the beach due to lagoon corals.
Beaches	The beach further dissipates wave energy that is able to cross the reef and lagoon.
Coastal Dune and Vegetation	Sand dunes store excess beach sand and serve as natural erosion buffers, protecting coastal properties during storms. Healthy dunes should be vegetated by endemic species as they assist in trapping wind-blown sand and are able to recover quickly from erosion events.

Exhibit 4-23: Overview of potential site location.

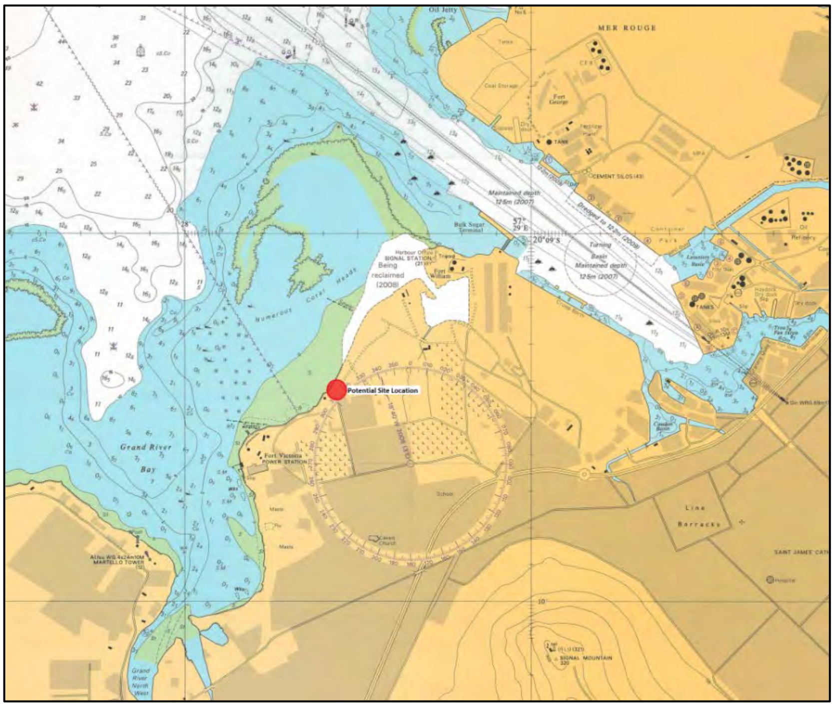


Exhibit 4-23 displays many of the features surrounding the potential site location. Approximately 900 m from the potential site location, in a north and north-west direction, a reef extends in a half circle shape. Approximately 600 m offshore from the selected site the water depth suddenly reduces from approx. 11m to 3m CD and subsequently lowers to less than 2mCD along a 500m strip approaching the shoreline. We also see that “numerous coral heads” are to be found in the lagoon region between the reef and the near-shore.

Exhibit 4-24: Picture of potential site location foreshore and primary dune system from December 2013 site visit.

Exhibit 4-24 depicts a sandy beach at the potential site location.

A number of investigations on sediment size and quality have been undertaken over the years. A first investigation was conducted for the development of the container terminal in 1996, and some additional sediment analysis data were obtained in 2011 from a dive survey in the Port Area. Most of the samples can be classified as fine to medium marine carbonate sand. Initially a sediment size of D50=0.12mm was determined, but the survey undertaken in 2011 showed presence of coarser sediments.

During the marine survey a few samplings were also extracted in the area between Les Grandes Salines and Bain des Dames; these are shown in Exhibit 4-25:

Exhibit 4-25 Sediment sample size at the nearshore area at Les Grandes Salines site

Site	Sieve size [mm]	% Retained
12	0.3-1.18	76.1
13	0.3-1.19	83.4
14	0.6-2.36	43
15	25-50	85.4

Exhibit 4-26 Location of surveyed sites in the vicinity of LNG potential site at Les Grandes Salines

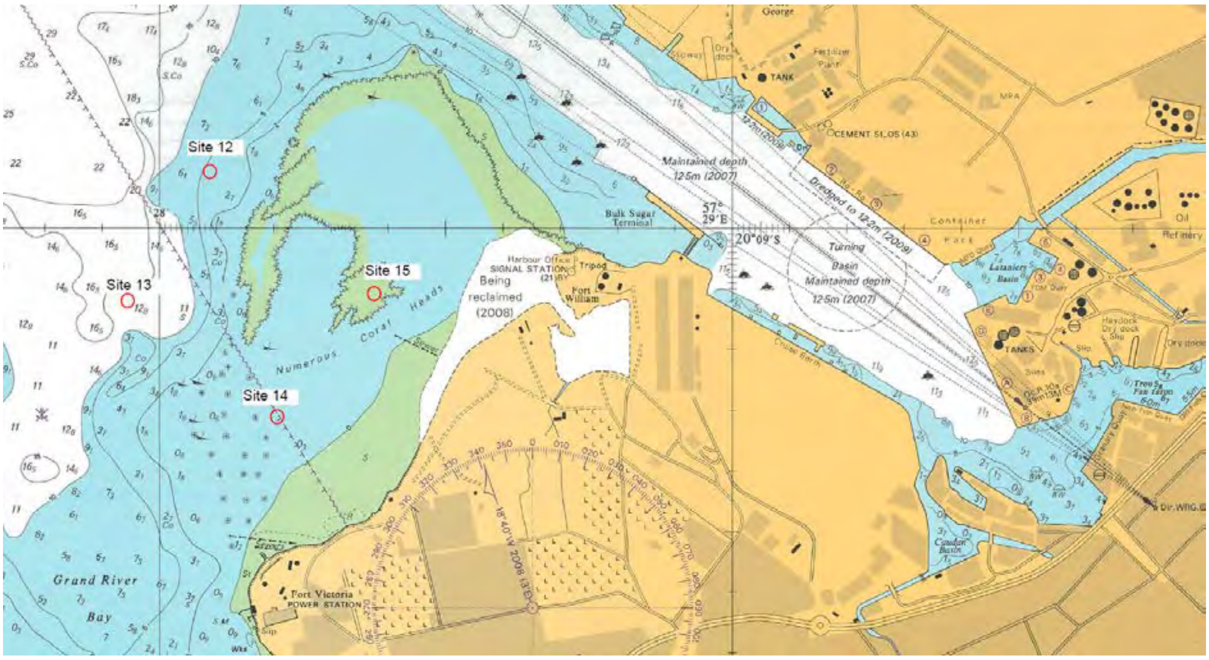


Exhibit 4-25 describes the configuration of the typical sediment size found in the near-shore region of the study site. Exhibit 4-24 also describes a vegetated dune system with grasses and vegetation – although a local specialist would be required to determine if the species depicted are endemic or not.

Therefore Exhibit 4-23 and Exhibit 4-24 depict the four components that form the reef-lagoon-beach system that act to dissipate offshore wave energy as it travels through the near-shore. The system that W.F. Baird and Associates (2003) states is important to protecting the Mauritius' coastline is exhibited at the potential site location, although long term monitoring would be required to determine the health of the system.

Furthermore, as stated in Section 4.3.2.2 the potential site is not directly impacted by the dominant wave direction; therefore, as the initial offshore wave energy is likely to be lower and accounting for the energy dissipation effects of the reef-lagoon-beach system, it is expected that the potential site would have less vulnerability to erosion than other regions in Mauritius where these two factors are not present.

Large erosion events may occur due to Mauritius location in the cyclone belt of the south-western Indian Ocean. Sections 4.3.2.3 to 4.3.2.4 outline the potential influence of a cyclone; including high wind speeds, sea-level set-up and changes to the wave climate. Increases or intensification of the aforementioned components could result in a significant erosion event at the study site.

Healthy beaches recover fully from erosion that occurred due to a cyclonic event through a combination of wind and wave forces in the hours, weeks and months following [19]. As stated previously, the implementation of a long term monitoring program would be required to determine the health of the beach at the study site, and therefore its ability to respond to a significant erosion event.

In conclusion, the site is less vulnerable to erosion than other regions, except, potentially, due to a cyclonic event, or should dredging or other construction activities occur in the region of the site. Detailed sediment modelling and coastal processes studies will be required during further stages of design to assess the vulnerability of this specific site and identify suitable countermeasures.

4.3.2.9 Discussion and Recommendations

The proposed onshore location for the LNG terminal (at Bain les Dames, Les Grandes Salines) has been assessed with reference to the main environmental factor and associated risk.

The presence of a shallow coral reef helps preventing coastal erosion and protects the shoreline from the wave action. Wave conditions in deep water, at further distance from the shore, are generally mild but may suddenly change in case of severe cyclonic events.

A number of cyclone induced inundations have been recorded over the years at the adjacent container terminal and are likely to cause flooding at the proposed low-lying site.

Hydrogeology and hydrology of the site and surrounding area should also be analysed during further design stage to identify any impacts associated with hydrological and hydrogeological risk. Cyclones may significantly and rapidly affect surface water runoff and groundwater flow and potential implications / consequences on site vulnerability should be considered.

5. PORT AND MARINE ASSESSMENT

5.1 Introduction

The LNG marine infrastructure would generally include an LNG offloading berth, a navigational area with an access channel and a manoeuvring area and a number of gas processing facilities which are dependent on the terminal configuration.

A preliminary concept definition of marine facilities requirement was undertaken during this prefeasibility study. This includes:

- Assessment of existing Marine Infrastructure at Port Louis and possibility to accommodate berthing of LNG carriers
- Evaluation of a shore based and a floating storage and regasification terminal for LNG import

An initial high level assessment of the main infrastructure requirements is undertaken for both concepts and correspondingly a preliminary cost estimate and construction schedule is determined in Section 5.5 drawing on elements from this Section and Section 3 (the terminal and storage discussion).

Based on this initial evaluation (as discussed in Section 3, this Section and Section 5.5) and for the purpose of the prefeasibility study, the FSRU option is concluded as the preferred alternative and will be adopted as base case for the economic and financial modelling (Section 8).

5.2 Existing Marine Infrastructure Assessment

The only existing and main marine infrastructure in Mauritius is Port Louis harbor, situated on the north-west coast of the island.

The port comprises three main terminals

Terminal 1 including:

- A multipurpose terminal consisting of 3 quays where various types of cargo are handled, such as black oil, fuel oil, edible oil, general cargo, wheat, maize, molasses, soya-bean, meat, passengers and inter-island trade. Berthing lengths range from 135 to 210 m whereas the dredged depth ranges from 9 to 12.2 m.
- Fishing terminal. 3 quays are used by the fishery industries with one quay privately operated. The berthing length varies between 160 and 310 m and the dredged depth ranges from 4.6 to 8.0 m.

Terminal 2 which includes:

- Multi-purpose terminal with 4 quays available to handle different types of cargo, such as black oil, coal, containers, fertilizers, LPG and general cargo. The berthing length ranges from 123 to 185 m while the dredged depth is 12.2 m.
- Bulk sugar terminal with 210 m of berthing length and 12.2 m of dredged depth used to handle bulk sugar and black oil.

- Fishing terminal. Consists of one quay with 118 m of berthing length and 7 m of dredged depth used by the fishery industry.
- Cruise Jetty to accommodate the fast growing segment in the global tourism industry. The berthing length is about 124 m with a dredged depth of 10.8 m.

Terminal 3 includes:

- Container terminal that comprises two quays of 280 m berthing length and 14 m dredged depth to handle cargo vessels.
- Oil Jetty constructed at Mer Rouge as a dedicated facility for petroleum products to enhance safety and security in Port Louis. Dredging depth is set to 14.5 m accommodating berthing of large tankers up to 50,000 DWT. The Oil Jetty is equipped with 8 Pipelines and has a throughput capacity of about 4 Million Tons per annum.

Expansion plans are currently being developed. MPA's current development plans include the extension of the container terminal and the creation of additional facilities for fishing vessels.

The existing oil jetty loading platform configuration and the trestle structure have been assessed with regards to the possibility of accommodating LNG vessels. As result of the preliminary assessment and the visual inspection the existing jetty is deemed not adequate for berthing of medium to large LNG vessels given the relatively small size of the loading platform. The existing platform does not allow enough room for locating the necessary equipment for loading/offloading of LNG, the trestle will need to be widened and possibly retrofitted to accommodate placement of cryogenic pipeline and the present dolphin configuration may have to be revisited to assess its suitability for mooring of LNG vessels. Additional considerations could be made at later design stage if design vessel range and storage requirements were revised, yet at this stage it is likely that a dedicated jetty for LNG import will have to be installed.

Exhibit 5-1 Existing Oil Jetty platform

5.3 LNG Import Requirements

Actual and projected consumption of LNG is 0.3 MTPA in year 2018, and 0.45 MTPA in year 2022. On the basis of this demand projection, there will be:

- 6 unloading per annum in Year 2018 based on 0.3 MTPA LNG Consumption
- 9 unloading per annum in 2022 based on projected demand of 0.45 MTPA LNG Consumption

If functional requirements of 1 MTPA LNG demand are assumed for this pre-feasibility study, the data for unloading requirements is tabulated in Exhibit 5-2 below:

Exhibit 5-2: Functional requirements

Item	Assumption
Throughput	LNG: 1 MTPA (114 tph, 250 m^3/h)
Range of vessels	Assume LNG membrane or moss type Containment system in vessels Design Storage Capacity: 173,000 m^3
Size of LNGC & No. of unloadings per year	Assuming 125,000 to 150,000 m^3 LNGC, 250 m^3/h LNG continuous load, number of unloadings/ year are 18 unloading/year (i.e.once every 20 days)

5.4 Design Considerations

5.4.1 Navigational requirements

5.4.1.1 Water Depth

Sufficient water depth is required for the vessels at the berth and in approaches to the berth. In general the design should ensure sufficient underkeel clearance when the vessel is fully loaded and at all states of the tide. Thus the minimum depth required is referenced to water depth at Lowest Astronomical Tide (LAT).

PIANC (Permanent International Association of Navigation Congresses) standards has been used in the desktop study to determine initial channel and turning basin depth, width and alignment. Navigation studies will be required to determine more accurate approach channel and turning basin dimensions for the range of vessel types and also to determine limiting conditions of waves, current and tides. Under-keel clearances will also have to be confirmed once additional information on vessel size, environmental and sea-bed characteristics will be available.

Exhibit 5-3: Typical Design Vessel

	Capacity [m^3]	LOA [m]	Beam [m]	Laden draught [m]
Membrane type FSRU	173,000	290	45.8	12
Moss Type LNGC	125,000 to 150,000	290	49	11.5

The channel depth has been designed to accommodate the fully laden draft of the largest vessel subject to wave action during all tides. It is assumed that maximum laden draft for both LNGC and FSRU is set to approximately 12.0m. The channel depth shall also allow for sedimentation build up and survey accuracy allowance. Typical dimensions for turning basin, navigation channel width and depth are presented in Exhibit 5-4.

Exhibit 5-4: Typical Dimensions for Approach Channel and Turning Basin.

Dimensions [m]		
Underkeel clearance berth	10% to 20% of vessel draft	13.8
Underkeel clearance Access	30% of vessel draft	16
Turning basin	2 to 3 x LOA	787.5
Channel Width	5 to 8 x B	325

With reference to the concepts described in Section 3.4.1 and 3.4.2; Exhibit 5-5 shows typical berth pocket dimensions for a land based LNG single berth and a dual berth FSRU respectively:

Exhibit 5-5 Berth pocket dimensions

Dimensions [m]		
Single berth LNG	1.25 x B by 1.25 x LOA	Approx. 400 x 65
Dual berth FSRU	2.5 x B + jetty head width by 1.25 x LOA	Approx. 400 x 250

Values shown in Exhibit 5-5 are purely indicative to the space required by an LNGC during unloading; additional considerations on vessel maneuverability and berth access will be made during further design stage followed by navigational simulation which will confirm berth pocket dimensions.

5.4.1.2 Navigation

Space for safe navigation onto and off of the berth has to be provided. For the purpose of the prefeasibility study a minimum approach channel width of 6.5xB (as being B the beam of the design vessel) is recommended, as shown in Exhibit 5-4 based on PIANC 1997 guidance [15]. Taking into consideration the LNG design vessels as per Exhibit 5-11 a channel width of 325 m is proposed.

As noted above in respect of the PLF berth pocket dredged depth, the details of the LNG vessel fleet (which is the driver for channel width) is uncertain at this stage therefore it may be possible to optimize the channel width in the following design phases.

A minimum of three tugs shall be available to assist during berthing/unberthing operations and at least one tug will remain in stand-by in proximity to the berth during loading / unloading operations as well as throughout the entire period when the vessels are moored at the berth.

5.4.2 Loading platform

Due to the north westerly prevailing wave and wind direction it is envisaged that the jetty will have a North-West South East orientation. This orientation is preferred to minimize the transverse wind and wave force on both the FSRU and the moored LNGC which will significantly affect the uptime of the facility.

Given the reduced annual production requirement and consequently the relatively low minimum requirement for berth operability, no breakwater is deemed to be necessary and no approach to the berthing facility will be allowed during bad weather.

5.4.3 Mooring

The Mooring arrangement would follow recommendations from OCIMF and SIGTTO, deploying breast-lines and spring-lines. All mooring lines would be equipped with soft (nylon) tails (typically at least 11 m in length) to allow a proper behavior of the mooring system under wave and wind induced dynamics. All mooring lines should be pre-tensioned, to ensure that resulting vessel movements will stay modest whilst alongside. Mooring line loads would be measured on the jetty, and relayed back to the carrier on request.

The master of the ship will receive a berthing system pager, if required, from the terminal cargo officer, which gives online information about tension of mooring lines and relative distances of the LNGC to the jetty.

Under normal conditions lines will be released locally at the Quick Release Hooks (QRH's) on the various dolphins. Upon exceptional request from the Carrier the QRH's can also individually be released remotely from the jetty monitoring building.

As mentioned earlier, it is common that during loading a tug is on stand by and a second tug (or guard vessel) patrols the exclusion zone. This would allow the LNGC to be moved off the berth in an emergency event and the patrolling tug would be able to intercept vessels that would be on collision course.

5.4.3.1 FSRU Mooring systems

a. General

The mooring system of the FSRU needs to ensure it is able to be moored safely and is suitable for the metocean conditions at the location. The mooring also needs to facilitate the transfer of LNG from the LNGC to the FSRU, which requires the use of equipment suitable for operation at cryogenic temperatures. Within this Section several types of mooring systems that have been used or proposed for offshore LNG facilities are examined and described, including:

- Jetty mooring;
- Disconnectable buoy mooring;
- External turret mooring;
- Soft-yoke mooring.

b. Jetty Mooring

The jetty mooring system comprises a jetty with:

- The FSRU moored to one side and the LNGC moored either on the opposite side – here the 2 sets of rigid loading arms would be mounted on the jetty. High Pressure (HP) gas is export via flexible riser from the FSRU or HP gas loading arm to the jetty.
- The FSRU moored to the jetty and the LNGC moored side-by-side to the FSRU- here the rigid loading arms would be mounted on the FSRU (This is a more recent development type, High Pressure (HP) gas is export via flexible riser from the FSRU or HP gas loading arm to the jetty.
- The LNGC moored to the jetty, with LNG export by rigid loading arms mounted on the jetty.
- The fixed jetty can be constructed using either
    - Steel piles installed on site;
    - Pre-fabricated jacket structures constructed onshore. The jacket structures are then floated out and installed on site.

The jetty includes mooring/fendering structures to moor the FSRU and LNGC, with rigid loading arms used for LNG transfers, and a flexible riser for high pressure gas export.

The below pictures illustrates this concept based on an offshore LNG regasification vessel (FSRU).

Exhibit 5-6 Jetty mooring at Guanabarra Bay, Rio De Janeiro, Brazil

Exhibit 5-7 shows a typical FSRU side by side mooring configuration:

Exhibit 5-7 FSRU side by side mooring

c. Disconnectable Buoy Mooring

This concept is based on the use of a disconnectable buoy mooring (DBM) system. The DBM system allows the FSRU to be disconnected from the buoy and sail away from the buoy site. When the buoy is disconnected from the FSRU, it sits sufficiently far below the wave affected zone and water surface such that it will not come into contact with passing ships/vessels.

To reconnect the buoy, the FSRU sails directly over the buoy and pulls in the messenger line attached to the buoy to winch the buoy up. Once the buoy is in place, it is held to the FSRU via locking mechanisms. Swivel bearings interfacing the buoy and FSRU allows the FSRU to weathervane (i.e. align) to the prevailing environmental condition such that roll motions on the FSRU are sufficiently minimized.

Natural gas travels from the FSRU to the subsea pipeline via a PLEM and subsea riser, and then via a series of gas piping and gas swivels (located in the disconnectable buoy).

Exhibit 5-8 Disconnectable buoy mooring

d. External Turret Mooring

The turret mooring system is comprised of a turret to which mooring lines and flexible/dynamic risers connect to. The turret includes a swivel bearing which allows the FSRU to weathervane with the prevailing weather conditions. The turret could be internally mounted (within the hull of the FSRU) or externally mounted.

Exhibit 5-9 FSRU + Turret Mooring

e. Soft-Yoke Mooring Tower

The soft yoke mooring system is comprised of the following structures:

A soft yoke structure attached to the FSRU which provides restoring forces to “move” the FSRU back to its equilibrium position;

A mooring tower connected to the soft yoke structure on the FSRU. The mooring tower essentially holds the FSRU on location and allows the FSRU to weathervane;

Soft-yoke mooring towers are usually not used where the 100 year return wave condition exceeds a significant wave height of 7m.

The interface between the mooring tower and soft yoke structure is comprised of bearings and gas swivels. The gas travels from the FSRU through the swivels, through piping on the mooring tower, and into the subsea pipeline. The soft yoke mooring system permanently moors the FSRU on location and is not designed to be disconnected on a regular basis.

Exhibit 5-10 Soft yoke mooring

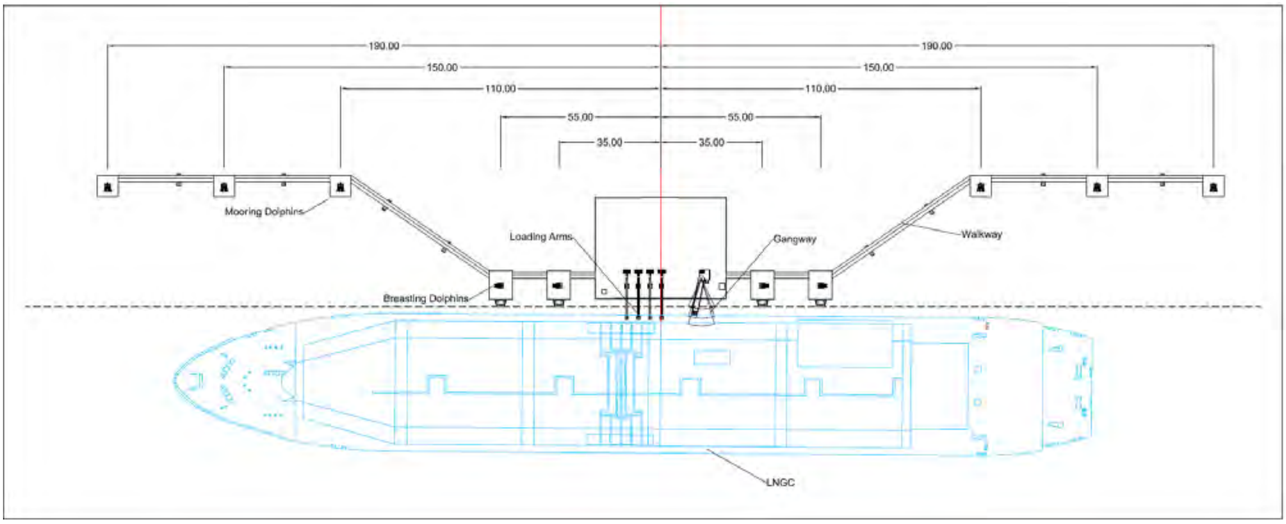
f. Discussion

A number of alternative mooring systems have been presented although an accurate evaluation of the suitability of the different systems and the selection of the most appropriate technology for this specific case study will be carried out during following design stage, when more detailed site information will be available. For the purpose of the pre-feasibility study a traditional dual berth jetty type will be selected as this is a robust and flexible structural solution with a proven track record which is likely to achieve target performance for berth availability.

5.4.3.2 LNGC Mooring Configuration

Based on a preliminary design vessel range as given in Exhibit 5-3 a preliminary configuration based on typical mooring and berthing guidelines [16] and a fixed jetty structure is derived. This is shown in Exhibit 5-11:

Exhibit 5-11: Initial assessment for LNG berth mooring configuration



5.4.4 Exclusion, Safety Zones and Risk management

The design should devote considerable attention to any risk that the LNG terminal may devote to the port environs. This is apparent during design when special emphasis on the safety of nearby installations and potential threats to population is to be made.

5.4.4.1 Safety Zones

The definitions of Exclusion Zone and Safety Zone are as follows [17]:

Exclusion Zone

Exclusion zone is a 'Keep out' or buffer distance as a part of Risk Management Strategy- prevention and mitigation. This type of approach has been used and is in use by the LNG industry, the Coast Guard, and public safety organizations to ensure the safety and transportation of LNG

Safety Zone

Safety zone is for management approaches to reduce risks to public safety and property from LNG spills. The most significant impacts to public safety and property exist within approximately 500 m of a spill, due to thermal hazards from fires.

Large unignited LNG vapour releases are unlikely. If they do not ignite, vapour clouds could spread over a distance greater than 1600 m from spill.

The following exclusion zone distances may be considered at present as a guideline

Exhibit 5-12 Recommended exclusion zones based on [17]

Exclusion Zone	Distance	Remarks
Navigation Exclusion Zone	**375 m**	From near-side of vessel to shipping channel centreline
Adjacent Jetties (from other cargo jetties)	**500 m**	
Maritime Exclusion Zone	**500m**	-

Due to the limitation of information during Feasibility stage, the distances above shall be further evaluated and quantified more accurately in a Quantitative Risk Assessment (QRA) during FEED stage. It is recommended to carry out a QRA during FEED to authenticate the Maritime Exclusion Zone (MEZ) and Safety Zone (SZ) following a QRA Approach.

5.4.4.2 Safety Procedures

The risk associated with potential collision of the LNG carriers and interferences with the activities of the adjacent terminal at Port Louis has also been considered during the pre-feasibility studies. Over half of the accidents involving gas carriers, such as striking, collisions and grounding have occurred in port approaches and during berthing operations [18].

The proposed location for the LNG terminal is south west of the existing port facility in Port Louis and as such does not seem to create any significant interference with the existing port operations; in addition, the number of shipments per year is likely to be relatively small (approximately 18 unloadings per year) and consequently the LNG tanker traffic will be limited offering a reduced threat of collision.

However given the proximity of the two infrastructures a number of port control procedures are to be implemented to minimise any interferences; these include (but are not limited to):

- Port Control during approach: long and mostly short range aids to navigation (beacon, leading lights, buoys and associated sound signals) will have to be accurately designed and provided, maneuverability limits for visibility, wind current and wave heights will be set together with a speed limit for approaching maneuvers.
- Tugs and escort crafts: to minimize any risk during approach, tugs could be provided farther seaward (beyond the normal assistance area) to assist the entire maneuver as well as escort crafts. Environmental operating limits of the assisting tugs will be identified at further design stage; for the purpose of the pre-feasibility design four standard tugs have been considered to assist the vessel during berthing/unberthing operations.
- Establish a Vessel Traffic Service to monitor and coordinate the movement of all craft within the port and the LNG terminal area.

5.4.5 Berth downtime

Berth downtime analysis is to be undertaken at further design stage. Ship motions and associated mooring and offloading requirements are assessed based on the environmental conditions and correspondingly the level of berth availability for offloading operations is determined.

Berth downtime is not deemed to be critical for the site selection and the design of the marine components on the basis of the following considerations:

- The wave climate off the coast of Port Louis is relatively quiet. Waves and swell from open sea occur only approximately 10% of the time (refer to Section 4.3.2)
- Extreme wave conditions are mainly associated to cyclones. The months of January/February are the most active in terms of cyclones which are very likely to impact the selected site. A cyclone early warning system will be required and following a warning the terminal operations will be immediately suspended.
- The number of unloadings per year is very limited (approx. 18) and correspondingly the target availability is very limited.

5.4.6 Proposed layouts

Sections 3.4.1 to 3.4.3 propose several different alternative schemes for an LNG import terminal. Two different concepts have been considered as basis for the prefeasibility studies: a FSRU and an onshore-based LNG terminal respectively.

The preliminary layout development is described as follows.

5.4.6.1 FSRU

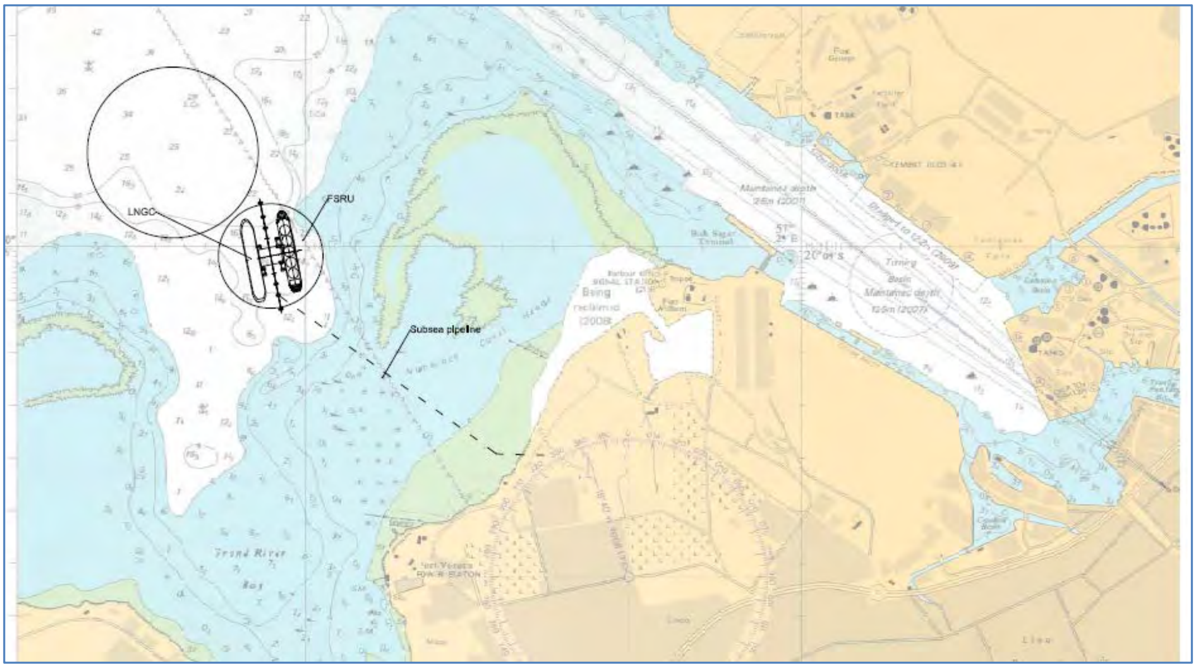
A number of alternative floating LNG technologies have been described in Section 3.4. Section 5.4.3.1 described a number of alternatives mooring systems, however for the purpose of the pre-feasibility design of the marine terminal a dual berth jetty concept is considered, as described in Section 3.4. Exhibit 5-13 shows a conceptual layout for the described FLNG option. The offshore ship berthing and LNG unloading facilities is located in relatively deep water and oriented NW-SE. The subsea gas export pipeline, likely to be installed in a trench excavated on the seabed, runs from the FSRU to the onshore receiving facility.

For the considered sizes of FSRU and LNGC, it is proposed that a berth pocket of approximately 450x250mx14m (LxWxD) and a depth of 16m within the access channel is required. This is available around the 15-20m CD (which is approximately equal to LAT) bathymetry line with no need for any dredging operation. Berth pocket size may require additional space for manoeuvring which will have to be confirmed during navigational simulation.

Given the relatively limited quantities of LNG required, berthing and offloading operations can be precisely planned and carried out during benign weather conditions and therefore it is envisaged that a breakwater will not be required. The platform, the buried pipeline, the associated equipment and topsides will however need to be designed to withstand a severe cyclonic event.

The FSRU is expected to sail away when rough sea conditions (severe storms and/or cyclones) are forecasted. It is assumed that the FSRU will seek shelter in the nearby Port Louis harbour during the storm event.

Exhibit 5-13 FSRU based LNG marine terminal



5.4.6.2 Onshore terminal

A description of the typical configuration of the marine facilities for the shore based LNG import terminal is given in Section 3.4.

Exhibit 5-14 shows two alternative concepts for the land-based LNG terminal concept.

The first option (in red) comprises a long piperack trestle structure and an offshore North-South oriented berthing and offloading platform. This would accommodate a 400x65mx14m (LxWxD) berth without need for any capital dredging (to be confirmed by navigational assessment), but it would require a significantly long trestle and piperack structure (in the order of 1 to 1.5 km) to reach the required bathymetric contour in deep water.

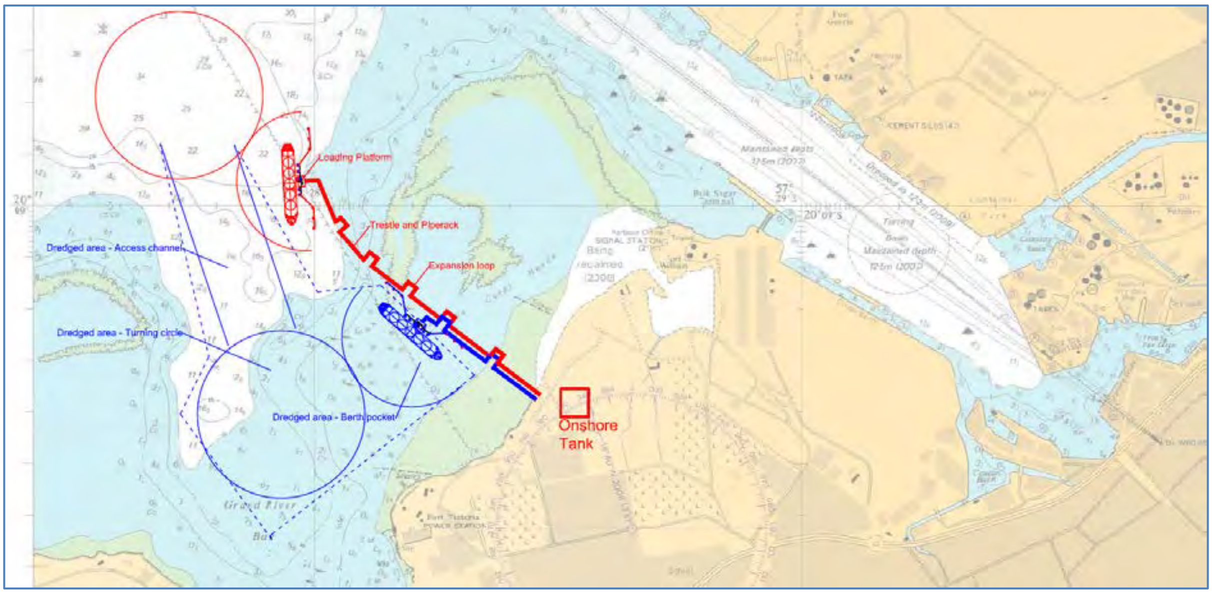
The second alternative (in blue) consists of a nearshore NW-SE oriented offloading platform. This would require a much smaller initial investment in terms of cryogenic pipes, piperack and trestle structure, and a lower requirement in terms of structural sizing. As being the terminal positioned in shallower water depth, the associated design wave climate is likely to be less severe and correspondingly structural elevation and general member sizing will be reduced.

This option however requires a significant amount of dredging which may cause an increment of the overall costs and a more or less severe environmental impact, although given the proximity to the existing port, maintenance dredging operations could be performed by the Port Authority and dredged material may be re-utilised for onshore reclamation works.

Negative environmental impacts associate to dredging activities may be a potential showstopper for this alternative, although dredging activities are currently taking place at the adjacent facility at Port Louis and therefore are not likely to represent a significant issue.

Similar considerations apply as for the FSRU option in terms if breakwater requirements. Given the relatively limited quantities of LNG required It is envisaged that no breakwater will be needed and correspondingly berthing and offloading operations can be planned and carried out during appropriate weather conditions. Fixed structures shall however be designed to withstand an extreme cyclonic event.

Exhibit 5-14 Shore based LNG marine facility



5.4.6.3 Discussion and Recommendations

The site designated, in the vicinity of the existing port terminal at Port Louis, is suitable for the installation and the construction of a marine LNG import terminal. As being located on the west side of the island the shoreline is relatively protected from wind waves from the dominant south-eastern sectors and southerly ocean swells, which ensures a relatively high availability for offloading operations at berth. Cyclonic waves however can occur occasionally and cause significant damage to any coastal infrastructure which will have to be designed accordingly.

Two alternative concepts have been presented for the marine infrastructure, a floating option with a dual berth jetty and a shore based LNG terminal connected to an offshore platform by means of a steel trestle.

No detailed analysis on berth availability has been undertaken at this stage; nevertheless it is unlikely that a breakwater will be required considering the limited number of unloadings required per year.

Berth access will be planned in advance on the basis of adequate weather conditions and cyclone early warning systems will be adopted to prevent major accidents during terminal operations.

The floating option is initially positioned relatively far from the shore to minimise dredging activities and any related environmental impacts, whilst two optional configurations are considered for the shore based option: an offshore loading berth option connected to shore with a long steel trestle and a near-shore option which requires substantial dredging volumes.

A preliminary assessment of Capex ,Opex and schedule associated to these options is given in the following section.

A number of additional studies will be required at further design stage to finalise the design of the marine facilities; these include (but are not limited to):

- Detailed Metocean modelling
- Detailed coastal studies
- Site investigations including topographical, bathymetric, geophysical and geotechnical surveys
- Assessment of geohazards and tsunamis
- Assessment of hydrological and hydrogeological risks
- Navigational assessment

5.5 LNG Import Infrastructure cost and schedule

LNG Import Terminals are cost intensive. Since LNG is stored at Cryogenic temperatures, the materials of construction are 9% Ni Steel for tanks stainless steel for piping and valves. Additionally thick cryogenic insulation is required to minimize heat ingress to minimize boil-off.

The basis and the assumptions for the Marine terminal cost estimate are discussed in the following paragraphs.

5.5.1 CAPEX

The CAPEX represents the total capital expense required to design, fabricate, transport to, then install and commission the LNG terminal.

FSRU

Majority of the CAPEX is for Piling, Jetty, Marine Loading Arms and other LNG recovery equipment, piping on jetty, Sub-sea pipeline and Onshore Receiving Facility with ESD, pressure let down, HIPPS and Metering

Onshore Terminal

Majority of the CAPEX is for LNG Storage Tank, Piling, Jetty, Marine Loading Arms, cryogenic piping on trestle, LNG Regasification equipment, piping, pressure let down, HIPPS and Metering.

An *absolute* CAPEX has been developed for the marine components of the LNG terminal for option 1 (Floating) and option 2 (Shore based) respectively.

The CAPEX for the marine and on-shore components of the LNG terminal has been developed based on cost build-up of the major components, which include:

- Fabrication of the steel component and installation of trestle, piperack and loading platform:
- Onshore Storage and Regasification plant
- LNG loading mechanism and topsides.
- Subsea pipelines.
- Dredging activities

CAPEX costs associated with design and commissioning will be included for this stage based on typical oil and gas industry norms. The CAPEX provided also includes installation cost.

The CAPEX components has been developed based on WorleyParsons global-internal cost database built-up from previous projects and adjusted to present value.

5.5.2 OPEX

The OPEX includes the cost associated to the operation and maintenance of the LNG facility. This includes:

- Lease (for Floating LNG option):
  - For the exercise of the pre-feasibility study, it is assumed that the FSRU is to be leased[17] (including the LNG containment system) and the remaining SRT components are to be procured.
- Utilities and Services
  - Electric Power Consumption for Sea Water Pump, BOG Compressor, LNG Booster Pump;
  - The Electric power consumption varies based on capacity utilization of LNG Terminal. Estimate for 0.3 MTPA and 1 MTPA Regasification capacity are provided in Exhibit 5-16.
- Tugs operations and Crew requirements:
  - As a minimum, operations crew is required for all concepts. For some concepts, a marine crew is also needed to maintain the marine/mooring structures..
  - Tugs are assumed to come from the existing port to perform towage assistance during approach, berthing and offloading operations.
- Maintenance dredging: as discussed in Section 5.5.3.2

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[17] The chartering of an FSRU is standard industry (vs. owning it) practice and the costs are being reflected as OPEX in the financial model i.e. being taken into account for the lifecycle cost analysis. Indicative CAPEX costs for ownership is given below for interest:

- New Built FSRU 170,000 m^3 total cost = USD 276 million
  - Total cost inclusive of Vessel Cost, Regas Skid, LNG loading equipment, Vent system, Cryogenic System, Boil off Gas system, Power Generation, Mooring System
- Converted FSRU 150,000 m^3 total cost = USD 246 million
  - Total cost inclusive of Vessel Cost, Refurbishment, Regas Skid, LNG loading equipment, Vent system, Cryogenic System, Boil off Gas system, Power Generation, Mooring System

- General operational maintenance & spares

5.5.3 Assumptions

5.5.3.1 Accuracy

Costs are estimated to be accurate to within 50%.

5.5.3.2 Dredging

Depending on the concept selected for the shore based option, dredging may be required. Minimum dredged depths are assumed to be as follows:

- Loading platform berth -14.0mLAT
- Approach channel -16.0mLAT

For the purpose of the pre-feasibility study an initial assessment of dredging methodology has been based on a review of available information; namely a number of borehole drillings carried out for the cruise berth terminal and a study recently undertaken on the extension and strengthening of the Mauritius Container Terminal (MCT) located at Mer Rouge, Port Louis.

Dredging activities will have to be carried out in shallow water, with the dredging operating in the presence of swell dominated sea (although the site is relatively sheltered from dominant southern swell direction) and the possibility of severe cyclones to occur. Material to be dredged includes soft to firm clay, silt, very loose to loose sand but can also consist of harder material such as limestone and basalt. Given the high variability of the material that can be encountered a Cutter Suction Dredger is likely to be required. The dredged material can then be piped directly to the shore and re-utilised for any reclamation works associated to the construction of the on shore receiving facility.

Depending on the final location of the terminal capital dredging may be required. An initial assessment of dredging volumes has been set to the order of 1 to 5 million of m^3.

Maintenance dredging will also be required and will form part of the OPEX estimate. Annual maintenance dredging is preliminarily assessed as 15% of capital dredging volumes.

5.5.3.3 Trestle and Loading Platform

A steel piled structure will be used as berthing and loading platform for the LNGC; at this stage it is envisaged that this will be a dual-berth type structure for the Floating LNG and a single berth connected to shore by means of a steel trestle (also supported on steel piles) for the shore based option.

Piles will be driven to the underlying weathered basalt layer to provide sufficient bearing capacity and minimise any differential settlements. Structural elevation will have to be set above maximum crest elevation in order to avoid any slamming load underneath platform deck, specialist wave studies will be required in further design stage to identify final structural configuration, this is likely to be driven by extreme cyclone events and related phenomena (surge, high speed winds and large wave heights).

5.5.4 Cost Summary

A preliminary cost evaluation for both, floating and shore based terminal option is given as follows:

Exhibit 5-15 CAPEX estimation

Item	Description	CAPEX - MARINE TERMINAL - FSRU		CAPEX - MARINE TERMINAL - Shore based	
		Note	Cost [m$]	Note	Cost [m$]
1	Preliminary activities				
1.1	Design and Procurement activity		approx 15		approx 5
1.2	Site Investigations		approx 10		approx 2.5
1.3	Permits and Approvals		approx 5		approx 2.5
2	Construction and Installation				
2.1	Berth and Loading platform		75 to 125		approx 25
2.2	Dredging		n/a	May/may not be required depending on selected concept	0 to 50
2.3	Trestle (including piperack and topsides)		n/a	Length depending on concept	200 to 350
2.4	Pipeline		15 to 30		n/a
3	Onshore Facility				
3.1	Storage and regasification		n/a		150 to 250
3.2	Receiving facility		15 to 30		25 to 50
4	**Total CAPEX**		**180**		**575**

Exhibit 5-16: Estimated Electric Power Consumption

Item	0.3 MTPA LNG Regas	1.0 MTPA LNG Regas
	Estimated Electrical Power Consumption, kw	
Electrical consumption for FSRU accommodation, utilities and others	2500	2500
Electrical consumption for Sea Water Pump	400	1000
Electrical consumption for LNG Booster Pump	300	700
Average Electrical consumption for BOG Compressor	800	800
TOTAL, Power Consumption	4000	5000

Exhibit 5-17 OPEX estimation

Description	OPEX-Marine Terminal - FSRU		OPEX Marine Terminal Shore Based	
	Note	Cost [mmUS$/annum]	Note	Cost [mmUS$/annum]
Fixed Items				
FSRU Leasing Cost	178k $ 158.9k/day	58.00	N.A.	0.0
Crew Cost Jetty	3 teams employed (2 membered)	0.30	3 teams employed (2 membered)	0.30
Crew Cost Onshore ORF	3 teams employed (2 membered)	0.30	N.A.	0.0
Crew Cost Onshore Option	N.A.	0.0	6 teams employed (5 membered)	0.48
Dredging Maintenance Cost	Assumes no maintenance dredging	0.0	Assumes 15% of capital dredging.	5.75
Project Management + Insurance	1% of CAPEX	1.78	1% of CAPEX	5.75
Sub-TOTAL FIXED O & M		60.38		11.93
Variable Items				
Maint. & Spares-Jetty top side	Based on 3 % of Total Equipment Cost on Jetty	0.20	Based on 3 % of Total Equipment Cost on Jetty	0.99
Maint. & Spares-Moorings	Based on 3 % of Total Equipment Cost on Jetty	incl. above	Based on 3 % of Total Equipment Cost on Jetty	incl. above
Maint. & Spares-sub-seaPipeline	Based on 1 % of Supply Cost	0.11	N.A.	0.0
Maintenance & spares- Trestle and Cryogenic	N.A.	0.00	Based on 1 % of Supply Cost	0.43

Description	OPEX-Marine Terminal - FSRU		OPEX Marine Terminal Shore Based	
	Note	Cost [mmUS$/annum]	Note	Cost [mmUS$/annum]
Pipelines				
Maintenance & spares- ORF	Based on 3 % of Supply Cost	1.50	N.A.	0.00
Crew Cost for FSRU+ maintenance spares expenses	@ 22,000 USD/day	8.03	N.A.	0.00
Maintenance & spares- Onshore	N.A.	0.00	Based on 3 % of Supply Cost	8.58
Tugs- LNG Transfer	25,000 USD /service (includes 4 Tugs & Pilot) - assumes 30 services	0.75	25,000 USD /service (includes 4 Tugs & Pilot) - assumes 30 services	0.75
Electricity Utilities Operating Cost: FSRU, Jetty+0RF/OSRT (Note-1)	Electricity Consumption on FSRU:4 MW, Diesel Consumption 0.184 kg/kw, Diesel 750US$/ton	4.80	Electricity unit cost 0.22 USD/KWH	5.78
Sub-TOTAL Variable O & M		15.39		16.53
Total O&M		**75.77**		**28.46**

5.5.5 LNG Import Infrastructure Construction Schedule

Indicative project durations for the design, procurement and installation of the marine components for the floating and the shore based LNG terminal options are based on the following activities:

- FSRU
    - Preliminary design and issue of EPC tender: 16 to 19 months
    - Site investigations Meteocean, geotechnical, geophysical: 10 to 12 months
    - Permitting requirements (EIA, local authorities, permits and approvals): 10 to 12 months
    - Detailed Design and construction (Jetty, Pipeline and ORF): 18 to 24 months
- Shore based terminal

- Preliminary design and issue of EPC tender: 16 to 19 months
- Site investigations (Meteocean, geotechnical, geophysical): 10 to 12 months
- Permitting requirements: 10 to 12 months
- Detailed Design and construction (Storage Tank, Regas facility, Jetty, Piperack and trestle): 32 to 36 months

Activities i) ii) and iii) above can progress in parallel and have similar duration for both floating and shore based option. Conversely Activity iv), which includes procurement and construction of the marine facilities, has a substantial longer duration for the shore based option.

For the floating option, the construction of the offshore dual berth type jetty and the subsea pipeline will occur in parallel with the award of the FSRU contact and the delivery to site. Both activities are deemed to have similar duration.

For the shore based option, the construction of the marine facility will progress in parallel with the installation of the storage and regasification onshore terminal, however it is likely that the construction of the LNG Storage Tank will have longer duration and will lie on the critical path of the overall construction schedule. For this option any delay associated with the general progress of LNG Storage Tank would affect the overall duration of the construction schedule and in turn affect the implementation plan.

5.5.6 Discussion: FSRU vs Onshore

A class 1 cost estimate (confidence range < + 50 %) has been prepared based on WorleyParsons past project experience and database on similar projects, no budgetary quotations were sought from vendors specific to this project.

Capex and Opex estimates have been provided for two options: a FSRU and a shore based LNG terminal, together with a general description of the associated technology. The floating LNG option requires a smaller initial investment and has a relatively low capital cost, whilst the corresponding operational and maintenance cost is relatively high. Conversely the shore based option requires a significant initial investment that can be as high as 3 times the cost required for the floating option, but a smaller operational cost which is approximately 3 times lower than the FSRU.

Also in terms of schedule the two options differ quite significantly: the floating option is based on the conversion of an existing LNG carrier into a FSRU unit which is then transported to site; while the shore based option will have to be entirely installed on site and will therefore require a longer construction schedule, which combined with the higher capital costs cost may make it less attractive.

The shore based terminal on the other hand, may offer higher berth availability and lesser risk of cyclone induced disruption and/or structural damage; however given the relatively low number of LNG shipments per year and the highly effective cyclone warning system in place at Port Louis, there is a very low risk that a floating option will not achieve the desired target performance.

The final determination of when/if the FSRU is to be disconnected and the location and appropriate type of mooring can only be undertaken once the magnitudes of wave, wind and current forces associated with the occurrence of cyclones and heavy storms have been assessed. This requires:

- Detailed bathymetric survey information
- Met-ocean studies to determine operational and extreme characteristics of waves, hydrodynamics and winds
- Mooring and navigation analyses
- Uptime assessment

These studies are generally carried out during pre-FEED/FEED stages.

On this basis, for the purpose of the pre-feasibility preliminary options appraisal, an FSRU option will be considered forward and adopted as basis for the economic and financial modelling.

These considerations are summarised in Exhibit 5-18

Exhibit 5-18 High level options appraisal

	FSRU (dual berth type jetty)	**Shore based terminal**
CAPEX	Reduced initial investment	High initial investment
OPEX	High operational and maintenance costs	Reduced operational/maintenance costs
Schedule	Award of FSRU contract and construction of marine facilities will occur in parallel. Estimated construction schedule in the order of 24 months.	Driven by construction of the LNG Storage Tank. Overall construction duration may exceed three years.
Performance (Terminal availability)	Higher susceptibility to weather downtime.	Higher berth uptime and correspondingly high operational performance.
Safety	Offloading in potentially harsher environment. Need for cyclone warning system.	Need for cyclone warning system.

5.6 Conclusions and Recommendations

Technically it is feasible to build a FSRU based LNG Import Terminal in Mauritius with a Regas capacity of 1 MTPA to operate initially at 0.3 MTPA capacity and to ramp up to 1 MTPA looking for potential for growth and opportunities for industrialization. However, it is commercially challenging to recommend a LNG import Terminal at present due to: a) Low demand and b) supply sources of LNG. It is recommended that the LNG demand in Mauritius and the region be watched carefully and when the economic viability of the Terminal becomes more convincing, justifiable and robust, a detailed Feasibility Study is undertaken including the Market Study.

Mauritius may take steps to conduct a market study how the demand for LNG could be raised. Maybe if Mauritius worked with Reunion to also put in LNG facilities, then Mauritius could become a hub and Reunion a spoke, they could possibly have enough LNG to share the 1 MTPA capacity in the future. Another prospect for LNG Regas requirement potential increase may be if industrialization takes place in future specifically of Refining and Petrochemical sector.

In view of above it is suggested that when carrying out the future feasibility studies, the basic infrastructure for LNG is kept at least at 1MTPA. The LNG on the FSRU may be regasified according to the demand and increased as the demand grows.

6. LNG SUPPLY CHAIN

6.1 Introduction

In addition to the important technical considerations for importing LNG and building or converting power plants to burn natural gas, it is important to establish some context about the LNG market and the commercial consideration related to procuring LNG.

The LNG market is quite different from the crude oil market because it is not yet a true commodity. While the crude oil market is very large, flexible, and consist a worldwide trading market on a short-term transactional basis, the LNG market is about one tenth of the size of the crude oil market and consists mostly of long-term transaction. Exhibit 6-1 compares and contrasts some key factors about the crude oil and LNG markets that help demonstrate why LNG is not a true commodity.

Exhibit 6-1: Comparison of Crude Oil and LNG Markets

	Crude Oil	LNG
2010 Shipments	53 million barrels/day	225 million tons/year (5.3 million BOE/day)
Exporting Countries	79	19
Importing Countries	98	24
Number of Ships	4,300	355

The scale of the crude market (volume, number of participants, seamless and ubiquitous logistics) enables much more liquidity and pricing transparency in the market whereas LNG is still, relatively speaking, a small market with relatively few participants and significant logistical constraints. Long-term negotiated contracts in the LNG market reduce pricing transparency and limit overall market flexibility (although increasing market flexibility will be discussed later in this chapter). The capital intensive nature of LNG projects requires long-term sales commitment from creditworthy buyers to support the financing of such massive capital investments. For reference, it is typical for an LNG export project to require two to four times more capital than a similarly sized oil export project.

The goal of this chapter is to provide some context about LNG markets by presenting an overview of LNG markets and pricing dynamics, identifying potential supply sources and suppliers, and addressing the issue of developing sufficient scale to absorb the relatively high capital costs required to develop the LNG import and distribution infrastructure in Mauritius.

6.2 LNG Global Market Overview

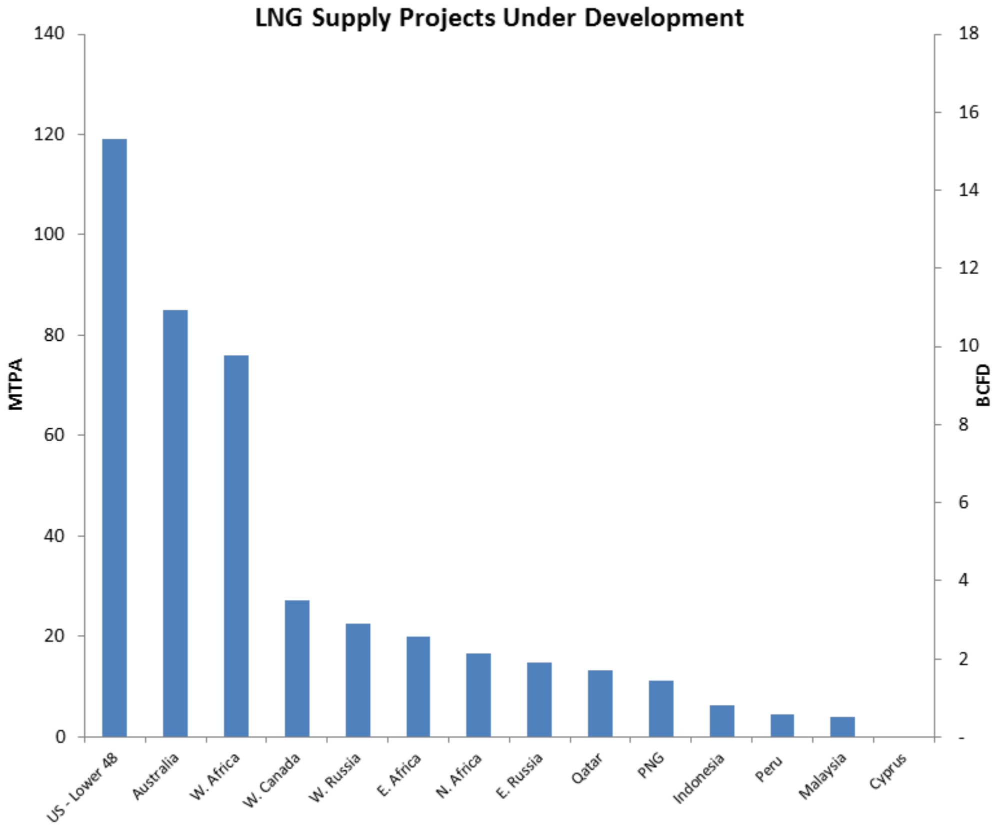
6.2.1 Overview of the LNG Supply Landscape

The LNG industry has experienced significant growth over the past 10-15 years, both in terms of demand as well as supply capacity. In 1995, only 11 LNG projects were operational. By 2012 there were 35 liquefaction projects in operations globally, as depicted in Exhibit 6-2. The combined capacity of existing LNG liquefaction projects is approximately 256 MTPA. Approximately one half of the global LNG supply capacity is in Qatar, Australia and Malaysia.

Exhibit 6-2: Global LNG Liquefaction Projects, 2012(to be update for YE 2013) [30]

Moving forward, significant additions of new liquefaction capacity are expected to meet growing demand for natural gas globally. By 2020, the number of exporting countries is expected to increase slightly from 19 to over 22. Sources of LNG supply are expected to become more diverse with the addition Eastern Australia and North America to complement existing supply sources from the traditional LNG exporting regions in North Africa, West Africa, South East Asia, Western Australia, Russia, South America, and the Middle East. The largest LNG producers are expected to be Qatar, Australia and North America. Beyond 2020, new projects in East Africa, the Mediterranean, and Russia's Artic are expected to provide further additions to the global supply of LNG. However, although the inventory of LNG projects is sizable, these projects are in various stages of development. Consequently, there is significant uncertainty as to which projects will materialize as well as to when they would come online because of many potential challenges such as increasing capital costs, limits on the industry's capacity to engineer, finance and construct such large projects, host country policies and stability, and demand for LNG. If completed according to their publicized schedules, these projects would add over 370 MTPA to the global LNG supply capacity, as seen in Exhibit 6-3.

Exhibit 6-3: LNG Liquefaction Projects Under Development [31]



6.2.2 LNG Suppliers

LNG supply projects have traditionally involved international oil and gas companies (IOCs) such as Shell, BP, BG, Chevron, Total, ExxonMobil, etc. National oil and gas companies (NOCs) such as Pertamina, Sonatrach, Statoil, Petronas, Qatar Petroleum usually partnered with IOC's to develop the LNG projects (including the upstream oil and gas reserves), and share the risks and the capital expenditure requirements. These "partnerships" have taken the form of formal Joint Venture Companies (JV), production sharing contracts with technical services, or combinations. Prominent LNG JVs include Nigeria LNG, RasGas, Qatargas, Angola LNG, Sakhalin, etc. The LNG can both be marketed, and sold through the JV company (usually with the assistance of the major IOC shareholders), or by each shareholder individually (usually through the shareholder's marketing or trading affiliate). Because of the very high capital requirements for new LNG projects, including major expansions, LNG sellers have tended to seek long-term contracts (15 to 20 years) with buyers that could provide strong credit backing. These long-term contracts are required to support project financing as well as provide the stability sought by the IOC's and NOC's to invest the significant amount of equity capital. Although LNG suppliers may seek to allocate the majority share of the LNG output from a project to direct long-term contracts, many of these companies elect to retain a portion of the volumes to be included in their LNG supply portfolio which they can market and trade independently. The term "Portfolio Supplier" refers to those IOCs and NOCs that have elected to build internal portfolios of LNG supplies which they control independently of their project partners. These portfolio supplies can be available under much more flexible conditions than the long-term supplies depending on each Portfolio Supplier's approach to the market and portfolio optimization strategies. For example, some Portfolio Suppliers may be amenable to selling LNG for shorter-terms (less than five years), while others would prefer to only commit LNG supplies on a longer-term basis (greater than ten or fifteen years). Pricing preferences and outlook of future market balance will also vary from supplier to supplier.

In addition to IOCs and NOCs, some of the major LNG buyers, such as Kogas, Osaka Gas, Tokyo Gas, Tokyo Electric, Gas de France (now GDFSuez), and Gas Natural Fenosa have opted to become involved in LNG projects, usually as minority equity stakeholders. Although, the typical motives for such involvement are transparency and increased offtake flexibility, some of these LNG buyers have elected to actively market and trade a portion of their supply portfolio, usually with the goal of leveraging LNG supplies in downstream market activities such as power generation, natural gas sales, etc.

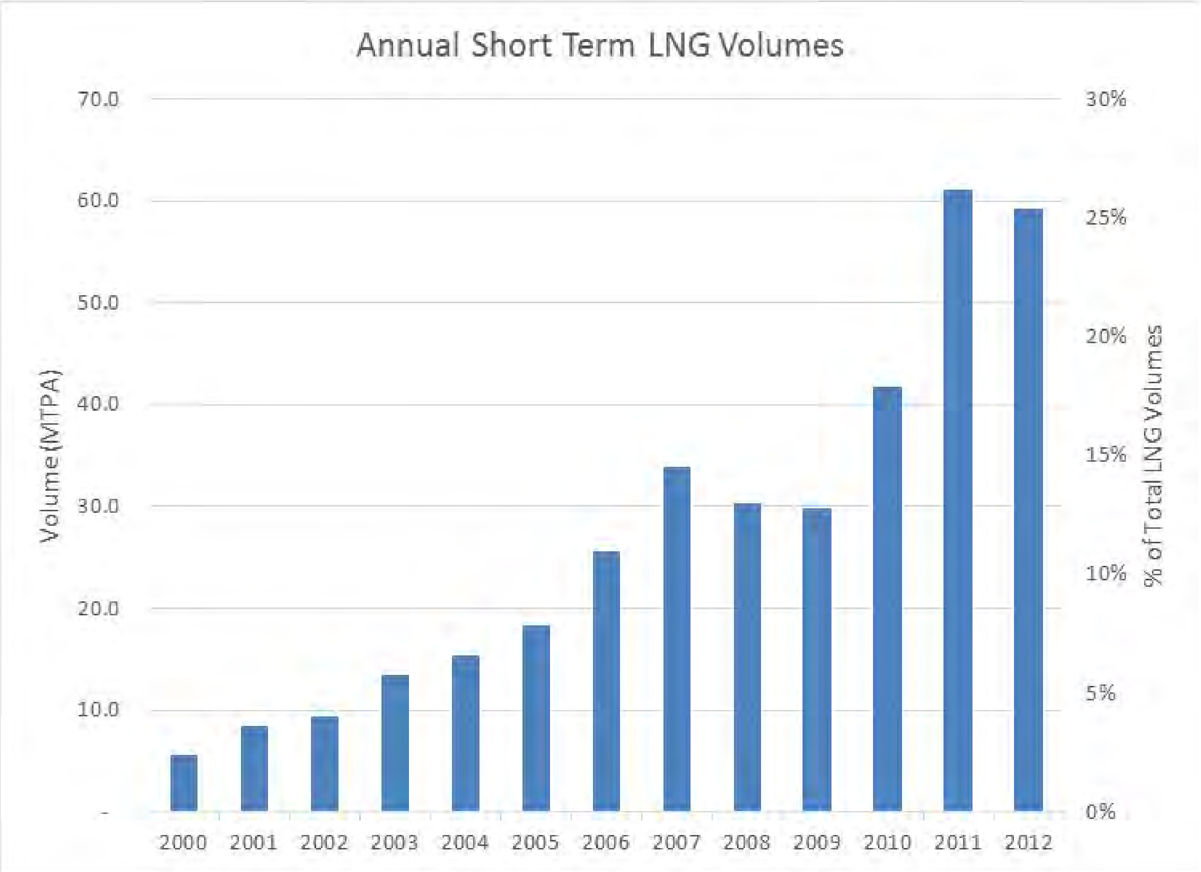
The third type of potential LNG suppliers includes a relatively broad category of commodity traders. Japanese "trading houses", such as Mitsui and Mitsubishi, have been engaged in LNG demand aggregation and management on behalf of Japanese gas and power utilities for decades, often acting as agents for their customers in Japan. Over time, the Japanese trading house have participated in the market independently of their Japanese customers as they expanded their activities globally. Several of these companies have contracted for long-term LNG supplies and are marketing a portion of the portfolio to international third parties, usually with the goal of promoting additional activities and investments downstream. In addition to the Japanese trading houses, commodity-trading companies are increasingly engaged in aggregating and reselling LNG primarily in short-term transactions (individual cargoes, multiple cargoes over relatively short periods of time). These "LNG Traders" include Vitol, Citi, JP Morgan, Morgan Stanley, Trafigura, Gunvor, Macquarie, among others.

6.2.3 Overview of the LNG Demand Landscape

LNG is imported in countries that either do not have domestic natural gas resources or insufficient and no access to natural gas imports via pipeline, such as Japan and South Korea, or countries that have insufficient domestic natural gas production and or limited or insufficient access to natural gas imports via pipeline, such as China, India, United Kingdom, etc. Originally, LNG buyers tended to be natural gas or power utilities and purchased LNG to resell gas or power to end-users. Over time, some end-users started to purchase LNG directly for large scale applications such as large CCGT power generation or industrial use (such as petrochemical and refining). Between 1995 and 2013, global regasification capacity expanded from 178 MTPA to 527 MTPA, and the number of countries with import and regasification facilities grew from 8 to 29 during the same period. In 2013, the United States had the largest amount of importing and regasification capacity with the ability to import 126 MTPA. Yet, LNG imports into the US were only about 2 MTPA because most of the LNG import and regasification sat idle due to the significant increase in domestic natural gas production. In many countries, it is not unusual to have excess regasification and import capacity usually to manage seasonal demand fluctuations. Consequently, there is more LNG import and regasification capacity than there is LNG production capacity. LNG volumes bought grew from 103 MTPA in 2000 to 247 MTPA in 2012 (7.5% compound annual growth rate). In 2012, approximately 70% of the 247 MTPA of LNG traded globally were bought by Asian importers. Japan and South Korea are the world's largest LNG consumers with about 128 MTPA (Japan ~90 MTPA and South Korea ~38 MTPA).

As was mentioned in the Overview of the LNG Supply Landscape section above, historically the vast majority of LNG volumes were bought and sold on a long-term basis (15 to 20 years) to support the construction and financing of the supply projects as well as provide security of supply to the buyers. Over time, increasing portions of global of LNG volumes have been traded on a short-term basis (terms of less than 4 years). The portion of LNG volumes traded on a short-term basis has increased from approximately 5 MTPA (~5% of total volumes) in 2000 to approximately 60 MTPA (~25% of total volumes) in 2012. This twelvefold increase in short-term volumes has increased market flexibility significantly. Exhibit 6-4 illustrates the growth of LNG volumes in shorter term trades.

Exhibit 6-4: Historical Short-Term Volumes – Annual Volume and % of the Total Market [32]



The 2011 nuclear disaster in Japan is a perfect example of how the increased short-term flexibility benefited Japanese power generators. After the shut-down of almost all of Japan's nuclear reactors following the 2011 tsunami (~60 GW), Japanese buyers were able to significantly ramp up LNG purchases to fuel thermal power plants and make-up for most of the lost generation capacity.

6.2.4 Overview of Pacific Basin Supply/Demand Dynamics

Rapid demand growth is expected to continue in Asia as Asian economies continue to "gasify". The majority of the demand growth for natural gas is driven by increasing power demand. Rapid natural gas demand growth is expected in China, India and Southeast Asia as those economies continue to grow. Because domestic supplies of natural gas are not expected to be able to keep pace with demand growth, LNG is expected to increasingly make-up the difference and consequently demand in the Pacific Basin is expected to grow to approximately 280 MTPA by 2025. This scenario assumes a recovery of the nuclear power generation sector in Japan. Consequently, the policy of the Japanese government regarding nuclear power generation could cause incremental demand. Both greenfield and expansion projects are being actively developed to keep pace with regional demand growth. As a result, Australia is widely expected to become the largest producer of LNG by 2020, with LNG production approximating 80–90 MTPA. In Canada, several LNG projects in British Columbia are being developed to serve potential Asia buyers.

East Africa could also become a new large potential source of LNG for the Pacific Basin. Over the past few years, significant offshore gas reserves have been discovered in Mozambique and Tanzania. LNG export projects are in various stages of development in East Africa but are facing some initial hurdles with government relations with regards to establishing regulations that promote the massive investments required to develop the natural gas reserves while exporting LNG to credit worthy buyers in Asia (to support financing). Therefore, the timing for these projects is very uncertain.

In addition to projects in the Pacific Basin, a significant amount the production capacity in Qatar, approximately 30 MTPA, can be viewed as commercially flexible. Although those volumes are currently sold to JV shareholders for deliveries to the US and Europe, these volumes can be diverted to more attractive markets under the right commercial conditions. Consequently, the Pacific Basin is expected to remain well balanced from a supply and demand perspective. However, new greenfield projects will need to be sanctioned over the next few years in order to satisfy demand. Exhibit 6-5 below shows existing and proposed supply projects in the Pacific Basin and Exhibit 6-6 below illustrates project supply and demand dynamics in the Pacific Basin.

Exhibit 6-5: Pacific Basin LNG Liquefaction Projects [30]

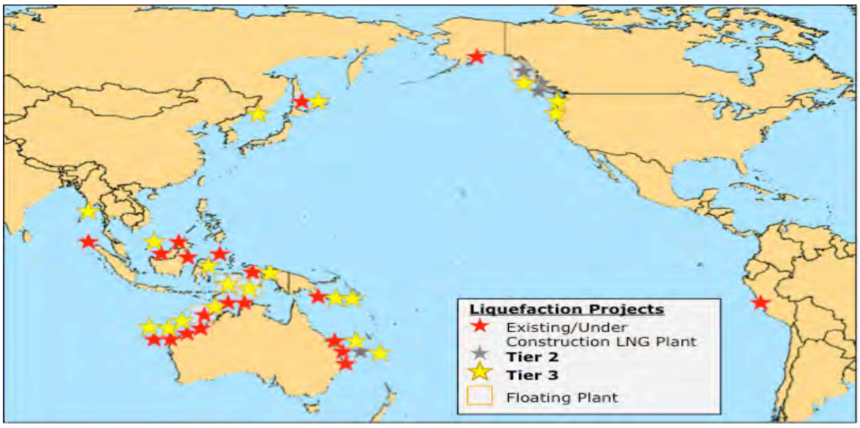
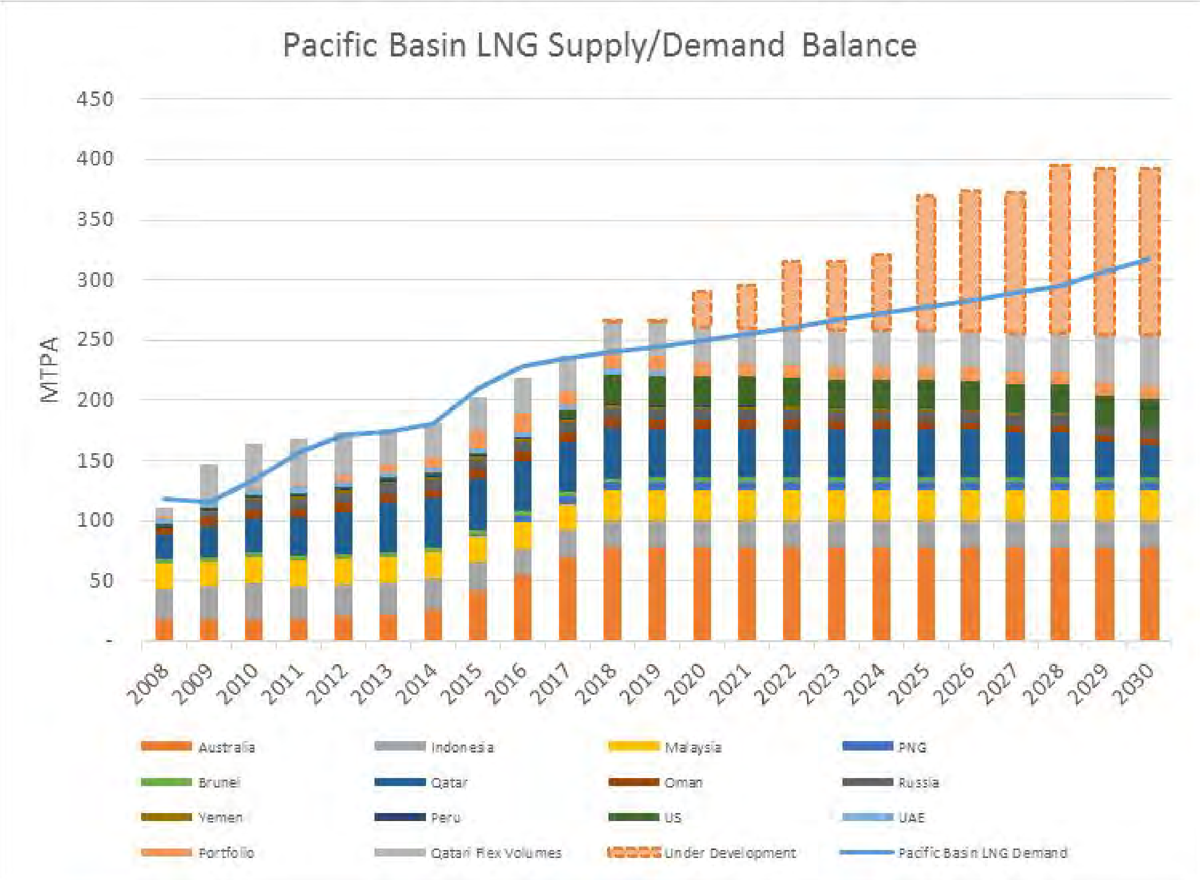


Exhibit 6-6: Pacific Basin LNG Supply/Demand Balance [33]

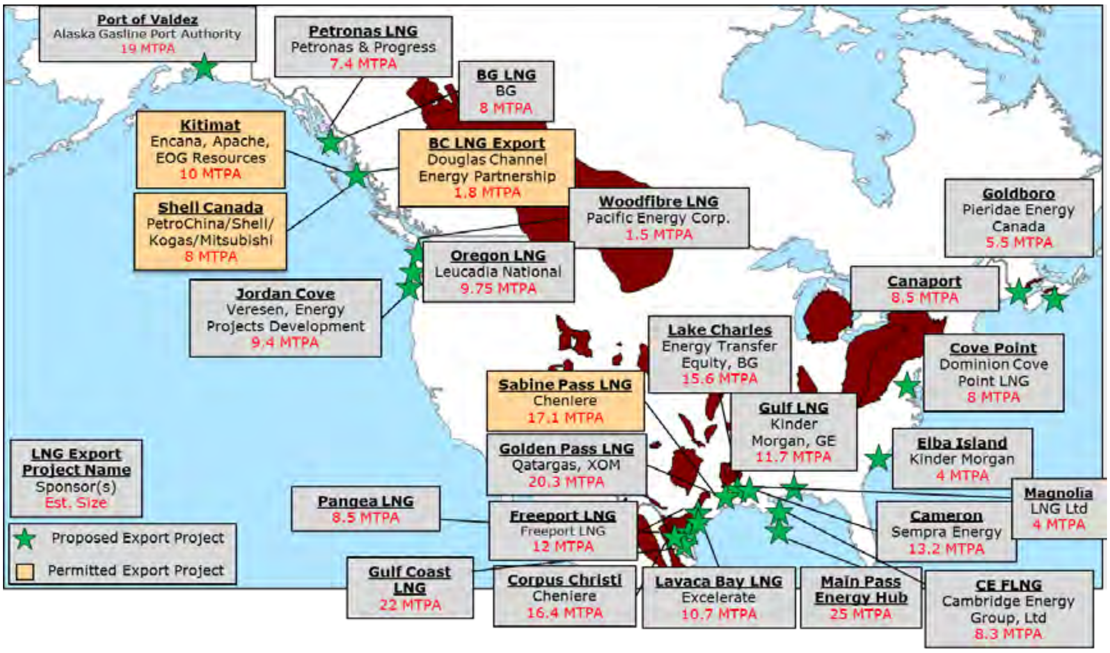


6.2.5 Overview of Atlantic Basin Supply/Demand Dynamics

In the Atlantic Basin, LNG supplies are more flexible compared to the Pacific Basin because many markets can be characterized by LNG-on-gas competition in mature natural gas markets. LNG demand growth is relatively moderate in this region, making it a less competitive market environment compared to Asia Pacific. In Europe, gas markets have undergone fundamental changes resulting from the EU's efforts to deregulate gas markets and promote more competition. As a result of these efforts, volumes of natural gas bought and sold in growing spot markets are projected to soon surpass volumes of natural gas bought and sold under long-term oil-linked contracts. Under these emerging natural gas markets, Europe offers an increasingly flexible and liquid alternative market for LNG suppliers. Demand for natural gas in Europe is expected to remain relatively flat due to relatively low economic growth and energy conservation policies. Demand for LNG is primarily driven by lower domestic natural gas production and uncertainty of future volumes (and prices) for gas imported via pipeline from Russia's Gazprom. EU policies have favoured efforts to diversify supply sources and LNG is viewed as one of these diversification methods. In Latin American, demand for LNG is still relatively immature. Demand in Brazil, the continent's largest economy, is driven by seasonal demand (driven by seasonality of hydro power generation). Future demand is uncertain because Brazil has the potential to produce large, technically complex, offshore hydrocarbon reserves. Countries like Argentina and Chile are importing LNG to make-up for natural gas supply shortfalls and demand is generally expected to grow.

In North America, shale production has revolutionized the natural gas market and has opened up the possibility for LNG exports. Shale basins have been discovered throughout the U.S. and Canada, each with a unique mix of dry gas, condensates, and oil. In the U.S., excess shale gas production has driven gas prices to record lows, with Henry Hub prices staying in the range of $3 to $4 over the past couple of years. Exhibit 6-7 illustrates proposed North American projects and projects which are under construction. As recently as the mid 2000's, North America was expected to become a very large importer of LNG. Shale gas development however has completely changed future projections and LNG exports are now widely expected from the US and Canada.

Exhibit 6-7: North American LNG Projects [34]



In addition to potential supplies from North America, there are large natural gas reserves in West Africa that could drive both project expansions in Nigeria, Equatorial Guinea and Angola as well as greenfield projects in Nigeria. However, these projects have faced delays because of political tensions and turmoil and they are not expected to proceed until domestic instability is resolved.

As Exhibit 6-9 below demonstrates, Atlantic Basin LNG demand is expected to grow to approximately 100 MTPA by 2025. Supply and demand should remain well balanced, although new projects will need to be sanctioned shortly to address potential supply/demand gaps by the end of the decade.

Exhibit 6-8: Atlantic Basin LNG Liquefaction Projects [30]

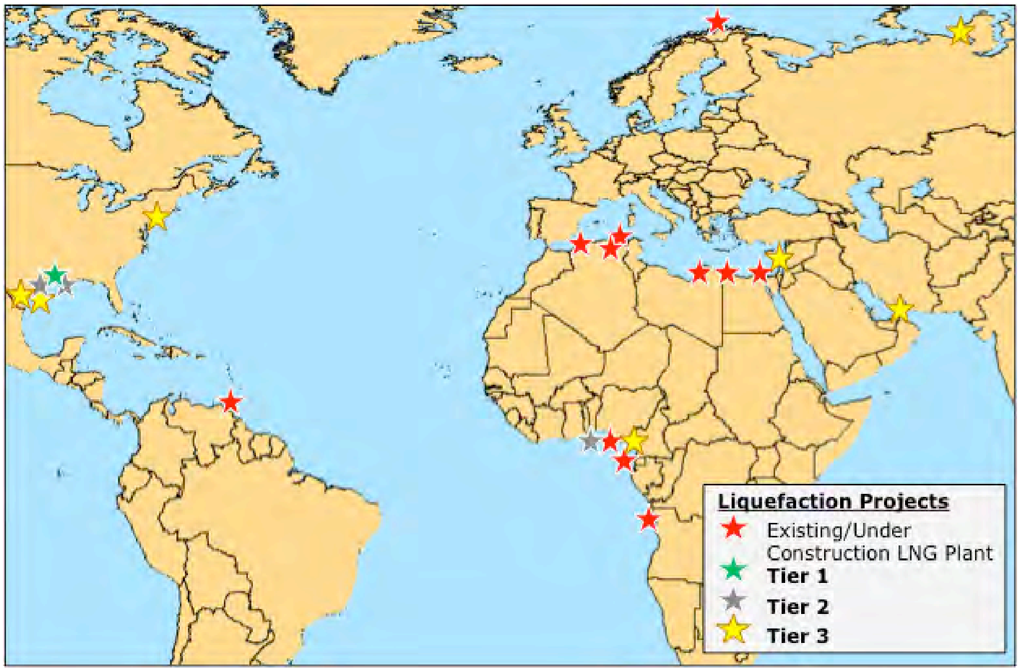
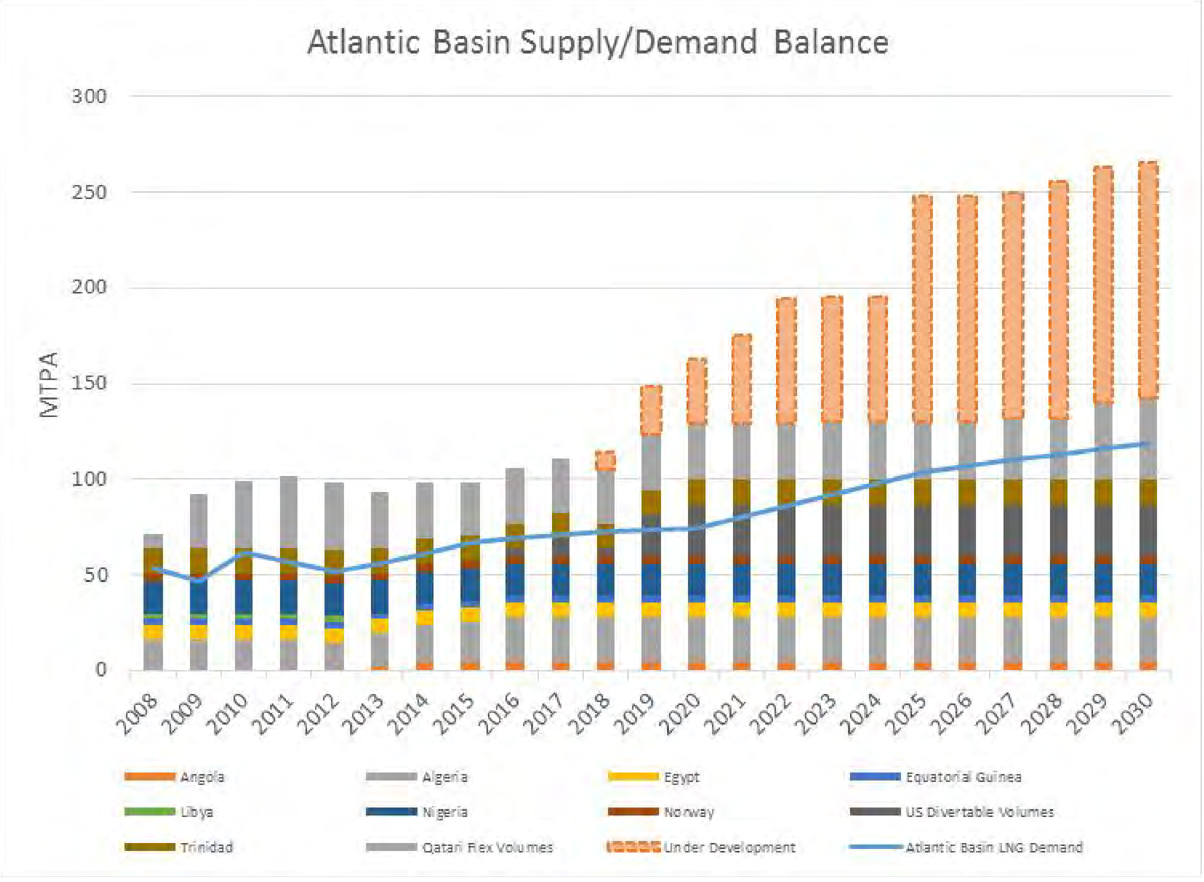


Exhibit 6-9: Atlantic Basin LNG Supply/Demand Dynamics [33]



6.2.6 Evolution of Market Flexibility

As discussed above, the vast majority of LNG volumes were historically sold under long-term contracts (fifteen to twenty years) directly to end-users of natural gas such as electric and gas utilities. As gas markets evolved in North America and Europe to become increasingly liquid, with transparent pricing, and with short-term contractual arrangements, the traditional buyers of LNG tended to shy away from entering into long-term LNG supply contracts. In addition, the IOC's that typically sponsor LNG liquefaction projects became increasingly active in the gas markets in North America and Europe and consequently, their LNG marketing affiliates became the primary off-takers from greenfield projects and expansions. Consequently, LNG supplies in the Atlantic Basin became increasingly flexible and could be diverted to the market of highest value on a short or medium term basis, or committed to long-term contracts.

The consequence of this increased market flexibility is that it is generally accepted that the risk of supply availability is relatively low (low volume risk), but that pricing reflects supply and demand balance for short-term volumes and therefore price risk can be relatively high in times of high demand. This dynamic was confirmed following the Fukushima disaster in Japan in 2011. Following the shut-down of the entire nuclear power fleet, Japanese utilities were able to source relatively quickly approximately 8 MTPA of incremental LNG supplies to fuel previously idled thermal generation plants at relatively higher costs.

6.3 LNG Pricing Dynamics

6.3.1 Long-Term Pricing

Long-Term pricing dynamics vary quite widely between the Atlantic and the Pacific Basins because of vastly different market dynamics.

LNG suppliers have traditionally aimed to price LNG against the competing fuel that it would replace. Consequently, in the Pacific Basin, LNG has historically included a price for long-term contracts that was indexed to fluctuations in oil prices. Although pricing formulas have evolved over the past 40 years, recent pricing formulas for long-term contracts have taken the following form:

Slope x Japan Custom Clearing Price + a

Where:

- Slope – expressed as a percentage to convert price from US$ per Barrel to US$ per million Btu. The typical slope in recent long-term SPA's has been 13 – 14.85% range (oil parity would imply a slope of 17.2%).

- Japan Custom Clearing Price (JCC) – average cost of petroleum products imported into Japan and reported monthly by Japanese customs in US$ per barrel. In November 2013, JCC was reported by Japanese customs as $112.71 per Barrel. Brent for the same month was $108 per barrel.

- a – usually a fixed amount expressed in US$ per million Btu that has historically reflected the cost of shipping, but is a negotiated term that may reflect other economic factors

In the Atlantic Basin, long-term LNG contract in Europe used to be linked to a basket of petroleum products to reflect the traditional pricing of long-term natural gas contract with Europe's traditional gas suppliers (Russia, Norway, and Algeria). A reasonable proxy for this type of pricing is ~12% x Brent. However, as discussed in an earlier section, European gas pricing mechanics have evolved to reflect actual supply and dynamics for natural gas in each market. Consequently, pricing for many European gas markets has become delinked from oil prices and therefore European LNG buyers' expectations are to price LNG against the spot price of natural gas in their respective markets. LNG suppliers have resisted this pricing framework and have continued to insist on oil-linked pricing. Consequently, there have been very few long-term LNG contracts signed in the past several years in Europe and most of the LNG purchases have been short-term transactions.

In South America, natural gas markets tend to be less mature or regulated by the government. Consequently, LNG pricing mechanisms vary widely. In Chile, after an international tender, the price of LNG imported was linked to diesel as it is the fuel substitute. Argentina procures LNG in the short-term market and conduct tenders on a regular basis. Pricing for LNG tends to be linked to Henry Hub (price of natural gas in US) with a significant premium to reflect demand for short-term LNG cargoes in the rest of the world and other market specific factors (delivery logistics, credit risk, etc.).

LNG imported into the U.S. was priced against the price of natural gas in the markets downstream of the LNG import terminals (Henry Hub). Most of the LNG volumes were effectively imported on a spot basis as gas in the U.S. is generally not traded on a long-term basis (virtually all gas volumes are contracted on a monthly and daily basis).

Because of the shale gas revolution, virtually no LNG is imported in the U.S. and all but one of the existing LNG import terminals are being re-developed into LNG export projects. The commercial structure of these would-be export projects is quite different from LNG export projects in the rest of the world. Most US export projects are tolling facilities where the capacity holder would purchase gas in the market and deliver it to the liquefaction plant by arranging pipeline transportation. The LNG project will then take its customers' natural gas, liquefy it for a fee and redeliver the LNG to its customers' LNG carriers. For this tolling model the resulting cost of LNG would therefore be:

Price of Natural Gas (Henry Hub) + cost of fuel for liquefaction + Liquefaction Tolling Fee + Cost of pipeline transportation from the market to the plant

In the 20-year contracts signed by Sabine Pass and its LNG buyers (BG, GasNatural Fenosa, KOGAS, Gail, Total, Centrica), the price was 115% x Henry Hub + \$2.25 - \$3. At the current price for Henry Hub (approximately \$4.00 per MMBtu), this would yield a price of approximately \$6.85 to \$7.60 per MMBtu on a Free on Board (FOB) basis. Although these prices would seem quite low compared to oil-linked prices that are typical for long-term contracts in the Pacific Basin, this pricing is only available to those companies that have contracted on a long-term basis (20 years) for the liquefaction tolling capacity and are actively involved in the US gas market to purchase natural gas to liquefy. Should any of these companies elect to resell US produced LNG from their portfolios, they would very likely seek "market" pricing and capture any spread between the cost of the US LNG supply and the market sale price. They are also taking the long-term risk that US gas prices may increase significantly and render US produced LNG much more expensive. Consequently, the development of liquefaction capacity in North America does not guarantee that LNG will be available to buyers on a Henry Hub basis as those Portfolio Suppliers that have secured LNG supplies from North American projects would prefer to sell LNG on an oil-indexed basis.

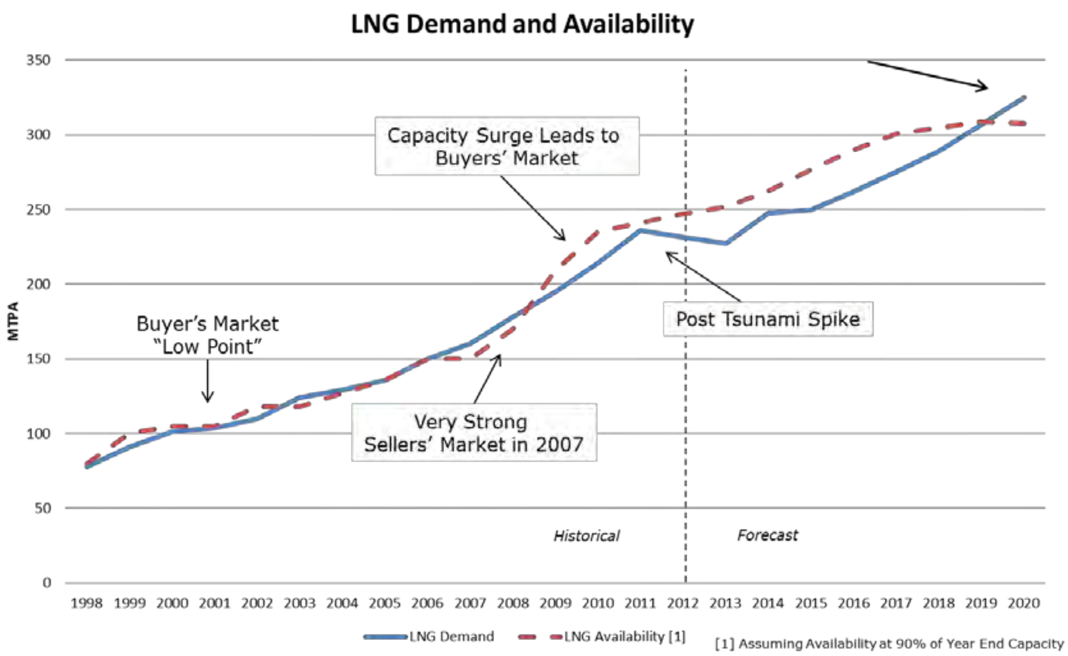
The development of LNG export project with this tolling structure has introduced a new pricing dynamic in the Pacific Basin. Since several Asian buyers have already contracted for liquefaction tolling capacity in the US, most buyers are now expecting that pricing formula should include a portion that is linked to Henry Hub instead of oil. There are rumours that some LNG suppliers have reluctantly agreed to some concessions in this regard for long-term contracts with large and credit worthy buyers.

Almost all LNG Sale and Purchase Agreements (SPA) are the result of a negotiation process where pricing formula and other very important commercial aspect of the contract are agreed to by the buyer and seller. This includes negotiations on pricing level, pricing indexation, pricing floors and ceiling, pricing re-openers, Buyer's liability for failure to take the LNG (Take-or-Pay liability), Seller's liability for failure to deliver LNG, delivery schedule flexibility, term of contract, contract annual volumes, minimum and maximum lot volumes, make-up mechanisms for any take-or-pay events, force majeure, etc. The final terms and conditions of these contracts are most often kept confidential between buyers and sellers and therefore there is little pricing transparency for long-term LNG contracts.

Bargaining leverage varies between buyers and suppliers depending on many factors. One of the important factors is the current, or near/mid-term, projected supply and demand balance at the time of the negotiations. Exhibit 6-10 below provides an indication of how market cyclicality has historically created leverage for buyers (Buyer's market) or created leverage for sellers (Seller's market).

For example, in the early 2000's, a slack in demand from traditional Asian Buyers in Japan and South Korea, enable Chinese buyers to negotiate a very low price for LNG from the Tangguh LNG project in Indonesia. Chinese buyers were able to leverage their position because of the desire for Tangguh's project sponsors to sanction the project. In 2007, the market became a very strong Seller's Market because of a slack in new projects coming on line and a temporary spike in demand from Japan caused by a disruption in nuclear power generation as a result of an earthquake.

Exhibit 6-10: LNG Market Cyclicality



6.3.2 Short-Term Pricing

As was discussed in Section 6.2, approximately 25% of total LNG volumes (~60 MTPA in 2012) are short-term transactions (less than 4 years). Although the contractual process may be more streamlined for these transactions than for long-term contracts, these transactions are also the result of a negotiation on price and other terms. The final terms and conditions of each transaction are generally kept confidential by both buyers and sellers.

Since 2010, several energy publications have sought to provide more transparency for sales of individual cargoes for delivery one to two month in the future. Platts is one of these companies that publishes pricing markers for Asia (DES Japan/Korea Marker – JKM), Southwest Europe (DES Southwest Europe Marker – SWE), and Northwest Europe (DES Northwest Europe Marker). Each of these markers is derived by surveying buyers and sellers and collecting either the price of the cargo that has been agreed to, or the price at which buyers and sellers would be willing to transact. Exhibit 6-11 below provides the monthly averages for JKM, SWE and NWE since Platts started to publish these markers.

Exhibit 6-11: Platts JKM, SWE and NWE LNG Price Markers (monthly average of daily reported prices) [35]

Prices for multi-year short-term transactions tend to be similar to long-term prices although are more prone to reflect near-term supply/demand balance. In other words, if sellers perceive a tight market over the term of the agreement, they will expect prices that are no less than long-term prices. There were some short-term transactions back in 2007 (which was perceived as a very strong seller's market) where the price was actually higher than usual long-term prices (reflected by a larger slope). Alternatively, in 2010-2011 timeframe, when the market was perceived as buyer's market, several short-term deals were agreed to at discounted prices from typical long-term prices (reflected by a small slope).

6.4 Potential Supply Sources for Mauritius

The approach for securing LNG supplies and, therefore, the potential sources of LNG for Mauritius will be heavily influenced by its volume requirements. Most LNG Portfolio Suppliers have minimum volume thresholds for entering into medium and longer term LNG SPA's. Although these minimum thresholds vary from supplier to supplier, most suppliers would prefer minimum contract volumes of 0.5 MTPA (approximately equivalent to seven or eight cargoes annually). Some Portfolio Suppliers, are willing to entertain smaller contracts in the order of 0.25 to 0.3 MTPA.

Similarly, the sponsors of new liquefaction projects (many of whom could be considered Portfolio Suppliers) tend to seek larger long-term SPA's with credit worthy buyers to support the large capital commitments that are required to build liquefaction projects. Although preferences will vary, most new projects would seek customers with demand greater than 1 MTPA.

LNG Traders will most likely consider supplying smaller volumes of LNG, either on an individual or multiple cargo basis. Up until now, LNG Traders have mostly engaged in shorter-term supply agreements as most have limited longer-term commitments for LNG supplies and shipping capacity. However, some of these companies are aggressive participants in tenders for longer-term supplies and some may make representations that they have commitments for LNG volumes on a long-term basis. Such representations should be carefully examined as part of the due diligence process to assess the potential supply risks.

Exhibit 6-12 below provides some background data on liquefaction plants currently in operations, under construction, or expected to be sanctioned in 2014. In terms of logistics, the closest potential sources of LNG for Mauritius would be West Africa, Middle East and Australia. However as the last column (Supply Availability Status) demonstrate, LNG volumes from these projects have already been sold either directly to end-users in Europe and Asia, or to Portfolio Suppliers. In the event that additional volumes are available, they tend to be sold either into the project's sponsors marketing affiliates' supply portfolio, or on the spot market.

Exhibit 6-12: Global Liquefaction Project Summary [31]

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Atlantic						
Atlantic	Algeria	Bethioua GL-1Z	Sonatrach	13.4	5,500 nm	Volumes marketed and sold by Sonatrach
Atlantic	Algeria	Gassi Touil (GL3Z)	Sonatrach	4.7	5,500 nm	Volumes marketed and sold by Sonatrach
Atlantic	Algeria	Skikda	Sonatrach	7.9	5,500 nm	Volumes marketed and sold by Sonatrach
Atlantic	Angola	Angola LNG	Chevron (36.4%), Sonangol (22.8%), BP (13.6%), Total (13.6%), ENI (13.6%)	5.2	5,000 nm	Volumes marketed and sold by Angola LNG Marketing (Joint shareholder decisions)
Atlantic	Egypt	Damietta	SEGAS (Union Fenosa Gas 80% (50/50 Union Fenosa & ENI), EGAS 10% and EGPC 10%)	5.0	5,500 nm	Sold out to BG, BP and Gas Natural Fenosa (production shortages due to insufficient feed gas)
Atlantic	Egypt	Idku - Egyptian LNG	BG (35.5%), Petronas (35.5%), EGAS (12%), EGP (12%), GDF (5%)	7.2	5,500 nm	Sold out to BG and GdF Suez (production shortages due to

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
						insufficient feed gas)
Atlantic	Equatorial Guinea	Bioko - EG LNG	Marathon (55%), Sonagas (25%), Mitsui (8.5%), Marubeni (6.5%), Ruhrgas (5%)	3.7	5,000 nm	Sold out to BG
Atlantic	Nigeria	NLNG	NNPC (49.0%), Shell (25.6%), Total (15.0%), ENI (10.4%)	21.9	5,000 nm	Sold out to Shell, Total, BG, GdF Suez, Gas Natural Fenosa, GALP and Iberdrola
Atlantic	Norway	Snohvit	Statoil (36.79%), Petoro (30.0%), Total (18.4%), GDF (12.0%), RWE (2.81%)	4.2	8,300 nm	Sold out to GdF Suez, Iberdrola, Statoil and Total
Atlantic	Trinidad	Atlantic LNG	NGC (10.0%), BP (34.0%), BG (26.0%), Shell (20.0%), GdF Suez (10.0%)	11.8	7,640 nm	Sold out to NGC, BG, BP, Gas Natural Fenosa, GdF Suez, Repsol and Shell
Atlantic	US Gulf Coast	Cameron	Sempra (50.2%), GDF SUEZ, Mitsubishi and Mitsui each to acquire 16.6-% equity	13.2	9,940 nm	Expected FID 2014; sold out to Mitsubishi, Mitsui and GdF Suez
Atlantic	US Gulf Coast	Freeport	Freeport LNG (20%), Zachry American Infrastructure (55%), Dow Chemical (15%), Osaka Gas (10%)	13.2	US Gulf Coast - 9,940 nm	Expected FID 2014; sold out to Osaka Gas, Chubu Electric and BP

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Atlantic	US Gulf Coast	Sabine Pass	Cheniere	18.0	US Gulf Coast - 9,940 nm	Sold out to BG, Gas Natural Fenosa, Kogas, Total, GAIL and Cheniere Marketing
Middle East						
Middle East	Oman	Oman LNG	Oman (51.0%), Shell (30.0%), Mitsubishi (2.77%), Mitsui (2.77%), Itochu (0.92%), Total (5.54%), Korea LNG (5.0%), Partex (2.0%)	9.4	3,300 nm	Majority is sold out to Japanese and Korean utilities with smaller volumes going to BP
Middle East	Oman	Qalhat LNG	Sultanate (46.84%), Oman LNG (36.8%), Union Fenosa 7.36%, Mitsubishi (3%), Itochu (3%), Osaka Gas (3%))	3.7	3,300 nm	Majority is sold out to Japanese and Chinese buyers with smaller volumes going to Gas Natural Fenosa
Middle East	Qatar	Qatargas	QP (65.0%), Exxon (10.0%), Total (10.0%), Mitsui (7.5%), Marubeni (7.5%)	10.0	3,300 nm	Sold out to Japanese utilities and Gas Natural Fenosa
Middle East	Qatar	Qatargas II	QP (65.0%), Exxon (18.3%), Total (16.7%)	15.6	3,300 nm	Sold out to PGNiG, South Hook Gas (and gas marketing via Exxon), Total and Japanese Utilities
Middle East	Qatar	Qatargas III	QP (68.5%), COP (30%), Mitsui (1.5%)	7.8	3,300 nm	Sold to COP, CNOOC and Japanese utilities

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Middle East	Qatar	Qatargas IV	QP (70.0%), Shell (30.0%)	7.8	3,300 nm	Volumes sold to Centrica, Dubai Supply Authority, Marubeni, Petrochina, Shell and Petronas
Middle East	Qatar	RasGas	QP (63.0%), Exxon (25.0%), KOGAS (5.0%), Itochu (4.0%), LNG Japan (3.0%)	6.6	3,300 nm	Sold out to Kogas and Petronet
Middle East	Qatar	RasGas II	QP (65.0%), Exxon (30.0%), Chinese Petroleum (5%)	14.1	3,300 nm	Volumes sold to EDF, Edison, Endesa, Kogas and Petronet
Middle East	Qatar	RasGas III (ExxonMobil)	QP (70.0%), Exxon (30.0%)	15.6	3,300 nm	Sold out to CPC, Kogas and Exxon
Middle East	UAE	Abu Dhabi LNG (Adgas LNG)	ADNOC 70%, Mitsui 15%, BP 10%, Total 5%	5.8	3,300 nm	Majority of volumes sold to TEPCO with smaller volumes going to Gazprom Marketing
Middle East	Yemen	Yemen LNG	YGC (16.73%), Total (39.62%), Hunt (17.22%), South Korea Consortium [SK (9.55%), Hyundai (5.88%), Kogas (6.0%)], Yemen GGASSP (5.0%)	6.7	3,300 nm	Sold out to GdF Suez, Kogas and Total
Pacific						

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Pacific	Alaska	Kenai	COP	1.4	Alaska - 10,070 nm	Intermittent Operation, COP has control of volumes
Pacific	Australia	APLNG (COP)	Origin (37.5%), COP (37.5%), Sinopec (25%)	9.0	E. Australia - 4,360 nm	Sold out to Sinopec and Japanese utilities. COP also has some of the volumes
Pacific	Australia	Darwin	COP (56.72%), ENI (11%), Santos (11.4%), INPEX (11.3%), Tokyo Gas (3.36%), TEPCO (6.72%)	3.6	C. Australia - 4,260 nm	Majority of volumes sold to Japanese utilities
Pacific	Australia	GLNG (Santos)	Santos (30%), Petronas (27.5%), Total (27.5%), Kogas (15%)	7.8	E. Australia - 4,360 nm	Volumes sold to Kogas and Petronas. Santos also has some of the volumes
Pacific	Australia	Gorgon LNG	Chevron (47.33%), Exxon (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%), Chubu Electric Power (0.417%)	15.6	W. Australia - 3,300 nm	Sold to buyers in Japan, China and Korea. Shell, Chevron and Exxon have some of the volumes
Pacific	Australia	Ichthys LNG	Inpex (63.445%), Total (30%), Osaka Gas (1.2%), Tokyo Gas (1.58%), Chubu Electric (0.74%), Toho Gas (0.42%), CPC (2.625%)	8.4	C. Australia - 4,260 nm	Sold out to Japanese utilities
Pacific	Australia	NW Shelf	Woodside (16.67%), BHP (16.67%), BP (16.67%), Chevron (16.67%), Shell (16.67%), MIMI (Mitsubishi 8.33%, Mitsui 8.33%, CNOOC (only in fields)	16.3	W. Australia - 3,300 nm	Majority is sold out to Japanese utilities

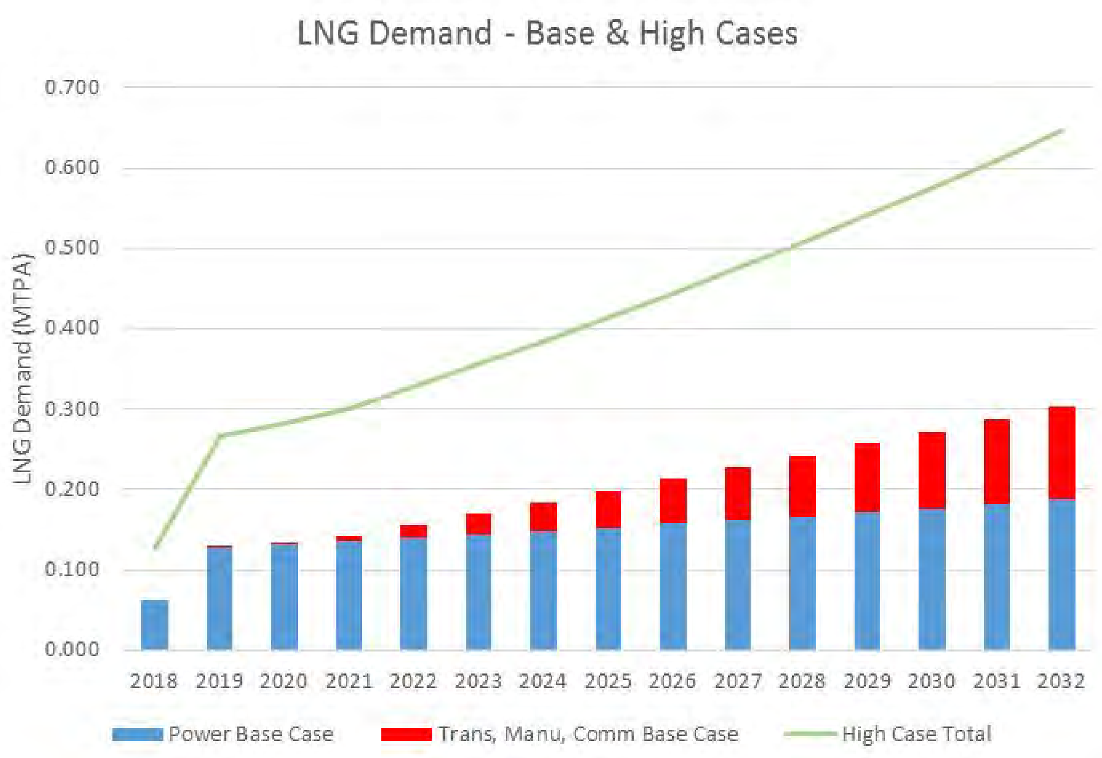
Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Pacific	Australia	Pluto LNG	Woodside (90%), Tokyo Gas (5%), Kansai (5%)	4.3	W. Australia - 3,300 nm	Majority of volumes sold to Japanese utilities
Pacific	Australia	Prelude	Shell (67.5%), Inpex (17.5%), Kogas (10%), CPC (5%)	3.6	C. Australia - 4,260 nm	Sold out to buyers in Japan, Taiwan and Korea. Shell also has some of the volumes
Pacific	Australia	Queensland (BG)	BG (50%), CNOOC (50%)	8.5	E. Australia - 4,360 nm	Majority of volumes sold to CNOOC. Tokyo Gas also has some small volumes
Pacific	Australia	Wheatstone LNG	Chevron (64.14%), Apache (13%), Kufpec (7%), Shell (6.4%), Kyushu Electric (1.46%), PE Wheatstone (8%)	8.9	W. Australia - 3,300 nm	Half of the volumes sold to TEPCO. Chevron also has volumes
Pacific	Brunei	Lumut	Brunei (50%), Mitsubishi (25%), Shell (25%)	6.7	Indonesia/Malaysia - 4,000 nm	Sold out to Japanese and Korean utilities
Pacific	Indonesia	Arun	Pertamina (55%), Exxon (30%), JILCO (15%)	12.8	Indonesia/Malaysia - 4,000 nm	Sold out to Japanese and Korean utilities
Pacific	Indonesia	Bontang	Pertamina (55%), Vico (20%), Total (10%), JILCO (15%)	22.5	Indonesia/Malaysia - 4,000 nm	Capacity sold out to Japanese buyers with the rest of the volume diverted to the domestic market

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Pacific	Indonesia	Donggi-Senoro LNG	Mitsubishi (45%), Kogas (15%), Pertamina (29%), Medco (11%)	2.1	Indonesia/Malaysia - 4,000 nm	Sold out to Japanese and Korean utilities
Pacific	Indonesia	Tangguh	BP (37.16%), Mitsubishi (Inpex) (16.3%), CNOOC (13.9%), Talisman (3.06%), Nippon Oil (12.23%), Kanematsu (10%), LNG Japan (7.35%)	7.6	Indonesia/Malaysia - 4,000 nm	Sold out to buyers in Japan, China and Korea. Sempra also has some of the volumes
Pacific	Malaysia	Kanowit FLNG	Petronas	1.2	Indonesia/Malaysia - 4,000 nm	Volumes are mainly to be sold into the domestic market
Pacific	Malaysia	MLNG Dua/Satu	Petronas (60%), Shell (15%), Mitsubishi (15%), Sarawak (10%)	17.1	Indonesia/Malaysia - 4,000 nm	Sold out to Japanese utilities
Pacific	Malaysia	MLNG Tiga	Petronas (60%), Shell (15%), Nippon (10%), Diamond Gas (5%), Sarawak (10%)	10.4	Indonesia/Malaysia - 4,000 nm	Sold out to Japanese, Chinese and Korean utilities
Pacific	Papua New Guinea	PNG LNG (Hides field)	Exxon Mobil (33.2%), Oil Search LTD (29%), Santos (13.5%), Indept. Public Bus. Corp (16.6%), Nippon Oil Corp (4.7%), MRDC (2.8%), Petromin PNG (0.2%)	6.9	Indonesia/Malaysia - 4,000 nm	Sold out to buyers in Japan, Taiwan and China. Exxon also has some of the volumes

Basin	Location	Project Name	Participants	Design Capacity (MTPA)	Approximate Distance from Mauritius	Supply Availability Status
Pacific	Peru	Peru LNG	Hunt (50%), SK (20%), Shell (20%), Marubeni (10%)	4.4	Peru - 8,560 nm	Sold out to Shell and Repsol
Pacific	Russia	Sakhalin II	Gazprom (50%), Shell (27.5%), Mitsui (12.5%), Mitsubishi (10%)	9.6	Russia - 6,650 nm	Sold out to Japanese utilities. Shell has some of the volumes

Exhibit 6-13 below illustrates the combined base and high case demand scenarios for power and the transportation/industrial/commercial sectors. For the power sector, the Base Case demand projection is based on the base case (new 100 MW GTCC, 6 Ft Victoria and 3 St Louis unit conversions and 4 new St Louis 15MW units) and the base electric demand growth scenario defined in Exhibit 1-35 and Exhibit 1-36 respectively. For the High Case, demand projections are based on the Base Case plus replacement of the unconvertible units (Ft George G1-5, Ft Victoria G8-9, St Louis G1-5) and the high electric demand growth scenario defined in Exhibit 1-37and Exhibit 1-38 respectively. For the transportation, manufacturing and commercial sectors, the results are based on the case definition and demand projections in Exhibit 2-15 and Section 2.6 respectively.

Exhibit 6-13: LNG Demand Projections for Base and High Cases



Under the Base Case, the annualized demand in 2019 (demand shown for 2018 in Exhibit 6-13 reflect the timing for the start-ups of the new power plant and of the infrastructure required to serve the transportation, industrial and commercial sectors) is projected to be approximately 0.13 MTPA. Although it is expected to grow as demand for power in Mauritius grows and as demand from the transportation, manufacturing and commercial sectors grow, demand is projected to remain below the expected Portfolio Suppliers' minimum volume threshold of 0.25 MTPA for over ten years. Consequently, it is unlikely that LNG supplies could be sourced for Mauritius under a long-term contract from Portfolio Suppliers by the expected start date of the project. However, Mauritius should be able to secure LNG cargoes on a short-term basis in the short-term/spot market by implementing annual tenders for LNG volumes. This procurement approach is not unusual and has been used by other new buyers of LNG for multiple different reasons. For the last several years, Argentina has been purchasing its relatively large LNG volumes (in excess of fifty cargoes per year) in the short-term/spot market primarily to manage domestic demand volatility and because of credit worthiness concerns with LNG suppliers (suppliers' concerns about Argentina's credit status has severely limited the suppliers' interest in entering into long-term SPA's with Argentina). In Thailand, PTT initially secured its LNG supplies in the spot market because of its relatively low initial demand and expectations of better pricing in the short-term market.

As has been discussed above, the likeliest suppliers to Mauritius would be Portfolio Suppliers and LNG Traders. Exhibit 6-14 below, provides a list of potential Portfolio Suppliers and LNG Traders that may be interested in supply LNG to Mauritius on a short-term/spot basis. Once demand grows to reach 0.25 MTPA and greater, it is very likely that Mauritius could secure long-term supply commitments from Portfolio Suppliers.

Exhibit 6-14: Potential Suppliers of Short-Term/Spot LNG to Mauritius [31]

Portfolio Player	Supply Source
BG	Atlantic LNG, Queensland, Idku, EG LNG, NLNG, Damietta, Sabine Pass
BP	Atlantic LNG, Oman LNG, Damietta, Freeport
Chevron	Wheatstone, Gorgon
COP	Qatargas III, APLNG, Alaska
XOM	Qatargas II, Rasgas III, PNG, Gorgon
GdF Suez	Atlantic LNG, Yemen, Idku, Skikda, Snohvit, NLNG
Gas Natural Fenosa	NLNG, Atlantic LNG, Qatargas, Sabine Pass, Damietta
Petronas	GLNG, Kanowit FLNG, MLNG, Idku
QatarGas & RasGas	Flexible volumes with IOC possibilities
Repsol	Peru LNG, Atlantic LNG
Shell	Gorgon, Atlantic LNG, Prelude FLNG, Peru LNG, Qatargas IV, Sakhalin II, NLNG
Total	Qatargas II, Yemen, NLNG, Snohvit, Sabine Pass
Citi	No long term supplies known
Morgan Stanley	No long term supplies known

Portfolio Player	Supply Source
JPMorgan	No long term supplies known
Vitol	No long term supplies known
Trafigura	No long term supplies known
Gunvor	No long term supplies known
Koch	No long term supplies known
Macquarie	No long term supplies known

Under the high case scenario, the annualized LNG demand in 2019 is project to be 0.27 MTPA which matches the expected Portfolio Suppliers' minimum volume threshold of 0.25 MTPA. Consequently, if it chose to do so, Mauritius could potentially attract the attention and interest of Portfolio Suppliers to commit long-term supplies. Although most suppliers would prefer to engage into direct negotiations with a potential buyer, it is common for buyers to conduct structured tender processes to source long-term LNG and most Portfolio Suppliers generally agree to participate in such processes. It should be noted that tender processes need to be carefully designed and executed to allow for sufficient flexibility to account for the fact that LNG is not a true commodity like oil, heavy fuel oil or diesel.

Given Mauritius' proximity to the newly discovered significant natural gas resources in East Africa, specifically Mozambique and Tanzania, new LNG projects being developed in those countries might be logical sources of LNG for Mozambique. These projects are still in various stages of development and have yet to be sanctioned by the host governments and international partners that hold exploration and production licenses. First LNG volumes are not expected until 2018 at the earliest and most likely will slide into the 2020 timeframe. The sponsors of these projects, listed in Exhibit 6-15 below, are most likely seeking to sell the majority of their LNG supplies to large, established and credit-worthy buyers of LNG in order to provide the credit security required to borrow the tens of billions of dollars necessary to develop and construct the projects.

Exhibit 6-15: East Africa Project Sponsors

Country	Project	Sponsors
Mozambique	Mozambique LNG	Area 1: Anadarko, Mistui, ENH, Bharat Petroleum, Oil India Limited, ONGC, PTT Area 4: ENI, CNPC, GalpEnergia, KOGAS, ENH
Tanzania	TBD	BG, Ophir, Statoil, ExxonMobil
Tanzania	TBD	Shell

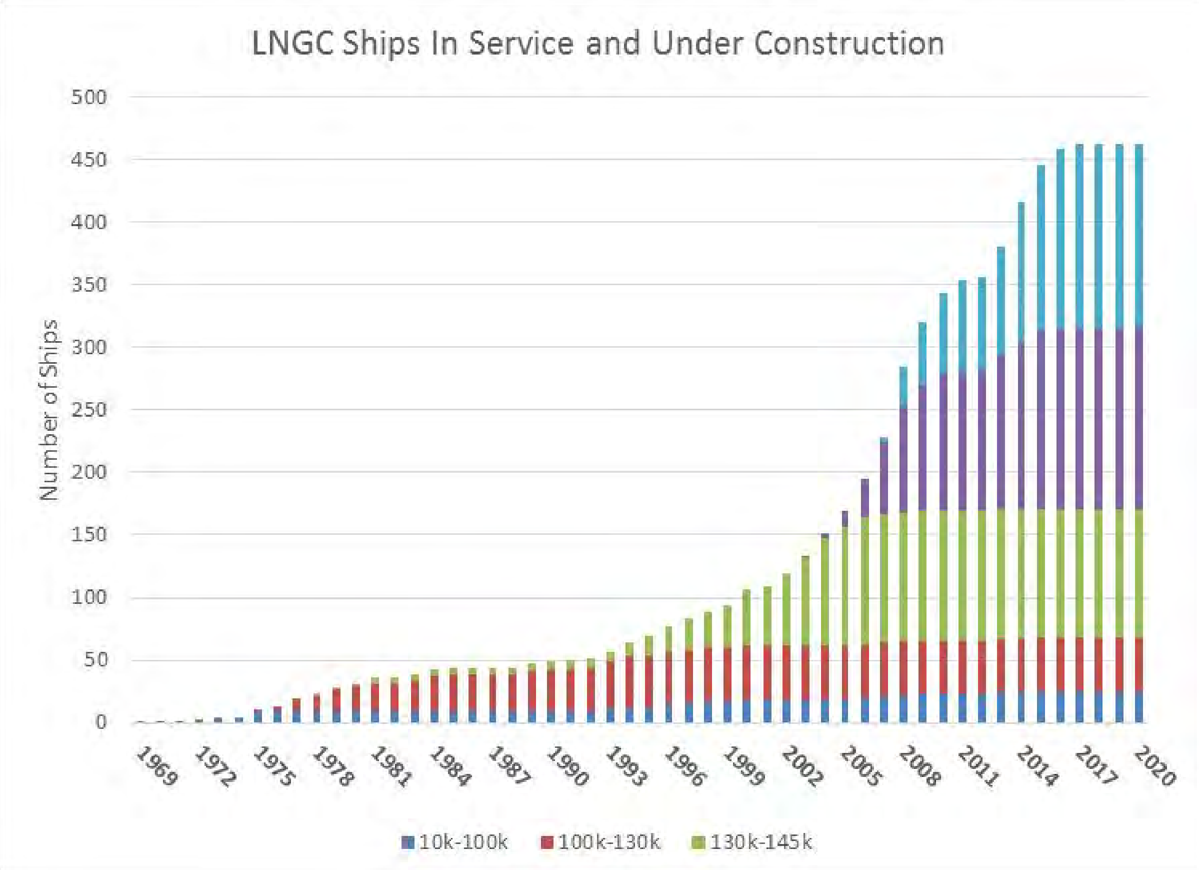
As has been discussed, the likeliest providers of LNG supplies to Mauritius will be Portfolio Suppliers which could include some of the participants in the East Africa LNG projects. However, Mauritius would compete with the rest of the world for those supplies and consequently, it should expect to pay “world” prices for LNG.

6.4.1 LNG Transportation Considerations

In general, Portfolio Suppliers prefer to sell LNG on a Delivered Ex-Ship basis (DES or Delivered At Terminal – DAT) because controlling shipping capacity provides the flexibility required to manage their supply portfolios and allows the suppliers to better mitigate transportation and operational risks associated with the sale and transportation of LNG. Some larger LNG buyers prefer to purchase LNG on a FOB basis for the same reasons (flexibility and risk mitigation), and the issue of transportation is often a carefully negotiated issue. In the case of smaller new buyers, like Mauritius, they likely will not have to necessary bargaining leverage to demand FOB sales, and, generally, do not have, nor want to develop, the necessary capabilities to manage LNG shipping operations. Consequently, LNG will in all likelihood be sold to Mauritius on a DES basis and the suppliers will be responsible for securing and managing the LNG transportation capacity necessary to deliver LNG to the LNG import terminal.

LNG shipping capacity has steadily increased to support the growth of the LNG market. When new projects are developed, new ships are typically ordered and chartered on a long-term basis by either the project company or the LNG off-takers to support the new volume deliveries. Portfolio Suppliers and large FOB buyers develop and manage portfolios of LNG transportation capacity to support their LNG supply portfolio and value optimization strategies, and increase or decrease shipping capacity as may be needed. As LNG ships age and become less efficient than newer vessels, they may be replaced by newer vessels in the shipping portfolios and become available for shorter-term charters. Exhibit 6-16 below, illustrates the growth of the global LNG shipping fleet as well as the trend of larger vessels being ordered and used to transport LNG.

Exhibit 6-16: Global LNG Shipping Fleet (ship size units are m^3 of storage capacity) [30]



6.4.2 LNG Suppliers Pricing Expectations

LNG suppliers tend to consider several factors when pricing LNG for delivery into new markets. As discussed in Section 6.3, most Portfolio Suppliers tend to prefer to sell LNG on an oil-indexed basis. Suppliers will often take into account the alternative fuel being used in the market, and price LNG accordingly, usually trying to maximize the price of LNG while still enabling LNG to be substituted. Another factor is the value they can achieve in alternative markets. Because of the mobility of LNG, suppliers will evaluate how to maximize the value of their portfolios by targeting sales to markets that maximise the value of the product. One method to evaluate this value is to compute the break-even netback price that a new market must yield in order to maintain the value of the LNG delivered and sold in alternative markets.

Exhibit 6-17 illustrates the breakeven netback price analysis for 2018 that suppliers may conduct to price LNG for Mauritius. The analysis returns the potential price that would have to be paid in Mauritius for LNG supplied from West Africa, the Middle East and Australia when compared to long-term prices that suppliers could expect to yield in Europe and Asia. The pricing formula used to illustrate the long-term price in Asia is 14.5% x Brent + US$0.60. The pricing formula used to illustrate the long-term price in Europe is 11.8% x Brent - US$0.50 (It should be noted that although LNG suppliers have a strong preference to price LNG into Europe using an oil index, European LNG buyers are no longer willing to accept oil indexation as prices of gas in their markets may no longer reflect oil indexation. However, for the purpose of this analysis, the “old” oil indexation formula is used because there is no readily available long-term projection of price for natural gas in Europe. The negative US$0.50 per MMBtu reflects the full lifecycle cost of LNG import capacity in European terminals which needs to be taken into account as it is a cost that a LNG supplier, or its customer, would be expected to pay to be able to access the European gas market). Galway’s shipping model has been used to compute shipping costs to the alternative markets and to Mauritius. The price projection for Brent is from the U.S. Department of Energy’s Energy Information Agency’s 2014 Annual Energy Outlook (Preliminary edition) (“AEO 2014”). AEO 2014 was utilized for this analysis because the World Bank’s January 2014 Commodity Markets Outlook only provides projections for crude oil price until 2025. Exhibit 6-18 below includes the crude oil price projections from the AEO 2014 and the Commodity Markets Outlook reports.

Exhibit 6-17: LNG Supplier Break-Even Netback Analysis

Netback Cost to Primary European Markets - Low Case (US$/mmbtu)

	West Africa (NLNG)	Middle East (Ras Laffan)	Australia (NW Shelf)
Ex-Ship Sales Price		$11.48	
Shipping Cost	$0.98	$1.67	-
Netback to Europe	$10.50	$9.81	-

Breakeven Cost for Alternative Mauritius Market (US$/mmbtu)

	West Africa (NLNG)	Middle East (Ras Laffan)	Australia (NW Shelf)
Netback to Europe	$10.50	$9.81	-
Shipping Cost	$1.09	$0.78	-
Breakeven Price	$11.59	$10.59	-

Netback Cost to Primary Asia Markets - High Case (US$/mmbtu)

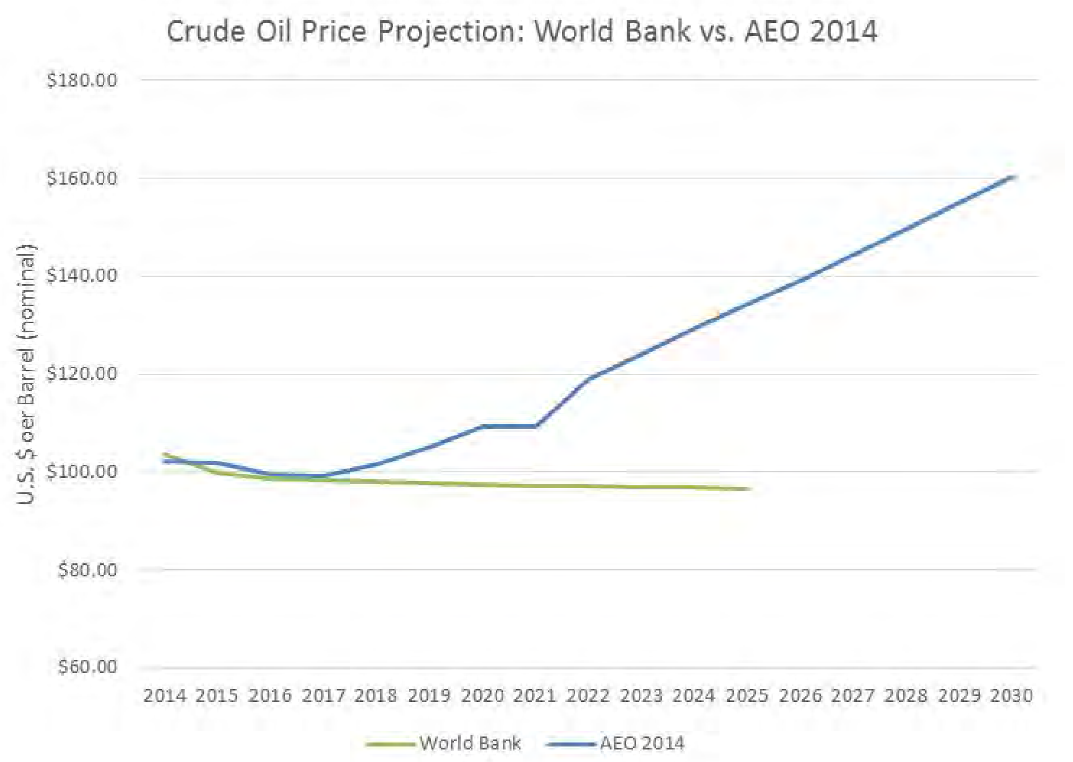
	West Africa (NLNG)	Middle East (Ras Laffan)	Australia (NW Shelf)
Ex-Ship Sales Price		$15.32	
Shipping Cost	$2.51	$1.54	$0.95
Netback to Europe	$12.81	$13.78	$14.37

Breakeven Cost for Alternative Mauritius Market (US$/mmbtu)

	West Africa (NLNG)	Middle East (Ras Laffan)	Australia (NW Shelf)
Netback to Asia	$12.81	$13.78	$14.37
Shipping Cost	$1.16	$0.82	$0.84
Breakeven Price	$13.97	$14.60	$15.21

Source: Galway Analysis

Exhibit 6-18: Crude Oil Price Projections AEO 2014 vs. World Bank January 2014



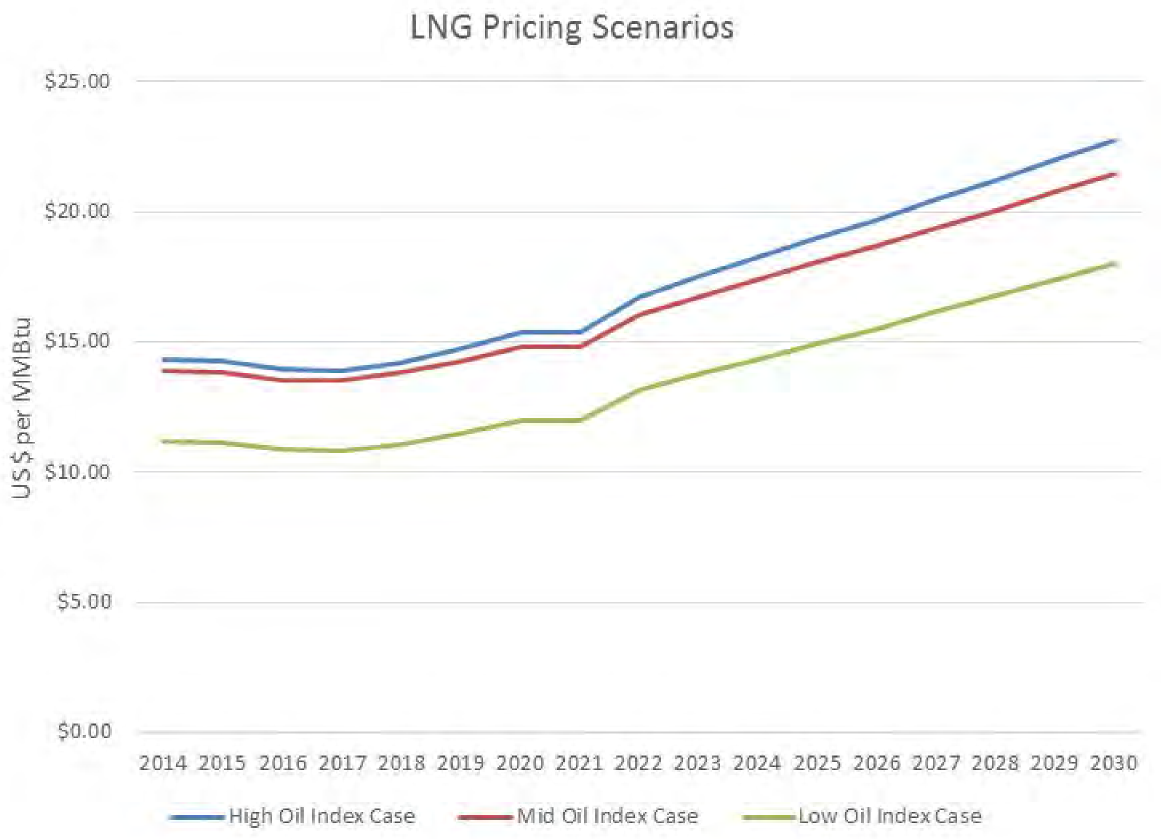
Source: U.S. DOE EIA and World Bank

Based on the netback analysis illustrated in Exhibit 6-15 above, the following pricing scenarios are deemed to represent a reasonable range of pricing for LNG delivered to Mauritius:

- High Oil-Index Case – 14.5% x Brent minus US$0.50
- Mid Oil-Index Case – 13% x Brent plus US$0.60
- Low Oil-Index Case – 11.8% minus US$0.90

Exhibit 6-19 below provides the projected LNG prices delivered to Mauritius for these three pricing scenarios.

Exhibit 6-19: Projected LNG Prices for Mauritius



Although price is a very important element of a SPA, other key terms are very important to consider as well when comparing LNG offers. It should be noted that it is very difficult to define a set of "standard" commercial terms in long-term contracts because each contract is negotiated to reflect the specific market conditions at the time of the negotiation as well as the specific requirements of the transaction. The following is a non-exhaustive list of commercial terms considerations:

- Contract Duration: As discussed above, it should be expected that Portfolio Suppliers would expect a term of at least 10 years for a long-term SPA
- Contract Volume and Flexibility: Contract volumes and how they can be impacted by specific events are carefully defined as well as any provisions for either buyer or seller to exercise flexibility to reduce or increase the contract quantity. In some cases, delivery profile flexibility can be discussed.

- Timing for First Commercial Delivery: this clause addresses when the contract is expected to start and in the case of deliveries to a new terminal will address how the 1st delivery date will be coordinated with the completion of the terminal.
- Transportation: DES or FOB structure is decided / negotiated.
- Buyer Take-or-Pay: It has been a common practice in long-term SPA's to include penalties for the buyer's unexcused failure to accept a delivery of LNG. This is commonly referred to as Take-or-Pay. Under the most severe structure, the buyer would be responsible for paying the full contract value for a LNG cargo that it has failed to accept, generally with rights to try to reschedule the cargo at a later time (make-up rights). At the other end of the spectrum, the penalty can be structured as liquidated damages that reflect the supplier's lost value on the cargo. These clauses are carefully negotiated and can be contentious.
- Seller Liability for Failure to Deliver: It has been a common practice in long-term SPA's to include penalties for the seller's unexcused failure to deliver a cargo. These penalties can take many forms but generally attempt to reflect the economic harm inflicted on the buyer by the seller's failure to deliver the LNG, often reflecting the incremental cost of fuel.
- Price Re-opener: In some contracts, supplier and buyer may agree to re-open the contract price under certain pre-agreed conditions. Negotiating these types of clauses can be contentious as both parties have very strong competing interests.
- Force Majeure: defines the conditions during which either party could claim to suspend some of their obligations under the SPA. When negotiating with a Portfolio Suppliers, these clauses can become more complex as negotiation focus on how events impact certain elements of their portfolio and their ability to claim force majeure.
- Scheduling: detailed provisions are included to address the scheduling of cargoes over each contract year and how binding schedules can or cannot be amended over the course of the year

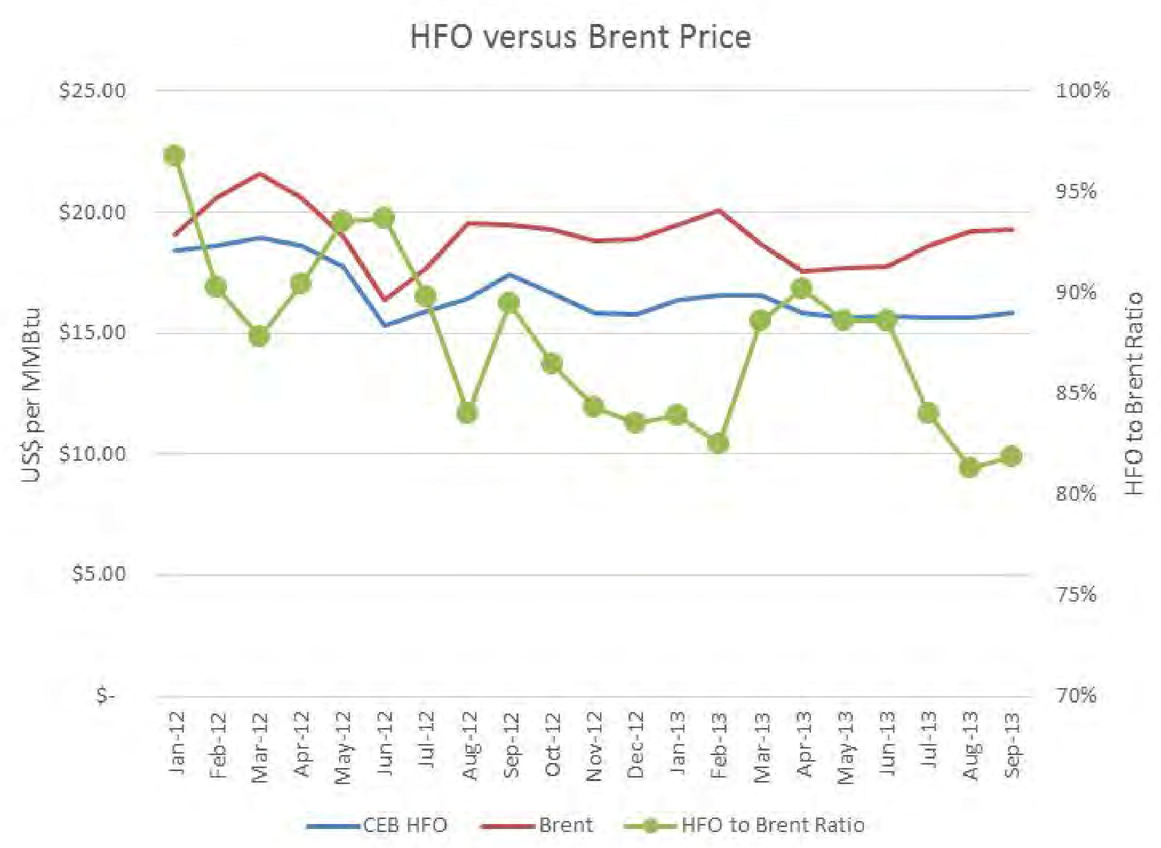
Other provisions address quality, measurement and testing, duties and taxes, choice of law, invoicing and payments, title and risk of loss, conditions precedent, liability cap, indemnity structure, etc. Long-term LNG SPA's are typically very long and detailed contracts and can take a significant amount of time to negotiate (sometimes as long as twelve months).

6.5 LNG Supply Availability vs. Demand (Critical Mass Assessment)

During the kick-off meeting for the LNG Pre-Feasibility Study project, CEB official indicated that one of the key drivers for undertaking a project to switch to LNG as a fuel for power generation would be the expectation that fuel cost savings can be realized to lower the cost of electricity in Mauritius. Consequently, the team has elected to compare the cost of regasified LNG delivered to CEB's power plants under the various pricing scenarios with the estimated cost of HFO, which is the current fuel and deemed to be the next best alternative fuel.

CEB provided some historical data for its cost for HFO. This data is represented in Exhibit 6-20 along with the cost of Brent crude (left vertical axis) and the ratio of the cost of HFO to the cost of Brent crude (right vertical axis). The price data has been converted from US$ per Barrel into US$ per MMBtu to facilitate the comparison.

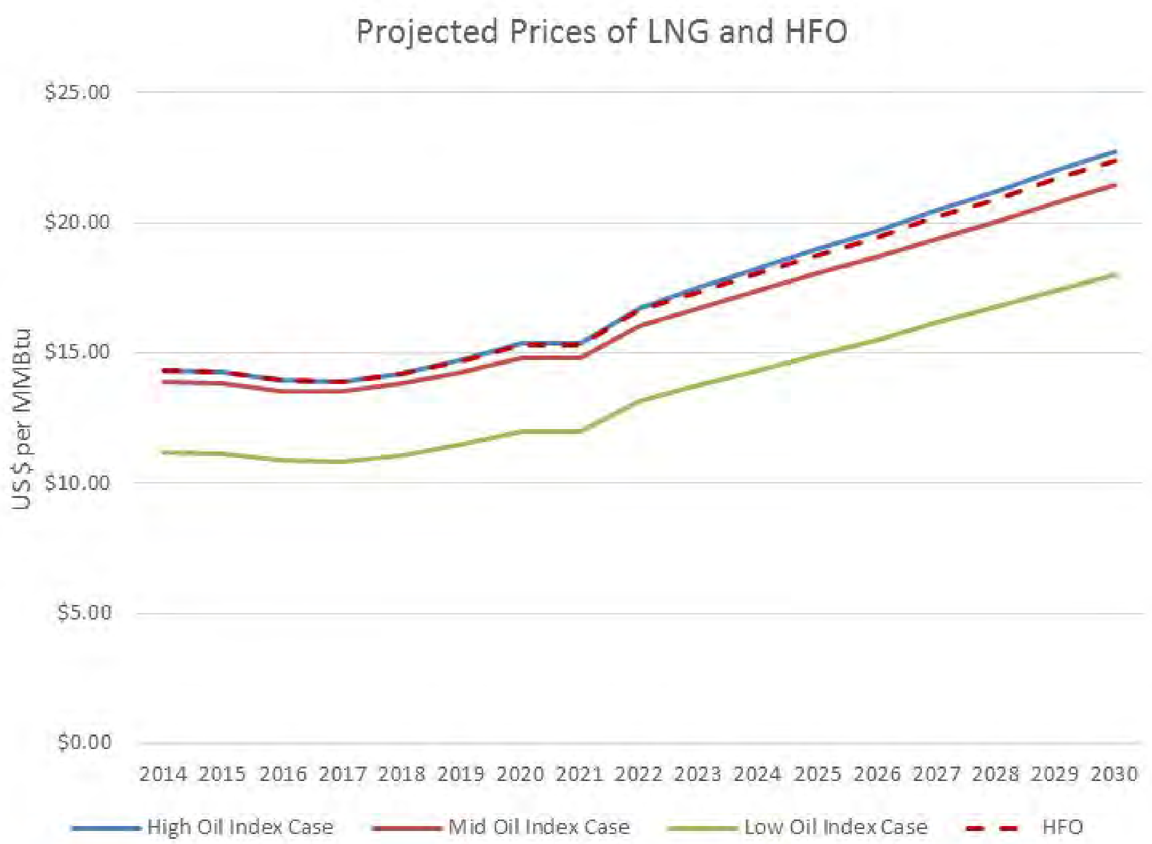
Exhibit 6-20: Comparison of Historical Price for Brent Crude and CEB's HFO Purchase Price [39] [40]



Over this limited time period, the HFO to Brent crude ratio has varied from 81% to 97% and averaged 88%. This ratio is fairly consistent with the ratio of 1% HFO New York Harbour to Brent crude prices which has averaged 90% from 2009 through 2013. Consequently, the 88% HFO to Brent Crude ratio has been used to project HFO prices by using the long-term price forecast for Brent crude published in AEO 2014 which is referenced in Exhibit 6-18 above.

Exhibit 6-21 below compares the projected cost of LNG for the three pricing scenarios represented in Exhibit 6-19 to the projected cost of HFO. It is clear from these projections that LNG will likely not be competitive with HFO for the high and mid pricing scenarios (even before adding in the costs for the LNG import terminal and infrastructure to distribute LNG or regasified LNG to CEB's power plant). Consequently, LNG may only be competitive versus HFO if it can be acquired under the low pricing scenario.

Exhibit 6-21: Projected DES LNG and HFO prices for Mauritius



Section 8 provides a detailed description of the method that was used to model the economics of the LNG import terminal. The resulting total annual costs to operate and maintain the terminal (including the cost of fuel used by the vessel), charter the FSRU, cover debt service, provide the return of equity as well as the return on equity, and pay taxes is included in Exhibit 6-22 below. These figures are presented on a calendar year basis.

Exhibit 6-22: Total Annual LNG Terminal Costs (US$ million per year)

Exhibit 6-23 below incorporates the unit cost for the LNG terminal with the LNG DES prices from Exhibit 6-19 and the Base and High Case volumes defined in Exhibit 6-13 and compares the resulting projected cost of regasified LNG delivered to CEB's plants (Burner Tip Cost) for these six cases to the projected DES cost of HFO.

Exhibit 6-23: Projected LNG Burner Tip Cost Cases versus DES HFO Cost (US$ per MMBtu)

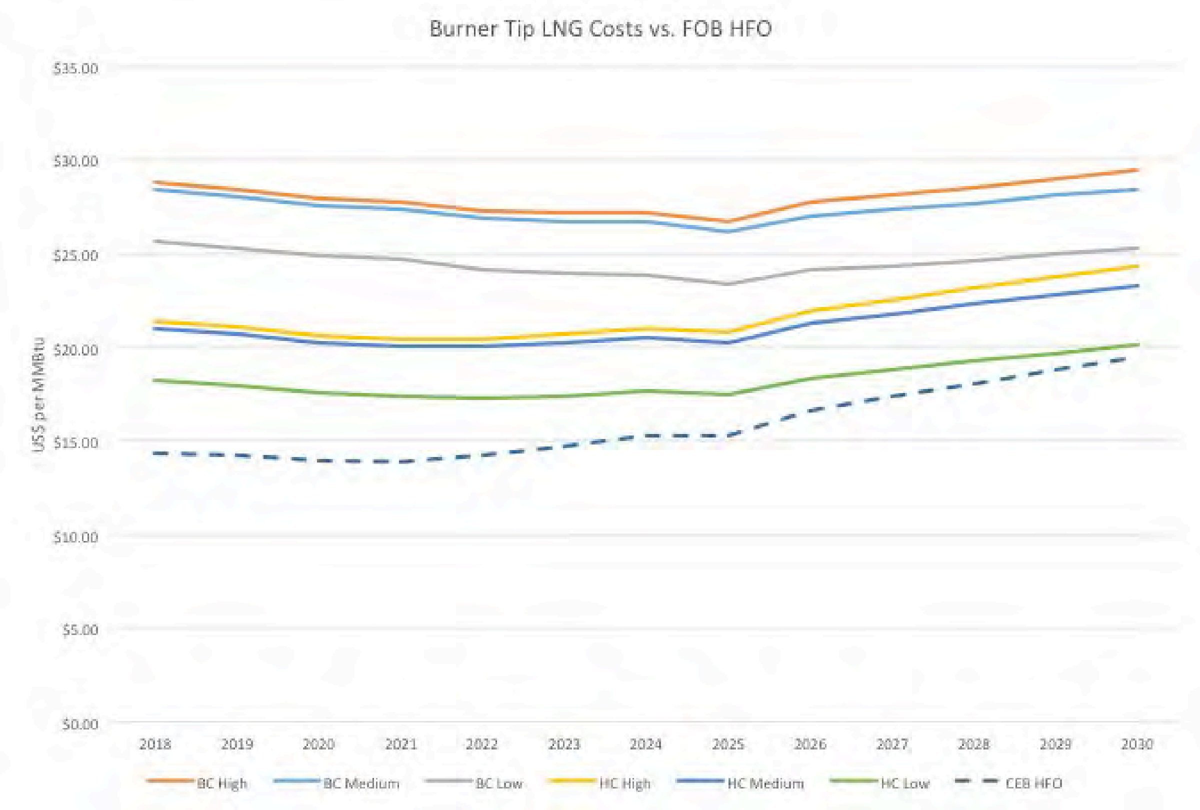


Exhibit 6-22 above clearly demonstrates the challenge to generate sufficient demand to develop the economies of scale for the LNG infrastructure that are necessary to lower the overall cost of LNG delivered to each plant and generate savings versus burning HFO. This conclusion is to be expected given the high annual costs for the LNG infrastructure and the relatively low volumes for the Base Case. However, even using the aggressive demand scenario (High Case) would not result in sufficient volumes in neither the near nor long-term to produce cost savings versus HFO..

As Exhibit 6-21 demonstrates, focusing on reducing terminal costs for the high and medium LNG pricing formulas would not impact on the competitiveness of LNG vs. HFO in Mauritius due to the very small spread between projected prices for LNG under the high and mid pricing scenarios and HFO. For the Low Pricing and Base Case volume scenario, annual terminal costs would have to be reduced by about 75% to reach a break-even cost with HFO. For the Low Pricing and High Case volume scenario, annual terminal costs would have to be reduced by about 55% to reach a break-even cost with HFO. One potential solution to significantly lower infrastructure fee is to reduce the CAPEX for those facilities by using small or mid-scale LNG terminal solutions (see reference in Section 3.4.4.1). Further evaluation would be required to assess whether a small or mid-scale LNG import and regasification solution would be able to yield such cost savings. However, as stated in Section

3.4.4.1, the team did not consider small scale LNG import terminal solutions for Mauritius because a) currently, there are no sources of LNG supply that would accommodate the smaller ships required to support such small scale infrastructure, b) any such potential source of supply is too distant from Mauritius, and c) small scale ships would not be economical over such long distances.

Another alternative to improve the competitiveness of LNG versus HFO would be to raise throughput to reduce the unit fee for the LNG terminal. The study has focussed on potential volumes for power generation and the transport, commercial and industrial sector. A sector that this study did not focus on is the marine transportation or LNG bunkering market. As a result of increasingly stringent emissions regulations for marine transportation in Emission Control Areas (MARPOL Annex VI), there is increasing interest in Europe and North America in LNG as an alternative fuel to bunker C and diesel oil for shipping. An increasing number of shipping companies are either ordering new LNG-fuelled ships or converting ships in their fleets. Interest in LNG bunkering is also increasing in Southeast Asia and the Middle East. Consequently, if the LNG bunkering market gains traction in the Indian Ocean and for routes close to Mauritius, LNG bunkering could serve as another potential market segment to increase LNG throughput and improve economies of scale. In the near term, bunker volumes would have to be about 0.45 MTPA for the Base Case volume scenario and about 0.3 MTPA for the High Case volume scenario to reach a break-even burner tip price of LNG versus HFO. Further studies would be required to assess the potential LNG bunkering market in Mauritius taking into account bunker demand in the domestic shipping sector, shipping routes and traffic and potential competition from major regional (South Africa) and super regional (Fujairah and Singapore) bunkering hubs.

6.6 Discussion and Recommendation

The LNG market is expected to be well supplied with LNG as new liquefaction projects are developed, sanctioned, and constructed to meet growing demand. Consequently, Mauritius should expect to be able to access supplies towards the end of the decade when the construction and commissioning of both the LNG terminal and the new 100 MW power plant are expected to be completed. Although the LNG requirements for Mauritius are relatively low under either the Base Case or High Case volume scenarios, Mauritius should still be able to procure LNG in the spot/Short-term market (for the Base Case), and potentially in a long-term contract for the High Case scenario. Because LNG suppliers tend to prefer to control the shipping of LNG and the volumes required are relatively small, LNG will most likely be purchased on a DES basis. This will allocate both the responsibility and the risks to procure and manage LNG shipping capacity to the LNG supplier.

While LNG requirements are relatively low, LNG prices and the cost of the LNG terminal infrastructure are expected to be relatively high. Consequently, it may be challenging to justify the use of LNG in the power sector if the delivered cost of regasified LNG (burner tip cost) is being compared to HFO as the next best fuel alternative. However, as demand growth, the LNG terminal infrastructure costs are spread over larger volumes and the spread between the burner tip cost of LNG and HFO improves over time. The price of LNG represents a significant portion of the burner tip cost of LNG and therefore, pricing dynamics in the market will have a significant impact on the affordability of LNG for Mauritius.

New potential sources of LNG are being developed in East Africa (Mozambique and Tanzania) and although that LNG is being targeted to be sold to large creditworthy markets (e.g. Japan) at prevailing global prices to justify the massive capital investments required, some of that output could be sold to smaller regional markets like Mauritius by Portfolio Suppliers participating in those projects. Pricing for that LNG is most likely to be based on global prices, however, a government-to-government agreement may result in discounted prices, although, to date, there are very few precedents for such discounted government-to-government LNG sales. For this project, the proportion of the burner tip cost that reflects the cost of the LNG infrastructure is very high (30% to 50% of the burner tip cost of LNG is attributed to the LNG infrastructure) because of the relatively low volume requirements. There may be opportunities to explore small scale LNG infrastructure alternatives to reduce the cost of the LNG imports, storage and regasification facilities if and when the regional market develops to support the loading of smaller volumes of LNG in small scale LNG ships, or the deliveries of smaller volumes of LNG from large scale LNG carriers calling on multiple smaller facilities.

Although increasing the volume requirements by promoting the use of regasified LNG in other sectors like transportation, industrial, commercial, and LNG bunkering can, overtime, improve economies of scale, the power sector is critical to serve as the anchor market for LNG as it drives short and medium term demand in Mauritius. If LNG is not economically feasible for the power sector and therefore not used in the power sector, it is very unlikely that LNG can be introduced in other sectors.

These conclusions only consider the potential economic feasibility of importing LNG as a substitute to HFO and do not address the environmental and social benefits resulting from using a cleaner burning fuel in power generation.

7. INTEGRATED IMPLEMENTATION PLAN & COST ESTIMATES

7.1 Introduction

This section presents a consolidated view on the implementation schedule and CAPEX spend (linked to the schedule) of the various aspects considered in the study, including the LNG supply chain, the LNG import infrastructure, the new 100MW LNG fired power plant and the conversion of the existing power stations (Fort Victoria and St. Louis). Although the gas demand for the planned new 4x15MW units at St. Louis has been included in the Base Case Demand Projection for this study, the CAPEX cost of these units (approx. 3.5Billion MUR) has not been included in the implementation plan or cost estimate as it is thought to be separate from the LNG study and planned to be implemented irrespective of the LNG study findings. The implementation schedule and cost of the transport sector are not included here and dealt with separately in Section 2; the transport sector can be developed separately, but is dependent on the cost and availability of NG on the island.

Various trade-offs were considered both from a technical and economical perspective in the respective sections dealing with each aspect and conclusions were drawn on the preferred options. This section will therefore not present the rationale in determining the preferred options again and the reader is referred to Sections 1, 3, 4 and 5 for detailed discussions on this. Exhibit 7-1 presents a high level summary of the preferred options for the LNG import infrastructure, New Power Plant and Conversion of old units.

Exhibit 7-1: Preferred options summary

LNG import infrastructure	New Power Plant	Conversion of old units
FSRU with dual berth type jetty (and related port and marine activities)	2x1 GTCC based on the LM6000 PF	Fort Victoria (6*15MW) and St. Louis (3*15MW)

7.2 Integrated Implementation Plan

The implementation plan considers high level durations as provided in Section 1.3.4 and 5.5.5 for the Power Plant and LNG Import Infrastructure respectively. The implementation plan has been developed to a level 2 and has been broken down by a standard Work Breakdown Structure and linked using logic based on experience of similar projects. Note that the aim of the Pre-Feasibility Study schedule is not to be an absolute schedule, but rather indicating the typical durations and sequence of events.

The follow key assumptions and highlights are noted:

- Durations used are from industry norms. No attempt has been made at this stage of the study to adjust for Mauritius specific conditions.
- Start date of schedule is the Contract signature of the Pre-feasibility study

- Gas to be provided 3 months before the commercial operation (CO).
- The Planned Completion date for the Mauritius LNG Project is the July 2019. This is a total of 45 months from first EPC Award.
- The precursors to EPC award are noted by key activity drivers such as the Environmental Impact Assessment, geotechnical and topographical surveys, which are scheduled for completion in July 2015. Priority must also be given to CEB's decision to proceed to FEED phase which will run for 6 months, with a planned completion date of April 2015. The tender and bid phase including finalization and contractor awards will run for a period of 8 months with the EPC Award scheduled for December 2015.
- The LNG supply chain phase to conduct market sounding and meet potential LNG suppliers will run for 24 months with a planned completion date of March 2018 for option 1 or December 2017 for option 2.
- The phase duration which covers Detailed Engineering, Procurement, Construction and Commissioning are as follows:

LNG Import Facilities	December 2015 to July 2018	32 months
100MW Power Plant	May 2016 to September 2018	29 months

- Also To be noted are key milestone dates for First Gas to be received by 1st June 2018, First Fire by 12th June 2018 and 100MW Power Plant Commercial operation 7 September 2018.

The implementation plant is presented in Exhibit 7-2.

Exhibit 7-2: Implementation Plan

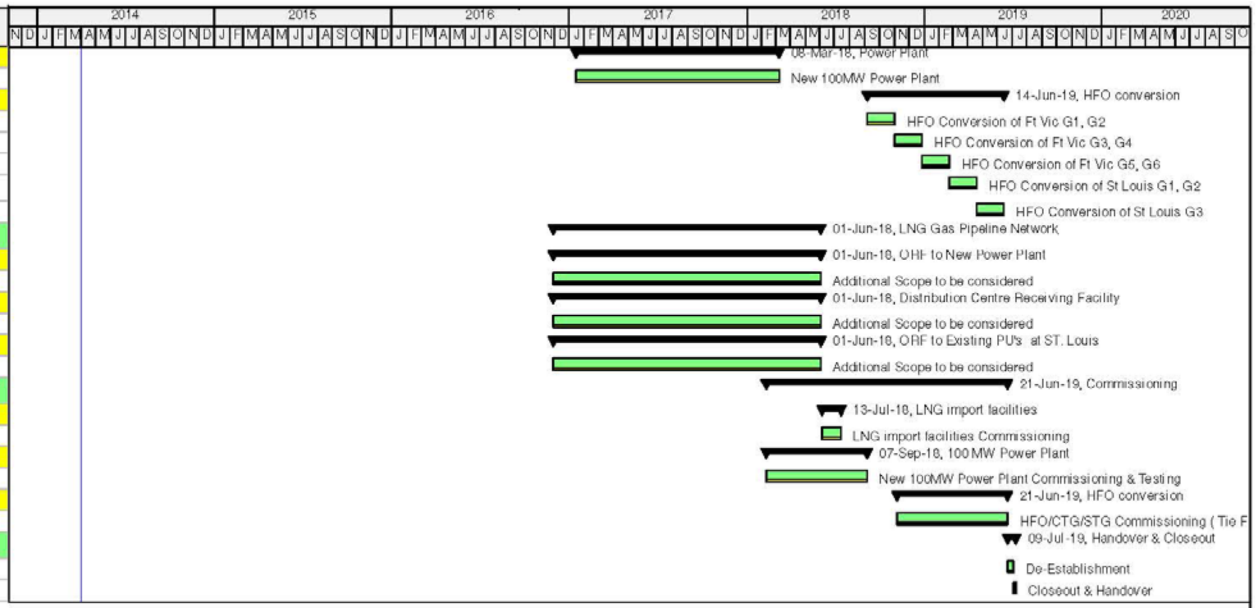
Activity ID	Activity Name	Original Duration	Start	Finish
Mauritius LNG Implementation Plan DRAFT		1472	18-Nov-13 A	09-Jul-19
Project Precursors		651	18-Nov-13 A	17-May-16
1.2PP.PREF.1000	PRE- FEAS/FEASIBILITY	122	18-Nov-13 A	06-May-14
1.2PP.PREF.1010	CEB decides to perform Feasibility/ Pre-FEED	25	06-May-14	10-Jun-14
2.PP.FEAS.1010	Feasibility/ Pre-FEED Completion	80	10-Jun-14	30-Sep-14
2.PP.FEAS.1020	CEB decides to perform FEED	25	30-Sep-14	04-Nov-14*
2.PP.FEAS.1030	FEED and SOW for EPC	120	04-Nov-14	21-Apr-15
2.PP.FEAS.1040	Floating of EPC tenders, receiving EPC Contractors bids	80	21-Apr-15	11-Aug-15
2.PP.FEAS.1050	Evaluation of EPC Bids and finalization of EPC contractors	80	11-Aug-15	01-Dec-15
2.PP.FEAS.1070	FSRU Contract Negotian (Client)	120	01-Dec-15	17-May-16
EPC Key Performance Indicators		940	01-Dec-15	09-Jul-19
Project Milestones		940	01-Dec-15	09-Jul-19
2.PP.FEAS.1060	EPC Contract Award	0	01-Dec-15	
KPI.1360	Project Planned Contractual Finish	0		09-Jul-19
LNG import facilities		460	26-Aug-16	01-Jun-18
KPI.1300	LNG Facilities Construction Start	0	26-Aug-16	
KPI.1310	LNG Facilities Construction Complete	0		08-May-18
KPI.1340	LNG Ready for First Gas	0		01-Jun-18*
Power Plant		431	13-Jan-17	07-Sep-18
KPI.1333	Power Plant Construction Start	0	13-Jan-17	
KPI.1334	First Fire	0		12-Jun-18
KPI.1335	New 100MW Power Plant Commercial Operation	0		07-Sep-18
HFO conversion		200	07-Sep-18	14-Jun-19
KPI.1320	HFO Conversion Start	0	07-Sep-18	
KPI.1330	HFO Conversion Complete	0		14-Jun-19
Project Management		1398	26-Feb-14	05-Jul-19
PM.1000	Project Management & Project Support Services	1398	26-Feb-14	05-Jul-19
Surveys & Investigation		280	10-Jun-14	07-Jul-15
EIA.1000	EIA & Authorty Approvals	280	10-Jun-14	07-Jul-15
GEO.1000	Geotechnical Survey	129	10-Jun-14	08-Dec-14
GEO.1010	Topographical Survey	129	10-Jun-14	08-Dec-14
MET.1000	METOCEAN Studies	258	10-Jun-14	05-Jun-15
Detailed Engineering		313	01-Dec-15	09-Feb-17
Power Plant		194	16-May-16	09-Feb-17
A1129	Power Plant EPC NTP	0	16-May-16*	
A1130	Detailed Engineering for New 100MW Power Plant	194	16-May-16	09-Feb-17
LNG import facilities		194	01-Dec-15	26-Aug-16
A1110	Detailed Engineering for LNG Import Facilities	194	01-Dec-15	26-Aug-16
Procurement		644	11-Mar-16	29-Aug-18
LNG import facilities		442	26-Aug-16	08-May-18
A1000	Procurement of FSRU & Delivery on site (Assume conversion)	442	26-Aug-16	08-May-18
A1010	Procurement of Marine Loading Arms	442	26-Aug-16	08-May-18
100 MW Power Plant		430	16-May-16	05-Jan-18
A1280	Procurement of CTG/STG	430	16-May-16*	05-Jan-18
HFO conversion		150	01-Feb-18	29-Aug-18
A1120	Procurement of HFO Conversion Parts	150	01-Feb-18*	29-Aug-18
LNG Supply Chain (Option 1)		516	11-Mar-16	05-Mar-18
A1140	Conduct Market Sounding & Meet Potential LNG Suppliers	65	11-Mar-16	10-Jun-16
A1150	Execute Master Sale Agreements with Potential LNG Suppliers	194	10-Jun-16	08-Mar-17
A1160	Conduct Tender for Commercial Spot Cargoes	65	07-Jun-17	05-Sep-17
A1170	Conduct Tender for Commissioning Cargo	65	07-Jun-17	05-Sep-17
A1180	Confirm Delivery Windows for Commissioning Cargo	129	07-Jun-17	04-Dec-17
A1190	Confirm Delivery Dates & Volumes for 1st Commercial Spot Cargo	0		05-Mar-18
LNG Supply Chain (Option 2)		452	11-Mar-16	04-Dec-17
A1200	Conduct Market Sounding & Meet Potential LNG Suppliers	65	11-Mar-16	10-Jun-16
A1210	Conduct Tender for Commercial Spot Cargoes (including SPA negoti	258	10-Jun-16	06-Jun-17
A1220	Conduct Tender for Commissioning Cargo	65	07-Jun-17	05-Sep-17
A1230	Confirm Delivery Windows for Commissioning Cargo	129	07-Jun-17	04-Dec-17
A1240	Conduct Commercial Cargo Scheduling Process with Selected Supp	65	07-Jun-17	05-Sep-17
Construction		730	26-Aug-16	14-Jun-19
LNG import facilities		460	26-Aug-16	01-Jun-18
CON.LNG.1010	Jetty Pipeline, ORF, Mechanical Construction Period	442	26-Aug-16	08-May-18
CON.LNG.1020	FSRU Functional	19	08-May-18*	01-Jun-18

Primary Baseline | Remaining Work
Actual Work | Critical Remaining Work

WorleyParsons
resources & energy

Date	Revision	Checked	Approved
04-Aug-14		Mario Patel	

Activity ID	Activity Name	Original Duration	Start	Finish
Power Plant		300	13-Jan-17	08-Mar-18
CON.POW.1000	New 100MW Power Plant	300	13-Jan-17*	08-Mar-18
HFO conversion		200	07-Sep-18	14-Jun-19
CON.HFO.1000	HFO Conversion of Ft Vic G1, G2	40	07-Sep-18	02-Nov-18
CON.HFO.1010	HFO Conversion of Ft Vic G3, G4	40	02-Nov-18	28-Dec-18
CON.HFO.1020	HFO Conversion of Ft Vic G5, G6	40	28-Dec-18	22-Feb-19
CON.HFO.1030	HFO Conversion of St Louis G1, G2	40	22-Feb-19	19-Apr-19
CON.HFO.1040	HFO Conversion of St Louis G3	40	19-Apr-19	14-Jun-19
LNG Gas Pipeline Network		395	28-Nov-16	01-Jun-18
ORF to New Power Plant		395	28-Nov-16	01-Jun-18
A1250	Additional Scope to be considered	395	28-Nov-16	01-Jun-18
Distribution Centre Receiving Facility		395	28-Nov-16	01-Jun-18
A1260	Additional Scope to be considered	395	28-Nov-16	01-Jun-18
ORF to Existing PU's at ST. Louis		395	28-Nov-16	01-Jun-18
A1270	Additional Scope to be considered	395	28-Nov-16	01-Jun-18
Commissioning		356	09-Feb-18	21-Jun-19
LNG import facilities		30	04-Jun-18	13-Jul-18
ZFCOMM.1010	LNG import facilities Commissioning	30	04-Jun-18	13-Jul-18
100 MW Power Plant		151	09-Feb-18	07-Sep-18
A1290	New 100MW Power Plant Commissioning & Testing	151	09-Feb-18	07-Sep-18
HFO conversion		162	07-Nov-18	21-Jun-19
A1300	HFO/CTG/STG Commissioning (Tie FF HFO)14040	162	07-Nov-18	21-Jun-19
Handover & Closeout		12	21-Jun-19	09-Jul-19
A1070	De-Establishment	10	21-Jun-19	05-Jul-19
A1080	Closeout & Handover	2	05-Jul-19	09-Jul-19



Primary Baseline	Remaining Work	WorleyParsons resources & energy
Actual Work	Critical Remaining Work	

Date	Revision	Checked	Approved
04-Aug-14		Mario Patel	

7.3 Implementation Capital Cost Estimate

The Capital cost estimate is developed based on the timelines as detailed on the Implementation Plan in previous section. The CAPEX estimate was used as input for the Section 8 – Economic and Financial Modelling. Main input to the model is the CAPEX estimates as provided for each aspect of the study and described in previous sections. The power plant estimates were developed by utilization of in-house data, Thermoflow PEACE software and supplemented by OEM supplied information. The LNG import infrastructure CAPEX has been derived from in-house data and previous experience with projects of similar nature. This CAPEX estimate is not a definitive control estimate, but representative of accuracy matching this phase of the study.

7.3.1 Estimate Class and Accuracy

The estimate is defined as being a Class 1 (order-of-magnitude) type capital cost estimate with an expected estimate accuracy <+/- 50%±50%[18] (before contingency), requiring a contingency range of 15 – 25%. A Project Contingency factor of 20% has been selected for this estimate.

7.3.2 Basis of Estimate

7.3.2.1 General Financial

The capital cost estimate amounts have been prepared in United States Dollars (USD) aligned to first quarter 2014 base values and median headline exchange rates and exclude currency, commodity, resource, industry supply-demand pull, fluctuation or escalation / inflation during the development of the project (refer Section 8 – Economic and Financial Modelling).

7.3.2.2 LNG Import Terminal

The capital cost estimate is based on Option 1 – Near-shore 178,000m^3 Floating Storage Regasification Unit (FSRU) with a jetty and 1MTPA subsea gas pipeline feeding an Onshore

[18] The +/- 50% estimate is fitting for the Pre-feasibility (Identify) stage of the project and as per CEB contract request. For this phase, the purpose of the cost estimate would be threefold: (1) To identify the potential value of the opportunity and its alignment with the overall business strategy, (2) To provide preliminary comparison of alternatives and (3) To access funding for pre-development, leading to the next project stage, "Feasibility".
For a Feasibility study (Evaluate phase), the purpose of the outcome can be defined as follows: To determine and compare the economic feasibility of Project options leading to concept selection & to determine the degree of cost commitment needed for subsequent phases as well as the determination of the approval to proceed to the (Define) stage. Normally, for the Evaluate Phase, the accuracy level improves to <+/- 30%. This is however only achieved by more study in the preferred possible options.

Receiving Facility (ORF) located at the Les Grandes Salines site as described in more detail in Section 3 and Section 5 of this report with specific CAPEX discussion in Section 5.5.1.

It has been assumed that the engineering and development of the entire LNG import facility will be implemented under a typical engineering, procurement and construction management (EPC) model and the FSRU will be procured under a long-term leasing arrangement requiring no initial capital investment or leasing cash deposits.

No dredging is indicated for the selected location of the ship access channel to the jetty and FSRU and normal seabed and ground conditions have been assumed within the direct capital cost estimates. Insufficient data exists at this time to conduct a quantified risk assessment of any adverse circumstances.

The developed capital cost estimate includes all anticipated costs for LNG infrastructure including materials, installation labour, professional services (Engineering, CM, and Start-up), and contingency within the plant boundary.

The LNG cost estimate basis and clarifications are presented below:

- The cost estimate includes the LNG import Jetty and the necessary unloading equipment on it such as Marine Loading Arms and the utilities
- Breasting and Mooring Dolphins for the FSRU and LNGC
- The HP Arm to transfer NG to Jetty
- Sub-sea pipeline
- On-shore Receiving Facilities including Pressure Let Down Station & Gas Metering
- The estimate is presented as overnight costs in first quarter 2014 US dollars. Escalation to period of performance is excluded.
- The estimate is based on an Engineering/Procurement/Construction (EPC) approach.
- The estimate is prepared on a US Gulf Coast (USGC) basis.
- The Jetty is assumed to be on Piles
- The site is assumed to be free from hazardous and/or contaminated materials.
- The site is assumed to be free of archeological artifacts.

Exclusions are:

- All taxes and duties with the exception of payroll taxes.
- Natural gas pipeline costs from the LNG terminal to the plant boundary
- Any adverse ground conditions that would unduly increase the foundation costs.
- Owner's costs, including interest during construction

Owner's costs are excluded from the estimate. Representative Owner's costs include, but are not limited to, the following:

- Project Development Costs
  - Permits & Licensing
  - Land Acquisition / Rights of Way Costs
  - Improvements to existing roads or infrastructure

- Owner's Engineering / Project & Construction Management Staff
- Plant Operators during startup
- Electricity, Fuel and Reagent consumed during startup
- Initial Fuel & Reagent Inventory and Operating Spare Parts
- Financing Costs

7.3.2.3 New 100MW GTCC Power Station

The capital cost estimate of the new 100 MW GTCC Power Station is based on Option 1 (see Section 1.3), a 2x1 GTCC based on the LM6000 PF as described in more detail in Section 1.3 of this report, and the plant design basis for costing is summarized below.

100 MW GTCC Plant Design Summary

- Two (2) LM6000PF aeroderivative combustion turbines, single fuel (NG) fired
- Two (2) bypass stacks to facilitate simple cycle operation
- Two (2) HRSG unfired, 2 Pressure levels, no SCR
- One (1) Non-reheat Steam Turbine Generator (STG), 50 bar, 445°C throttle steam
- Cycle Heat Rejection: Once through Seawater Cooling
- Two (2) Continuous Emissions Monitoring Systems (CEMS)
- Three (3) Generator Step-up Transformers (GSU)
- Water Treatment Facility
- Buildings include those for STG, administration/control room, warehouse/maintenance shop, and water treatment)

The capital cost estimate developed for this implementation plan is based on the Thermoflow GTPRO/GTMASTER and PEACE software. The GTPRO/GTMASTER software is used to design the GTCC configuration, develop heat & mass balances, auxiliary load estimates, and system performance, and size the major equipment. The PEACE (Plant Engineering and Cost Estimating) utilizes the GTPRO/GTMASTER configuration and equipment sizing to develop costs for equipment, material, labor, professional services, and project contingency. The Thermoflow software has many user defined inputs and options that allow the analyst to set project specific assumptions, and design criteria.

The PEACE software includes a performance and cost database for the major gas turbine models, as well as a cost database and costing algorithms for other equipment. The PEACE performance data library and cost database are routinely updated. The PEACE model is widely used in the industry for preliminary cost estimation and for comparing relative costs between various power generation options using similar technology and performing preliminary economic analyses.

The developed capital cost estimate includes all anticipated costs for Power-related equipment and materials, installation labor, professional services (Engineering, CM, and Start-up), and contingency within the plant boundary.

The New power plant cost estimate basis and clarifications are presented below:

- The cost estimate was developed with the Thermoflow PEACE cost estimating software.
- Equipment pricing for the combustion turbines reflects outdoor installation.
- The steam turbine pricing reflects indoor installation.
- The estimate is presented as overnight costs in first quarter 2014 US dollars. Escalation to period of performance is excluded.
- The estimate is based on an Engineering/Procurement/Construction (EPC) approach.
- The estimate is prepared on a US Gulf Coast (USGC) basis.
- An allowance of 10 million USD has been made to allow for the once through cooling intake and outfall circulating water system. With contingency and soft costs, this accounts for approximately 12 million USD.
- The site is assumed to be free from above ground or below ground obstructions.
- The site is assumed to be free from hazardous and/or contaminated materials.
- The site is assumed to be free of archeological artifacts.

Exclusions are:

- All taxes and duties with the exception of payroll taxes.
- Switchyard and transmission line (Cost scope terminates at the HV side of GSU)
- Natural gas pipeline costs from the LNG terminal to the plant boundary
- Any adverse ground conditions that would unduly increase the foundation costs.
- Black start capability
- Owner's costs, including interest during construction

Owner's costs are excluded from the estimate. Representative Owner's costs include, but are not limited to, the following:

- Project Development Costs
    - Permits & Licensing
    - Land Acquisition / Rights of Way Costs
    - Improvements to existing roads or infrastructure
- Owner's Engineering / Project & Construction Management Staff
- Plant Operators during startup
- Electricity, Fuel and Reagent consumed during startup
- Initial Fuel & Reagent Inventory and Operating Spare Parts
- Financing Costs

It has been assumed that the feasibility and front-end engineering (FEED) scoping of the project will develop a full engineering, procurement and construction (EPC) contract to secure the entire power station development on a progressive lump sum turnkey (LSTK) price basis.

No capital costs have been included for connection to the national power grid as it is assumed CEB will have inherent capacity and specialist knowledge of the grid infrastructure to conduct this work outside of the envisaged EPC contract for the power station.

The high level cost summary for the 100 MW GTCC power Plant option is presented in Exhibit 7-3.

Exhibit 7-3: 100 MW GTCC Project Capital Cost

Project Cost Summary		Estimated Cost (USD,000)	Units
I.	Specialized Equipment	62,621	USD
II.	Other Equipment	2,745	USD
III.	Civil	7,921	USD
IV.	Mechanical	9,057	USD
V.	Electrical assembly and Wiring	2,349	USD
VI.	Buildings and Structures	1,741	USD
VII.	Engineering and Plant Startup	6,752	USD
	a. Engineering	5,861	USD
	b. Start-up	891	USD
VIII.	Allowance for intake structure	10,000	USD
Subtotal – Contractors Internal Cost		**103,186**	**USD**
IX.	Contractors soft and miscellaneous costs	23,806	USD
	a. Contingency	6,264	USD
	b. Fee & Others	17,542	USD
EPC Contractor's Overnight Price		**126,991**	**USD**
Net Plant Output		**97.9**	**MW**
Price per kW – Contractor's		**1,297**	**USD per kW**

Notes: Currency basis, USD, first quarter 2014

7.3.2.4 HFO Conversions at Fort Victoria and Port Louis

The capital cost estimate is based on the conversion of 6 x 15MW (rated) existing heavy fuel oil (HFO) power generation units at Fort Victoria and 3 x 13.8MW (rated) existing heavy fuel oil (HFO) power generation units at Port Louis. The capital cost estimates are based on communications with the original equipment manufacturers' (OEM's), and cost are based on recent conversion experience in Africa.

All the modifications will be done in-situ on the basis that components do not require to be sent back to the OEM workshop/factory. The capital cost estimate includes all necessary plant modifications for the conversion, including scope outside of the engines such as addition of gas meters and regulators, gas piping from metering stations to termination points near the reciprocating engines, vent rupture disks, exhaust gas ventilating units, modification of electrical and control systems, etc. Additional details of the conversions can be found in Section 1.2.

Also note that LNG is regassed to NG at the LNG Terminal and transported via sub-sea pipeline to ORF at Les Grandes Salines. From there it is transported by On-shore pipeline to the existing Power Plant. It was discussed at the meetings with CEB that it may be possible to use the existing HFO right of way as an option. Given the pre-feasibility study order of magnitude (+/-50%) cost estimates, the volume of gas required and the relatively short distances from the ORF, the cost for the onshore pipeline is not shown separately, but assumed to be include in the LNG infrastructure CAPEX figures. In further study, this can be broken out in more detail.

It has been assumed that the feasibility and front-end engineering (FEED) scoping of the project, which will be done closely with existing CEB plant operations staff, will develop a full engineering, procurement and construction (EPC) contract to secure the power unit conversions development on a progressive lump sum turnkey (LSTK) price basis.

7.3.2.5 Feasibility, FEED and EPCM Costs

These costs have been factored from the direct capital costs on the basis of the high-level contracting strategy set out above, requiring considerable engineering scoping effort in establishing a bankable feasibility study and scoping the determinate elements of the project for contracting on an EPC basis. The estimated feasibility study costs include surveys and investigations (geotechnical, bathymetry, metocean, etc.) required as input data into the feasibility and EPC scoping phase.

7.3.3 CAPEX Estimate Results

The results for the CAPEX estimation are given in summary format in Exhibit 7-4.

Exhibit 7-4: CAPEX summary

WBS LEVEL 1 (Value- Chain)	WBS LEVEL 2 (Process / Area / Element)	Amount
LNG IMPORT FACILITY		
	JETTY STRUCTURE	$52,421,509
	JETTY TOPSIDES EQUIPMENT	$6,900,000
	JETTY TOPSIDES CONSTRUCTION	$23,184,000
	FSRU (Leased)	$0
	EXPORT GAS PIPELINE	$14,421,509
	ORF EQUIPMENT	$9,000,000
	ORF CONSTRUCTION	$3,001,018
	O&U (Offsites & Utilites)	$22,621,295

WBS LEVEL 1 (Value- Chain)	WBS LEVEL 2 (Process / Area / Element)	Amount
POWER PLANTS		
	NEW POWER PLANT (100MW)	$126,990,734
	HFO CONVERSION FT VICTORIA (6x15MW)	$31,500,000
	HFO CONVERSION ST LOUIS (3x13.8MW)	$14,490,000
EPCM		
	FEASIBILITY STUDY - LNG TERMINAL	$989,383
	FEASIBILITY STUDY - NEW 100MW PS	$266,681
	FEASIBILITY STUDY - HFO PS CONVERSIONS	$308,133
	FEED - LNG TERMINAL	$14,289,543
	FEED - NEW 100MW PS	$1,587,384
	FEED - HFO PS CONVERSIONS	$919,800
	IMPLEMENTATION - LNG	$2,935,000
	IMPLEMENTATION - NEW 100MW PS	$1,593,000
	IMPLEMENTATION - HFO CONVERSION	$1,722,000
OWNERS' COSTS		Excluded
SUBTOTAL (excluding Contingency)		$329,140,988
PROJECT CONTINGENCY @ 20%		$65,828,198
TOTAL CAPEX (including Contingency)		**$394,969,186**

The Capex spend curves, given the presented schedule is given in Exhibit 8-7 and Exhibit 8-23 for the LNG import infrastructure and 100MW Power Plant respectively.

Estimates for the O&M costs are provided in Exhibit 8-8 and Exhibit 8-25 for the LNG import infrastructure and 100MW Power Plant respectively.

8. ECONOMIC AND FINANCIAL MODELLING

8.1 Introduction

The goal for this deliverable is to create two financial models that integrates the economics of the new greenfield combined cycle gas turbine plant with the economics of the development, construction and operations of the LNG import infrastructure (LNG Import Terminal that will handle the unloading, storage, regasification and redelivery of LNG), and the acquisition of LNG supplies. To accomplish the goal the Consultant developed two excel-based economic cash flow models that incorporate the two major components namely:

8.1.1 The LNG Import Terminal and LNG Procurement Project Finance Model

This model focuses on modelling the economics of developing, constructing and operating a greenfield LNG Import Terminal. One of its outputs is a tariff consisting of a capacity reservation charge and a throughput charge. In addition the model calculates a tariff per MMBtu that is sufficient to cover the entire cost of the plant plus return to the owners. The proposed tariff is calculated for several LNG throughput scenarios that will reflect the analysis conducted to address the various potential sources of LNG demand and off take scenarios. The model integrate various LNG pricing scenarios (assuming that LNG is priced on a Delivered Ex-Ship basis to the island of Mauritius by the LNG supplier(s) as this is the most likely LNG purchase scenario applicable to a new market like the island of Mauritius in the context of current LNG market dynamics) and the tariff for the LNG Import Terminal to establish various "burner tip" cost of fuel scenarios to be used as inputs for the Newbuild Power Generation Project Finance Model section and to use in the desk top analysis of the transport sector off take.

8.1.2 The Newbuild Power Generation Project Finance Model

This model focuses on modelling the economics of developing, constructing and operating the greenfield CCGT power plant. Its output includes a tariff consisting of a capacity reservation charge and commodity charge. The capacity reservation charge is designed to cover the fixed cost, including debt service, and return for the shareholder while the commodity charge cover the cost of variable operating cost, of which a large proportion is the fuel cost. In addition the model calculates a tariff per kWh that is sufficient to cover the entire cost of construction and operating of the plant and fuel cost plus return to the owners. The projected cost of power to the grid is based on the power plant tariff and cost of fuel for various scenarios resulting from the LNG Import Terminal and LNG Procurement. The tariff calculated is at the Power Station gate and does not include any provision for network related losses.

Both financial models are assuming a typical project finance debt to equity structure and are set up as separate stand-alone Project Vehicles.

8.2 LNG Import Terminal Model

8.2.1 Overview

Set out below are the key concepts around which the model is built. The model is USD based and all of the Annual Financial Statements are presented as such (in USD' thousands).

The model is built on a "Tolling" concept, meaning that the plant doesn't own the product at any stage and just re-gasifies it for the client. In practical terms, this means that the plant doesn't have the working capital requirement of purchasing raw material, nor does the plant pay for losses incurred during the re-gasification process (the plant does pay for the gas it consumes in the heating process). Further, in order to smooth the tariffs, the plant generates revenue on a capacity charge basis, meaning revenue is earned for processing capacity installed and available, regardless of actual throughput. The principle is that the full cost and return need to be recovered from the off takers regardless of the actual throughput. The implication of this approach is that effective regasification tariffs per MMBtu will be relatively high during the early years while volumes are still modest. Unless the Terminal receives Government support by way of a subsidy to make up the revenue requirement, there is no real alternative to this approach.

8.2.2 Base Case Assumptions

Detailed below are the various categories of assumptions and the Base Case values applied.

8.2.2.1 Timing assumptions

These assumptions deal with the construction schedule, delays and project life. A construction schedule of 17 months is assumed for this study and a plant operating life of 25 years. The base case assumptions are presented below.

Exhibit 8-1: Base Case Timing Assumptions

	Start	Interval	Duration (excludes pre construction)	End
Construction	Sep-16	Months	23 Mth(s)	Jul-18
Delay	Aug-18	Months	0 Mth(s)	Jul-18
Pre-Ops	Aug-18	Months	0 Mth(s)	Jul-18
Operations	Aug-18	Semi-Annual	25.00 Yr(s)	Jul-43

8.2.2.2 Macro-Economic assumptions

The base case assumptions are specified below. These assumptions have been sourced from various available sources, including Statistics Mauritius and State Bank of Mauritius.

Exhibit 8-2 - Base Case Inflation Assumptions

Index Name	Unit	2015	2016	2017	2018	2019	2020
CPI	% p.a	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

Exhibit 8-3 - Base Case Prime Rate Assumption

Prime Rate	Unit	2015	2016	2017	2018	2019	2020
Applied	% p.a	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%

Exhibit 8-4 – Base Case Interest on Positive Cash Balance

	Unit	2015	2016	2017	2018	2019	2020
Rate Earned	% p.a	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%

Exhibit 8-5 - Base Case Ex. Rates

Currency Name	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023
MUR	USD:MUR	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
EUR	USD:EUR	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40

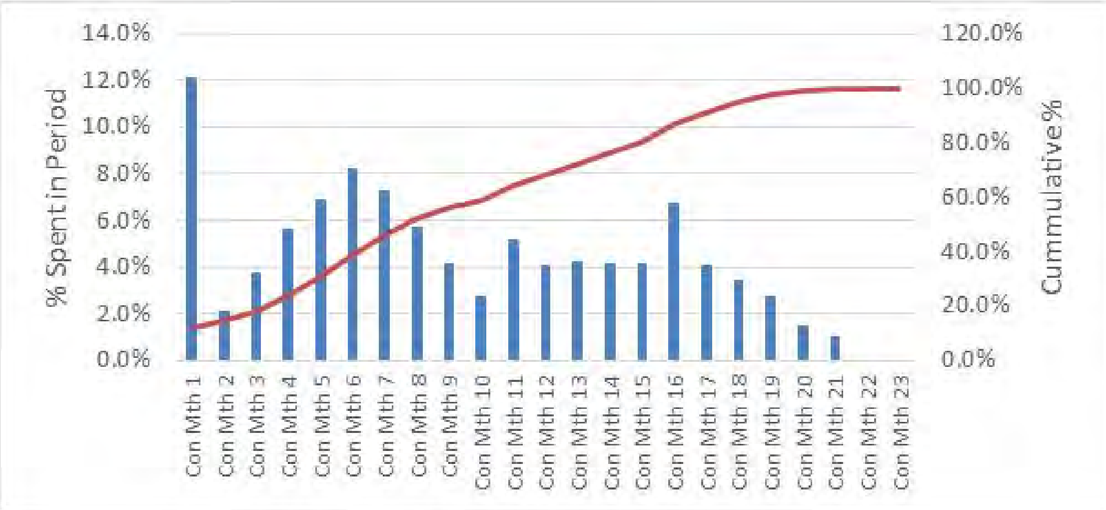
8.2.2.3 Capital Expenditure

Capital expenditure has been estimated at USD 179.7m (which includes cost recovery for several studies and a 20% contingency), excluding VAT which has been added separately, at a rate of 15%. VAT paid during the construction phase is assumed to be received back after 3 months. Expenditure has been spread over 21 months.

Exhibit 8-6 – Capital Expenditure Line Items

Item	Currency	Amount	Contingency	VAT
JETTY STRUCTURE	USD	52 421	20%	Yes
JETTY TOPSIDES EQUIPMENT	USD	6 900	20%	Yes
JETTY TOPSIDES CONSTRUCTION	USD	23 184	20%	Yes
EXPORT GAS SPIPELINE	USD	14 421	20%	Yes
ORF EQUIPMENT	USD	9 000	20%	Yes
ORF CONSTRUCTION	USD	3 001	20%	Yes
ORF MISC	USD	22 621	20%	Yes
FEASIBILITY STUDY - LNG TERMINAL	USD	989	20%	Yes
FEED - LNG TERMINAL	USD	14 289	20%	Yes
IMPLEMENTATION - LNG	USD	2 935	20%	Yes

Exhibit 8-7: % Spend S-curve



8.2.2.4 Operating and Maintenance Costs

Set out below are the base case assumptions on the various operating cost items anticipated. The nature of the facility dictates a very high percentage of the expenditure as being fixed. These items include the charter for the FSRU and the crew cost amongst others. The cost towards Fuel consumption for FSRU varies as function of regas capacity. It is estimated based on electric power of LNG Booster pump, Sea Water pump and BOG compressor motors to be 4000 kW for 0.3 MTPA capacity and 5000 kW for 1 MTPA capacity. (refer Section 5.5.2)

Exhibit 8-8 - Operating Expenditure

Item	Index	Currency	Year 1 USD '000
FSRU Charter Cost	No Inflation	USD	45 625
Crew cost at Jetty & ORF	CPI	USD	600
Maintenance & Spares	CPI	USD	1 810
Own Consumption	CPI	USD	19
Crew cost at FSRU	CPI	USD	8 030
Project Management + Insurance	No Inflation	USD	1 784
Electricity (FSRU, Jetty, ORF)	CPI	USD	4800 (note 1)

Note 1: Electricity Consumption: 4.8 MM USD for 0.3 MTPA Capacity and 6 MMUSD for 1.0MTPA capacity.

8.2.2.5 Throughput Ramp-up

The Base Case assumes the plant will be able to operate at full capacity from operations start and will be able to process 1 million tons per year. The maximum throughput achieved over the evaluation lifetime of the plant on a high growth scenario is [589 000 ton] suggesting the Terminal is sized to comfortably process the anticipated LNG requirements.

8.2.2.6 Off take and Sales Price

Exhibit 8-9 displays the main deal terms including the escalation index as per the macro-economic assumption and the percentage escalated. The model assumes an agreement is reached such that the off-taker pays a rate per processing capacity available (as opposed to actually process). This is in order to minimise the down side effects of lower throughput in the early years when demand is still adjusting. In determining the price per ton of capacity available, the model allows the user to define the desired Internal Rate of Return, and the model will adjust the price accordingly. This rate has been set at 20%, which is considered adequate for this asset class.

Exhibit 8-9 - Base Case Off-Take Assumptions

	Value
Off taker	Power Plant
Start (Assume 2 months commissioning supply)	01-Aug-18
Duration	25
End	31-Aug-43
Escalation	100%
Index	CPI
Escalation start	01-Sep-16

8.2.2.7 Taxation and Depreciation

Exhibit 8-10 displays the categories identified and applied in the model. These same categories have been applied for tax purposes, although these may be depreciated on a different basis for tax purposes. These are displayed in Exhibit 8-11. Corporate tax rate has been assumed at the standard Mauritian rate of 15%. Tax losses are assumed not to expire, and are set at 30 years, which is beyond the plant operating life. No Dividend Withholding Tax has been assumed.

Exhibit 8-10 - Accounting Asset Classes

						Reducing Balance	
	Financial Category	Method Applied	Depreciate Over	% p.a	% p.pd	Multiplier	% p.pd
1	Major Equipment	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
2	Balance of Plant	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
3	Grid / Step up	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
4	Spare4	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%

5	Spare5	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%
6	Intangible	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%
7	Non Tax Deductible	SL	3.00 Yr(s)	33%	17%	1.50x	25.00%
8	Deductible Financing Fees	SL	2.00 Yr(s)	50%	25%	1.50x	37.50%
9	IDC/Insurance	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%

Exhibit 8-11 - Tax Asset Classes

						Reducing Balance	
	Financial Category	Method Applied	Depreciate Over	% p.a	% p.pd	Multiplier	% p.pd
1	Major Equipment	50/30/20	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
2	Balance of Plant	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
3	Step up	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
4	Spare4	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%
5	Spare5	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%
6	Intangible	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%
7	Non Tax Deductible						
8	Deductible Financing Fees	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
9	IDC/Insurance						

8.2.2.8 Funding assumptions

Detailed below are the main funding assumptions. These are the anticipated market rates or practices for a project of this nature:

- Debt: Equity is assumed at 60:40.
- Debt tenure is assumed to be 10 years.
- Upfront fees (both underwriting and facility) have been assumed at 1.5% of facility amount.
- Commitment fees have been assumed at 0.6% of amount available but not drawn.
- Agency fees have been assumed at USD 55-45 '000, p.a.
- Fixed total repayment (annuity) is assumed.
- All in interest rate (annual) of 7.68%-7.98%.
- Debt Service Reserve account equal to six months of debt service has been assumed, and is pre funded at the start of operations.

The debt covenants assumed are detailed below:

Exhibit 8-12 - Base Case Covenants

Base	Base Case
ICR	0.00x
Min. DSCR	1.30x
LLCR	1.30x
PLCR	1.30x
Ave. DSCR	1.40x

Equity is assumed to be contributed as 25% Pure Equity and 75% Shareholder Loans. Dividends pay-out method has been set at 100% of funds available, limited by accounting profit.

8.2.3 Base Case Results

Exhibit 8-13 details the results of the modelling preformed, under the base case scenario, to 2030. As can be seen the implied charge per MMbtu decreases with increased processing quantity. This effect flattens out as peak demand is reached (estimated in years 2031 onwards), thus increasing the cost per MMbtu (inflationary impact on price).

Exhibit 8-13 - Base Case Results

Calander Year	Annual Capacity Fees (USD '000)	Quantity LNG Processed (Ton '000 pa)	Capacity Charge (USD / Ton)	Capacity Charge (USD / Mmbtu)
2018	47 143	61	767	15.76
2019	95 935	127	753	15.46
2020	99 293	132	754	15.48
2021	102 768	135	762	15.66
2022	106 365	139	765	15.70
2023	110 088	143	770	15.81
2024	113 941	147	774	15.88
2025	117 929	151	779	16.00
2026	122 057	156	784	16.10
2027	126 329	161	787	16.16
2028	130 750	166	788	16.18
2029	135 326	169	801	16.44
2030	140 063	176	794	16.31

8.2.3.1 Sources and Application of funds

The project has a peak funding requirement of roughly USD 197.9m. This amount is applied mainly on construction costs (91%) and is funded through a 60%:40% split between debt and equity, respectively (Shareholder Loans treated as equity).

Exhibit 8-14: Sources and application of funds

Applications	USD '000	%
Total Construction Costs	179 713	91%
Senior Debt Facility IDC	6 791	3%
Senior 1 Fees	2 730	1%
DSRA/c Initial Funding	8 709	4%
VAT Net Uses	274	0%
Total	198 217	100%
Sources	**USD '000**	**%**
Senior Debt Facility	118 930	60%

Shareholder Loans	59 465	30.0%
Pure Equity	19 822	10.0%
Total	198 217	100%

8.2.3.2 Cash flow analysis

As expected, the single biggest drag on cash generated is the operating expenditure which consumes 55% of the revenue generated, followed by tax and debt service. Revenue generated is adjusted by the working capital requirements, set at 30 days for creditors and debtors.

These items, amongst others (as fully detailed in the model's financial statements) result in a cash flow to equity of USD 1 220 million over the 25 year period, representing 33% of the revenue generated by the project. This is considered to be a healthy percentage for a project of this type and offers good coverage ratios, as further detailed below. This contributes to the project's ability to raise funding.

8.2.3.3 Ratio Analysis

Table 13 displays the debt coverage ratios. As can be seen, while the minimal is obtained shortly after Commercial Operation Date, the overall average of the Debt Service Cover Ratio ("DSCR") and other ratios are well above the covenants levels and could offer greater comfort to potential lenders.

Exhibit 8-15 - Base Case Ratios

Metric	Min.	Min. Date	Avg./@ CoD
DSCR (1 Year(s) backward looking)	1.25	01-Aug-18	1.97
DSCR (3 Year(s) forward looking)	1.57	01-Jul-18	2.14
LLCR	1.93	01-Aug-18	1.93
PLCR	4.22	01-Aug-18	4.22

8.2.3.4 Break-even

Breakeven is analysed on several different cash flows, both nominal and real. It is noted that these cash flows are generated under the pricing assumption (such that equity IRR will equal 20%), as detailed above. Overall, the project displays short payback times for a project of this magnitude and type. This would indicate that it would be possible to lower return requirements and tariffs to improve the economics for the off takers if the plant owner is prepared to accept a lower return on investment.

Exhibit 8-16 - Base Case Payback

Payback	Real	Nominal
Project Ungeared	8.92 Yr(s)	7.92 Yr(s)
Project Geared	8.42 Yr(s)	7.42 Yr(s)
Equity	8.42 Yr(s)	7.42 Yr(s)

8.2.4 Base Case Sensitivity Analysis

Exhibit 8-17 details the main outputs of the sensitivity analysis performed, under which the following scenarios have been modelled:

- Capital cost: ±20%.
- Operating cost: ±20%.
- FSRU lease: USD 140/110 '000 per day.
- Interest rate: ±2%.
- Throughput: 35%, 65%, 85%.
- Oil Price: high, low, HHP.

Exhibit 8-17 – Sensitivity: Main Parameters

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Year 1 Production (Ton'000)	Year 1 Cap. Income	Year 1 Tariff (USD/ MMbtu)	Year 15 Tariff
FSRU	179 713	80 405	198 217	126	94 285	15.43	16.80
+20% Capex	215 656	81 071	237 835	126	101 475	16.60	18.09
-20% Capex	143 771	79 740	158 600	126	87 060	14.24	15.52
+20% Opex	179 713	96 486	198 217	126	106 333	17.40	18.95
-20 Opex	179 713	64 324	198 217	126	82 203	13.45	14.65
Interest 2% up	179 713	80 405	200 785	126	95 537	15.63	17.03
Interest 2% down	179 713	80 405	195 641	126	93 060	15.23	16.59
$140k per day Charter cost	179 713	86 274	198 217	126	99 092	16.21	17.66
$110k per day Charter cost	179 713	74 536	198 217	126	89 460	14.64	15.94
Low case 35% load factor	179 713	80 395	198 217	99	94 280	19.52	18.60
High case + 65% load factor	179 713	80 581	198 217	286	94 353	6.77	6.08
High case + 85% load factor	179 713	80 594	198 217	321	94 359	6.03	5.81
High Oil price	179 713	80 412	198 217	126	94 288	15.43	16.80
Low Oil price	179 713	80 389	198 217	126	94 278	15.42	16.80
Henry Hub price	179 713	80 375	198 217	126	94 277	15.42	16.80

It is noted that under the higher utilisation scenarios, the market reaches saturation before the plant reaches it full utilisation. Therefore, the processing is constrained to the market's ability to absorb the product processed.

8.2.5 Financial Model

It is noted that while care has been taken in constructing the financial model, it has not been independently audited. Appendix 3 details the model's annual financial statements ("AFS").

8.3 New Power Plant Model

8.3.1 Overview

Set out below are the key concepts around which the model is built. The model is USD based and all of the Annual Financial Statements are presented as such (in thousands).

The model is built on a "Merchant" concept, meaning that the plant sells its output (energy generated) at a tariff. The tariff produced by the model is an all-inclusive tariff and covers both operating expenditures as well as return on capital. It is noted that private market power plants would normally have a different tariff structure (potentially including fuel, capacity and energy charges separately), but this has not been modelled at this the PFS level, and is considered to be more appropriate for a BFS level when the PPA terms are more detailed and defined.

8.3.2 Base Case Assumptions

Detailed below are the various categories of assumptions and the Base Case assumptions applied.

8.3.2.1 Timing

These assumptions deal with construction schedule, delays and project life. The project assumes a construction period of 21 months and operating period of 25 years. The base case assumptions are presented below.

Exhibit 8-18 - Base Case Timing Assumptions

	Start	Interval	Duration (excluding pre construction)	End
Construction	Jan-17	Months	21 Mth(s)	Sep-18
Delay	Oct-18	Months	0 Mth(s)	Sep-18
Pre-Ops	Oct-18	Months	0 Mth(s)	Sep-18
Operations	Oct-18	Semi-Annual	25.00 Yr(s)	Sep-43

8.3.2.2 Macro-Economic

This section contains assumptions dealing with various indices including interest rates and inflation. The base case assumptions are specified below. These assumptions have been sourced from various sources, including Statistics Mauritius and State Bank of Mauritius.

Exhibit 8-19 - Base Case Inflation Assumptions

Index Name	Unit	2017	2018	2019	2020	2021	2022
CPI	% p.a	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

Exhibit 8-20 - Base Case Prime Rate Assumption

Prime Rate	Unit	2017	2018	2019	2020	2021	2022
Applied	% p.a	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%

Exhibit 8-21 – Base Case Interest on Positive Cash Balance

	Unit	2017	2018	2019	2020	2021	2022
Rate Earned	% p.a	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%

Exhibit 8-22 - Base Case Ex. Rates

Currency Name	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025
MUR	USD:MUR	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
EUR	USD:EUR	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40

8.3.2.3 Capital Expenditure

Capital expenditure has been estimated at USD 156.5m (which includes cost recovery for several studies and a contingency of 20%), excluding VAT which has been added separately, at a rate of 15%. VAT paid during the construction phase is assumed to be received back after 3 months. Expenditure has been spread over 21 months.

Exhibit 8-23 - Power Plant Capital Expenditure

Item	Currency	Amount	Contingency	VAT
Total plant EPC	USD	126 990	20%	Yes
FEASIBILITY STUDY - NEW 100MW PS	USD	266	20%	Yes
FEED - NEW 100MW PS	USD	1 587	20%	Yes
IMPLEMENTATION - NEW 100MW PS	USD	1 593	20%	Yes

Exhibit 8-24 - Spend Curve

8.3.2.4 Operating and Maintenance Costs

The plant has two types of costs. The fixed component comprised solely of the O&M contract, and variable cost, which account for fuel and terminal usage fees. These are detailed below and escalated according the indicated index.

Exhibit 8-25 - Power Plant Operating Costs

Item	Unit	Year 1	Avg. Cost
Operation & Maintenance Contract	USD '000	1 959	2 100
LNG import cost (SPA)	USD/ Mmbtu	14	22.8
Terminal usage fees (TUA)	USD/ Mmbtu	16	19.2
Water Requirement	USD/cbm	3	7.7
O&M (Maintenance, chemicals & consumables)	USD/ MWh	5	12.4

8.3.2.5 Throughput Ramp-up

The Base Case assumes the plant will operate at a 50% dispatch factor from operations start for the duration of the evaluation period. No ramp-up profile is assumed. In addition dispatch scenarios of 35%, 65% and 85% are considered.

8.3.2.6 Off take and Sales Price

The plant is assumed to have a guaranteed offtake of the full production yield, for the duration of the plant life. Table 23 displays the main deal terms including the escalation index as per the macro-economic assumption and the percentage escalated. In determining the price per kWh generated, the model allows the user to define the desired Internal Rate of Return, and the model will adjust the price accordingly.

Exhibit 8-26 - Base Case Off-Take Assumptions

	Value
Offtaker	Utility
Start	01-Oct-18
Duration	25.00 Yr(s)
End	31-Oct-43
Escalation	100%
Index	CPI
Escalation start	01-Jan-17

8.3.2.7 Taxation and Depreciation

Exhibit 8-27 displays the categories identified and applied in the model. These same categories have been applied for tax purposes, although these may be depreciated on a different basis for tax purposes. These are displayed in Exhibit 8-28. Corporate tax rate has been assumed at 15%. Tax losses are assumed not to expire, and are set at 30 years, which is beyond the plant operating life. No Dividend Withholding Tax has been assumed.

Exhibit 8-27 - Accounting Asset Classes

						Reducing Balance	
	Financial Category	**Method Applied**	**Depreciate Over**	**% p.a**	**% p.pd**	**Multiplier**	**% p.pd**
1	Major Equipment	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
2	Balance of Plant	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
3	Grid / Step up	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%
4	Spare4	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%
5	Spare5	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%
6	Intangible	SL	5.00 Yr(s)	20%	10%	1.50x	15.00%
7	Non Tax Deductible	SL	3.00 Yr(s)	33%	17%	1.50x	25.00%
8	Deductible Financing Fees	SL	2.00 Yr(s)	50%	25%	1.50x	37.50%
9	IDC/Insurance	SL	20.00 Yr(s)	5%	3%	1.50x	3.75%

Exhibit 8-28 - Tax Asset Classes

						Reducing Balance	
	Financial Category	**Method Applied**	**Depreciate Over**	**% p.a**	**% p.pd**	**Multiplier**	**% p.pd**
1	Major Equipment	50/30/20	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
2	Balance of Plant	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
3	Grid / Step up	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
4	Spare4	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%
5	Spare5	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%
6	Intangible	SL	5.00 Yr(s)	20.00%	10.00%	1.50x	15.00%

7	Non Tax Deductible						
8	Deductible Financing Fees	SL	20.00 Yr(s)	5.00%	2.50%	1.50x	3.75%
9	IDC/Insurance						

8.3.2.8 Funding assumptions

Detailed below are the main funding assumptions. These are the anticipated market rates or practices for a project of this nature:

- Debt: Equity is assumed at 60:40.
- Tenure is assumed to be 10 years, with a principal grace period of one year.
- Fixed total repayment (annuity) is assumed.
- All in interest rate (annual) of 7.68%-7.98%.
- Debt Service Reserve account equal to six months of debt service has been assumed, and is pre funded.

The debt covenants assumed are detailed below:

Exhibit 8-29 - Base Case Covenants

Base	Base Case
ICR	0.00x
Min. DSCR	1.30x
LLCR	1.30x
PLCR	1.30x
Ave. DSCR	1.40x

Equity is assumed to be contributed as 25% Pure Equity and 75% Shareholder Loans.

Dividends pay-out method has been set at 100% of funds available, limited by accounting profit.

8.3.3 Base Case Results

Detailed below are various aspects of the results including abbreviated cash flow. The base case tariff of USD 0.29/kWh or MUR 8.70/kWh has determined such that it would yield an equity IRR of 20%. As can be see this tariff creates a breach in the assumed debt covenants. It is assumed that this breach can be structured through adjusting the debt repayment profile.

Exhibit 8-30 - Base case Key Parameters

Case	Construction costs USD'000	Average Opex USD'000	Peak Funding USD'000	Ave Production p.a MWh	Year 1 Tariff (USD/kWh)	Tariff (MUR/kWh)	Minimum DSCR	Equity Nominal Payback
Base Case	156 523	126 353	177 276	403 488	0.29	8.67	1.21	7.25

The project can start repaying shareholders loans in year six of operations, which is considered reasonable for a project of this magnitude.

Exhibit 8-31 - Abbreviated Cash Flow

Item	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenue	-	-	117 186	121 305	125 045	129 087	132 789	137 101	142 009
OpEx	-	-	(94 370)	(96 124)	(98 146)	(98 249)	(101 967)	(104 218)	(106 916)
Net Adjustment	-	-	(1 656)	(157)	(125)	(276)	7	(162)	(148)
CapEx	(187 200)	(13 600)	-	-	-	-	-	-	-
Funding	187 200	13 600	4	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-
CFADS	(0)	-	21 165	25 025	26 774	30 563	30 829	32 722	34 945
Senior Debt Service	-	-	(15 533)	(15 547)	(15 534)	(15 534)	(15 534)	(15 543)	(15 535)
Debt Service Reserve Account	-	-	(14)	-	1	1	1	-	1
S/h Loan	-	-	(0)	(5 909)	(5 909)	(5 909)	(5 909)	(5 909)	(5 909)
Cashflow Available for Equity	(0)	-	5 617	3 568	5 332	9 120	9 386	11 269	13 501

8.3.3.1 Sources and Application of funds

Exhibit 8-32 - Power Plant Sources and Application of Funds

Applications	USD '000	%
Total Construction Costs	156 523	88%
Senior Debt Facility IDC	11 061	6%
Senior 1 Fees	1 928	1%
DSRA/c Initial Funding	7 759	4%
VAT Net Uses	4	0%
Total	177 276	100%
Sources	**USD '000**	**%**
Senior Debt Facility	106 366	60%
Shareholder Loans	53 183	30.0%
Pure Equity	17 728	10.0%
Total	177 276	100%

The project has a peak funding requirement of roughly USD 174.5m. This amount is applied mainly on construction costs (89%) and is funded through a 60%:40% split between debt and equity, respectively. Shareholders loans have been applied under a thin capitalisation assumption of 1:3.

8.3.3.2 Cash flow analysis

As expected, the single biggest drag on cash generated is the operating expenditure which consumes 70% of the revenue generated, followed by tax and debt service. Revenue generated is adjusted by the working capital requirements, set at 30 days for creditors and debtors. This investment is assumed to be fully recovered in the final period.

These items, amongst others (as fully detailed in the model's financial statements) result in a cash flow to equity of USD 1 276m over the 25 year period, representing 21% of the revenue generated by the project. This is considered to be a typical percentage for a project of this type and offers good coverage ratios, as further detailed below. This contributes to the project's ability to raise funding.

8.3.3.3 Ratio Analysis

Exhibit 8-33 displays the debt coverage ratios. As can be seen, while the minimal is obtained shortly after Commercial Operation Date, the overall average of the DSCR and other ratios are well above the covenants levels and could offer greater comfort to potential lenders. With appropriate structuring of the debt repayment profile, the desired cover ratios should be achievable.

Exhibit 8-33 - Base Case Ratios

Metric	Min.	Min. Date	Avg./@ CoD
DSCR (1 Year(s) backward looking)	1.21	Oct-18	1.94
DSCR (3 Year(s) forward looking)	1.57	Sep-18	3.23
LLCR	1.90	Oct-18	1.90
PLCR	4.00	Oct-18	4.00

8.3.3.4 Break-even

Breakeven is analysed on several different cash flows, both nominal and real. It is noted that these cash flows are generated under the pricing assumption, as detailed above. Overall, the project displays short payback times for a project of this magnitude and type.

Exhibit 8-34 - Base Case Ratios

Payback	Real	Nominal
Project Ungeared	8.25 Yr(s)	7.25 Yr(s)
Project Geared	8.25 Yr(s)	7.25 Yr(s)
Equity	8.25 Yr(s)	7.25 Yr(s)

8.3.4 Sensitivity Analysis

A sensitivity analysis has been performed, under which the following scenarios have been modelled:

- Capital cost: ±20%.
- Operating cost: ±20%.
- Interest rate: ±2%.
- Throughput: 35%, 65%, 85%.
- Oil Price: high, low, HHP.

These results are displayed below. As anticipated, higher oil prices reflect a higher fuel cost and require increased tariff to compensate. This increase could be partially absorbed through economies of scale as reflected in the higher capacity scenarios.

Exhibit 8-35 – Base Case - Operating Year 1 Tariff Make Up

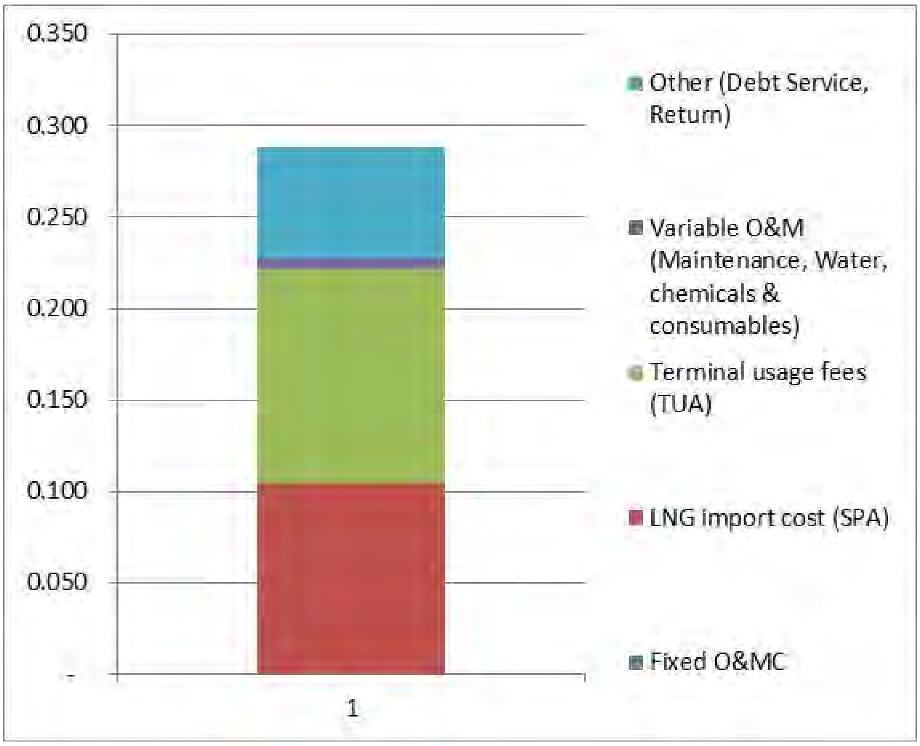


Exhibit 8-36 - Power Plant Sensitivity Analysis

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Avg. Generation p.a (MWh)	Equity IRR	Year 1 Tariff (USD/kWh)	Tariff (MUR/kWh)
Base Case	156 523	126 353	177 276	403 488	20.0%	0.29	8.67
+20% Capex	187 828	126 353	212 708	403 488	20.0%	0.30	9.09
-20% Capex	125 219	126 353	141 845	403 488	20.0%	0.27	8.25
+20% Opex	156 523	151 623	177 276	403 488	20.0%	0.33	9.99
-20 Opex	156 523	101 082	177 276	403 488	20.0%	0.24	7.36
Interest 2%	156 523	126 353	180 906	403 488	20.0%	0.29	8.78

Case	Capex (USD '000)	Avg. Opex	Peak Funding (USD '000)	Avg. Generation p.a (MWh)	Equity IRR	Year 1 Tariff (USD/kWh)	Tariff (MUR/kWh)
up							
Interest 2% down	156 523	126 353	173 630	403 488	20.0%	0.28	8.57
35% Capacity	156 523	93 547	177 276	282 442	20.0%	0.33	10.06
65% Capacity	156 523	119 155	177 276	524 535	20.0%	0.21	6.36
85% Capacity	156 523	153 315	177 276	685 930	20.0%	0.20	5.87
High Oil price	156 523	130 313	177 276	403 488	20.0%	0.29	8.81
Low Oil price	156 523	115 844	177 276	403 488	20.0%	0.27	8.10
Henry Hub price	156 523	108 891	177 276	403 488	20.0%	0.27	8.12

8.3.5 Financial Model

It is noted that while care has been taken in constructing the financial model, it has not been independently audited. Appendix 4 details the model's annual financial statements ("AFS").

8.4 Discussion and Recommendations

As indicated before, the financial models for the LNG Regasification Terminal and 100MW CCGT Power Plant have been prepared on a limited recourse project finance basis. This approach requires the cashflow of the project to be sufficient to recover the full cost of the investment and a return for the investor. For the purposes of this study it has been assumed that the investor would require a minimum Nominal Internal Rate of Return after tax of 20%, which is considered reasonable for this type of investment. The respective tariffs were therefore calculated to achieve this return. Should the funding model and return assumptions be adjusted it would naturally have an impact on the required tariffs.

The bulk of the cost of these projects, excluding the LNG cost, is of a fixed nature. This has the result that both projects are very sensitive for the throughput or capacity factor assumed.

In the case of the LNG Regasification Terminal, the minimum practical terminal size results in a facility that is underutilised for the most part during the evaluation lifetime of the project. This results in a regasification tariff that is higher than what would normally be expected from a facility of this nature that is more optimally utilised. As can be seen from Exhibit 8-13 the effective tariff per MMBtu does come down considerably as the throughput volume increase. To ensure the economic case of the Regasification Terminal is optimised it is therefore necessary that the market for natural gas in Mauritius is developed as quickly and to the fullest extent possible. As an alternative the Government of Mauritius could consider support mechanisms such as subsidies during the early years to either improve the economics for the Terminal for the off takers.

The economic case for the Power Plant is equally dependent on the dispatch factor assumed. Based on the regasification tariff required to make an economic case for the Terminal and the assumed LNG delivered cost it would be difficult to justify the cost of power generation from the CCGT Power Plant if it is operated at a base case of 50% dispatch factor. As can be seen from Exhibit 1-36, the economic case improve dramatically when the Power Plant is operated at a dispatch factor of 65% or 85% respectively and a high natural gas growth scenario for the Mauritian market is assumed.

In conclusion it would appear that some level of strategic Government support would be required in the short to medium term to introduce LNG successfully into the Mauritian market and to ensure the economic case of the LNG Terminal and CCGT Power Plant are sufficiently robust to attract investment and raise finance.

9. CONSIDERATION OF NON-FINANCIAL FACTORS FOR THE LNG PROJECT IN MAURITIUS

The scope of this study excluded an investigation into the non-financial factors (incl. environmental, social) that can be considered in order to motivate the case for LNG import and use in Mauritius. As seen in the previous section, based solely on a financial analysis, the low LNG demand (and subsequently the low throughput for the LNG terminal) impacts negatively on the project economics. One way to increase the economic viability would off course be to increase the demand for LNG through further exploring bunkering, hub and spoke model to Reunion, increase in refining activities etc. Also, it is possible that the supply dynamics and small scale LNG infrastructure developments, and therefore the price of LNG, may become more attractive in the future.

However, there may be other non-financial factors Mauritius could explore that could ultimately make the case for using LNG more attractive. These can be quantified and the associated cost projections can be included in the financial model. Possible aspects to consider could include, but not limited to

- To diversify the energy mix of the country and increase energy security
- Reduction in harmfull emmisions and related environmental benefits. This can be monetized, amongst others, by possible credits that can be obtained from reducing harmfull emmisions i.e. CDM mechanism.
- The enhancement of the image of Mauritius as a country and tourist or investment destination due to its positive low carbon policies and the associated benefits to the economy
- The impact on health of the population due to reduced polution and the associated medical cost savings or reduction in loss of productivity in the workplace.
- The impact of embarking on a national infrastructure drive to implement LNG use in the power and other industries in terms of job creation and other downstream economic benefits

Normally, the above aspects would be long term considerations on a national level and realising the possible benefits may require initial government incentives to stimulate market uptake of LNG in the shorter term. Further study was suggested as an option by WorleyParons to CEB during project proposal stage and may be considered going forward. WorleyParsons EcoNomics process and the delta tool are ideally suited for economic modeling under conditions of uncertainty, multiple stakeholders, numerous non-financial costs and benefits associated with the implementation of the ideas contained above and the long-time frames involved. WorleyParsons EcoNomics process is focused on factoring non-financial costs and benefits into option assessments to help our clients make decisions with long-term consequences.

The below section elaborates on the CDM and how it may relate to the LNG project in Mauritius with the aim to supply CEB with background information on the topic as part of this report; however, it should be noted that it is outside of the core scope of the study and therefore may require further study to make final reccomendations.

9.1 CDM review for the LNG project in Mauritius

Although the consideration of revenue from selling carbon credits in the financial models is beyond the scope of this specific study, a short overview of the potential for registering the proposed LNG project in Mauritius under the Clean Development Mechanism (CDM) program is presented here.

The first section provides a summary of CDM projects in Mauritius and market opportunities for those credits. While there is the potential for the projects to be registered under the CDM program and sell credits, the CDM market has recently become very depressed due to an oversupply of credits. The second section addresses the current status of the CDM market and some of the results of the recent downturn.

9.1.1 CDM Projects in Mauritius and Potential Markets for Credits

The proposed Mauritius LNG fired power generation projects would potentially be eligible for registration under the UN CDM program. Currently two other projects in Mauritius have been registered in the CDM [43]:

- Plaine Des Roches Wind Farm
- Mare Chicose Landfill Gas Project

Critical to having the projects registered under the CDM is demonstrating that revenues generated from the CER's (i.e. Carbon Credits) are critical for the projects moving forward. Projects that move forward based on their economic merits, i.e. they are inherently the most economically favourable, are not typically eligible for registration under the CDM program. A first step in pursuing registration of the projects under CDM program would be to assess if the CDM program would play this vital role. Additionally, documenting the selection process with CDM, from the early stages of the project development, is important to demonstrate the role considering CDM is playing in the investment decision.

With regards to potential markets for the credits generated from the proposed projects, the Environmental Defence Fund listed and compared 18 Emissions Trading Schemes (ETS) [44]. Many of the ETSs have restrictions on the credits that emitters can use to meet their CO2 emissions reduction obligations, see Exhibit 9-1. These restrictions include the percent of an emitter's obligation that can be met with credits, the project type and project location. Based on the information provided, if registered under the CDM, the credits, Certified Emissions Reductions (CER's) under the CDM, equivalent to 1 tonne CO2 emissions reductions, from the projects in Mauritius could be sold to the Australian, New Zealand, Mexico, Brazil, Norway and Swiss ETS's. A more detailed study involving brokers of emissions credits to identify if buyers would be interested in purchasing the CERs from the Mauritius projects will be required to confirm this.

Exhibit 9-1: Comparision of ETS Restrictions

ETS	Credit Sources/Limitations
EU	JI or CDM, CERs must be from Least Developed Countries (LDCs)
Australia	CERs or ERU from international sources may cover half of obligations
California	Open to international sources, but sources to date have been locate in US, Canada, and Mexico
New Zealand	CERs and ERUs (Emissions Reduction Unit)
Quebec	Sources include methane ozone depleting substances destruction
Mexico	CERs from CDM
China	To be Determined (TBD)
RGGI	CERS, but not related to power generation efficiency improvements or fuel switching
Brazil	CERs from CDM
South Korea	CERs after 2020, up to 10% of an entity's obligation
Kazakhstan	ERUs
Alberta	Alberta based reductions
Norway	CERs and ERUs
Switzerland	CERs and ERUs
Tokyo	Credits must be Tokyo based
Japan	Current ETS uses credits from domestic sources, proposed ETS would allow use of CERs
India	TBD

General status of the CDM Program and Carbon Markets

Since 2011, there have been several changes in carbon markets which have had impacts on the UNFCC CDM program and projects [45]. In general there have been an oversupply of credits to the market which have driven the down the price of credits.

In 2011 a CER was valued on the order of €10. Market predictions at this time indicated that the prices would remain the same or rise over the next ten years. Since that time, CER prices have dropped to less than <€0.50 [46]. In general carbon markets have become severely depressed. Other examples of difficulties in carbon markets include:

- Value of credits in European Union Emissions Trading Scheme market have dropped from ~15 €/tonne to €5-6.
- Australian market was to trade above 23AUD/tonne, however the market trading scheme is potentially being abandoned for other mechanism to control emissions

The decrease in CER prices have had a negative impact on the CDM program including projects no longer operating and a reduction in the number of new projects. There is a growing effort to correct this trend with a specific emphasis being placed on the overabundance of CER's in the market through increased scrutiny during project reviews and country restrictions for the source of CER's. For example, the European market, which is the largest purchaser of CER's, has imposed the restriction that the CER's must come from projects in Least Developed Countries. Mauritius is not considered a Least Developed Country. Other carbon markets have placed similar restrictions or that the credits must come from projects in the region of the market.

Another impact of the decrease price of CERs is companies and consultants are no longer emphasizing these business activities. In the last two years, this network has decreased in size by 50%. As an examples, DNV and SGS, two of the largest players in this market space, has stopped providing validation and verification services for the CDM [47],[48]. The decline of activity in this area may lead to a loss of CDM expertise that may hamper the development of new CDM projects and similar greenhouse gas emissions reductions mechanisms.

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Appendix 1 Inception Report

282570 – INCEPTION REPORT

PROJECT EXECUTION PLAN (PEP)

1. PROJECT INFORMATION

Project Title	Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius	Project Risk Classification/Delivery Model		Moderate / Misc
WorleyParsons Project No	282750	Document No	282570-MauritiusLNG-IR-01_Rev3	
Project Customer	CEB of Mauritius	Customer Project No	RFP-CPR-3574	
Project Manager	James Swift	Customer Phone No	+230 601 1182	
Project Directory	P:\Power\Gas turbines\282570 - Mauritius LNG			

2. PROJECT COMMUNICATIONS

Details of personnel to who formal communications are to be addressed:

Communication to the Client:	All communication can be done via e-mail to the CEB Project Eng: Rakesh Kumar Dhununjoy rakesh.dhununjoy@ceb.intnet.mu The following CEB personel to be copied: • PM - Mohammad Shamshir Mukoon shams.mukoon@ceb.intnet.mu • Principle Eng (Mech) - Manoj Kumar Jahajeeah manojkumar.jahajeeah@ceb.intnet.mu • Production Manager - Hassen Fakim hassen.fakim@ceb.intnet.mu For environmental issues, Mr. Sookraz can be copied • Environmental officer: Sanjay Sookhraz sanjay.sookhraz@ceb.intnet.mu All commercial items will be send to Mr. Dhununjoy, who in turn will distribute internally. For items requiring special permission as per the *Contract*, a formal letter will be send via e-mail for acceptance.
Communication from the Client	All communication can be done via e-mail to WP Project Eng. James Swift, james.swift@worleyparsons.com. The WP team can be copied as appropriate. Below is the details of the WP team: • Power Specialist - Kajal Mukherjee (Reading) Kajal.Mukherjee@WorleyParsons.com, Power PM - David Stauffer (Reading) David.Stauffer@WorleyParsons.com • LNG specialist - Bhatia, Madhavendra (Singapore) Madhavendra.Bhatia@worleyparsons.com • PMT specialist - Mocke, Gary (Cape Town) gary.mocke@WorleyParsons.com, Cantelmo, Clemente (Cape Town) Clemente.Cantelmo@WorleyParsons.com • Local representative (SJP Consulting Eng) – Anand Gungoosing gungoosingh@sjpce.com, Raj Servansingh servansingh@sjpce.com • Energy Economist – Francois Viljoen francois@crescopf.co.za • Automotive specialist – John Stavers johnstavers@hotmail.com • LNG Commercial Specialist (Energy Economist) – Gauthier van Marcke gvanmarcke@galwaygroup.com

A Sharepoint site has been created for the project in order to share information that may be too large for e-mail or to keep a record of documents shared. The Client & WorleyParsons team has different levels of access to the site as required for effective file sharing. The site has link: https://zaprojects.worleyparsons.com/sites/282570muslng/default.aspx

3. INTRODUCTION, SCOPE OF WORK AND DESIGN REQUIREMENTS

Introduction

The Contract for the *Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius* was signed on the 18th of November 2013. The Consultant commenced with the project on the 28th of November and various team members conducted a visit to Mauritius during the period 3 to 7 December 2013.

The main purpose of the visit was to meet with the CEB for the official project kick-off meeting, meet with other relevant stakeholders and to visit some of the sites identified by the CEB for a possible LNG power plant. The major objectives were to establish the relationships with parties who can provide further input and assistance to the project, to refine the understanding of the project scope and to familiarize the team with the geographical and regulatory environment relating to the project. The Minutes for the various Meetings are given in **Appendix A.**

The following meetings and visits was conducted during the visit to Mauritius:

- CEB – Kick-off meeting (KOM) and Wrap up meeting;
- Mauritius Port Authority (MPA);
- Ministry of Environment and Sustainable Development (MOESD);
- Ministry of Housing and Land (MHL);
- State Trading Corporation (STC);
- National Transport Authority;
- National Transport Corporation;
- United Bus Company; Triolet Bus Service site; Government Mechanical Workshop; Rose Hill Transport.
- Fort Victoria PP site visit;
- St. Louis PP site visit;
- Les Salines site visit;
- Old Port site visit (Bois des Amourettes – East coast)
- JinFei leased land site visit (Baie de Tombeau – West coast);

Based on the information and learning gained during the visit to Mauritius and consequent discussions, the Consultant has compiled this Inception Report in the standard WorleyParsons format. The purpose of the inception report is to reach agreement on various aspects of the project at the start of the ensuing study. This report is by no means exhaustive, but contains the basic assumptions and agreements as at this stage of the project. Possible updates may be required as the Consultant progresses with the study. The Inception Report also does not replace the Contract, but serves as an update in understanding of some aspects of the scope and execution of the project and will, in cases where conflict arise between the IR and Contract, take precedence. The next sections provide more detail.

Project Objectives and Success Criteria

The Scope of Services for this study is presented in *Appendix A of the Contract* and has therefore not been reproduced in this report; it should be used as a reference.

Besides the Objective (Point 1 in *Appendix A of the Contract*) and Scope of Services (Point 1 in *Appendix A of the Contract*), the Consultant has also learned, during discussions with the CEB at the KOM, that the following objectives are to be satisfied:

- The CEB wishes to gain knowledge in general about the options for LNG import, storage, handling and usage in Power Plants and Transportation Sector. The final recommended options as resulting from the study will be presented in more detail by the Consultant, but the CEB would value general descriptions on the other options also as a means of informing themselves on the technology and options available.

- The CEB is being questioned by other parties on the use of LNG and it has been requested that the study be presented in such a manner that it can be read and understood by non-technical people; possible from a political or financial background also.

- The CEB would also value a clear “roadmap” on completion of the pre-feasibility on further steps to be taken in order to move to final conclusions on the use of LNG in Mauritius for Power Generation, Transportation and other usage.

- It has been mentioned in the KOM that the CEB requires an indication of the skills required to implement LNG usage in Mauritius for power generation. The format of such a discussion would depend on the outcome of the pre-feasibility study and the further steps suggested. Should the pre-feasibility study find the use of LNG to be viable, a high level proposal will be presented in terms of up-skilling.

Data and information requirements (DIR)

In the *Contract, Appendix F* presents the Data and information requirements (DIR) list that has been requested from the Client. During the Client KOM, a discussion was held around each item on the list. The list has been annotated with the responses from the Client and is attached here as **Appendix B**.

A register of the documents received from the Client till date is also presented for record in **Appendix C.**

It should be noted that further data requirements may become evident as the study progress and this will be requested via the communication channels as listed above.

Refined methodology of study execution after visit to Mauritius

The scope and methodology for executing the work has been well described in *Appendix A of the Contract* and serves as a good basis for the Inception Report refinement. In order to capture the changes to the Contractual scope for easy reference, the Consultant has indicated the refinements using the Microsoft Word track Changes feature. It should be noted that the refinements are intended to hone the scope based on new learning during the site visit and to get agreement on some of the preliminary assumptions made. Some Basis of Design information has also been provided at this early stage. **Appendix D** gives the marked up methodology.

Further Basis of Design information may be presented shortly for acceptance as the study progress.

The Way forward

The Consultant's team are now mobilized, the visit to Mauritius is completed and outcomes recorded in this report. The next steps are for each discipline to continue with their study as per the information received from CEB, the learning during the visit to Mauritius and as required by the scope document / schedule. The team will have regular communication / meetings to coordinate inputs and to share findings in order to make sure we do not work in isolation and that an integrated result is produced. Periodic discussion with the Client may also be convened in order to check main assumptions and findings to make sure it meets the expectation of the CEB.

Client acceptance of the Inception Report is required as this forms the basis of the Pre-Feasibility Study. Hereafter, the compilation of the draft Pre-feasibility report will continue. The draft Pre-Feasibility report will basically contain an outline of the Final Pre-Feasibility report in order to reach agreement with the Client on the format and structure and perhaps some of the main findings available at the point of submission. Once agreement is reached on the draft Pre-Feasibility report, the final Pre-Feasibility report will be compiled and submitted for Client acceptance.

The Schedule will be as presented in this report in Section 7.

4. HSE Office Based ☒ Field Based ☐ Other ☐:

Are there any specific HSE considerations? YES ☒ NO ☐ If yes provide details:

The majority of the work will be done from the WP team respective offices. However, there was / will be Client and Site Visits in Mauritius for the Client Kick-off meeting. Mauritius, being a low risk country, does not require a TRAP as per WPMP, but self-managed travel according to the International Process has to be followed.

Also, HSE requirements as set out by the Client will be assessed & followed if adequate for site visits to the CEB power plants.

5. LESSONS LEARNT Any previous lessons learnt or prior client history relevant to this project? YES ☒ NO ☐ If yes provide details:

The WorleyParsons team brings with it a wealth of knowledge and experience relating to the use of LNG in the Power Industry and elsewhere. Lessons learned are being shared internally and will be scrutinized for applicability to the current project and developed as the WP team progress with the study. There are no lessons learned directly applicable (without further investigation and refinement) that can be provided at this early stage in the study. However, some lessons learned were presented during the CEB wrap up meeting on the technology options for the Power Technology and the LNG import and storage.

The final Pre-Feasibility report will provide details on lessons learned and how they apply in order to arrive at conclusions for the current project.

6. BUDGET Is detailed budget attached? YES ☐ NO ☒ If no provide budget details:

The project is a lump sum project with total value as stated in the *Contract*.

7. SCHEDULE Is detailed schedule attached? YES ☒ NO ☐ Provide milestones and due dates:

The latest schedule is attached in **Appendix E.**

8. DELIVERABLES Is list of agreed deliverables attached? YES ☐ NO ☒ If no list deliverables and due dates:

Final Inception Report	6 January 2013
Draft Pre-Feasibility Study Report	5 February 2013
Draft Final Pre-Feasibility Study Report	18 March 2013
Final Pre-Feasibility Study Report	10 April 2013

9. DESIGN REVIEWS, FUNCTIONAL REQUIREMENTS, GENERAL INFO, REFERENCE DOCUMENTS, SPECIAL TECHNICAL CONSIDERATIONS, MATERIALS, LONG LEAD ITEMS, PARTICULAR RESPONSIBILITIES, CONSTRUCTION YES ☐ NO ☒

Items listed here is not applicable to the Pre-feasibility stage. No feasibility, detailed design or construction will be conducted. Input relevant to this study applicable under this section is contained in the Scope document.

OTHER Any other specific considerations (i.e. special procedures, project status reporting, job books, risk/reward, records retention, project data handover requirements, archiving requirements, etc.)?
YES ☒ NO ☐ If yes provide details and responsible person:

No specific reporting requirement. However, it has been requested during the KOM that a monthly feedback be provided to the Client on the progress of the study.

No specific Client document format is required. The standard WorleyParsons format will be used.

Attachments ☒ Finalized WPMP Requirements Task List Printed from the WPMP Page

Appendix A – Minutes of meetings – Mauritius visit	Appendix E – Updated schedule
Appendix B – Annotated DIR	
Appendix C – Register of documents received from CEB	
Appendix D – Refined methodology document	

CUSTOMER APPROVAL

Comments:

Name: R. K. Dhunnunjoy **Signature:** RKDhunnunjoy **Date:** 14 Jan 2014

PROJECT APPROVAL (To be completed by Project Manager)

Revision Status: Rev 3 **Revision Description:** Document updated with Client comments from Rev2

Name: James Swift **Signature:** JS **Date:** 13 Jan 2014

Note: Please ensure that a check is made with customer specific compliance requirements for all project personnel.

Compliance checked.

Appendix A - Minutes of meetings – Mauritius visit

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Kick off meeting with CEB

PARTICIPANT NAME & ORGANISATION			**DATE**	4 December 2013
CLIENT		CEB of Mauritius	**TIME START**	10:30am SA time
PRESENT:			**TIME FINISH**	2:30pm SA time
R. Dhununjoy	: CEB	Project Engineer		
D. B. Seblin	: CEB	Mech. Eng. Fort Victoria		
S. Sookhraz	: CEB	Environmental affairs Officer		
M. S. Mukoon	: CEB	Corporate Planning and Research Manager		
James Swift	: WorleyParsons	Project Engineer		
F. Viljoen	: Cresco	Financial Specialist		
K. Mukherjee	: WorleyParsons	Power Specialist		
M. Bhatia	: WorleyParsons	LNG Specialist		
Clemente Cantelmo	: WorleyParsons	Marine Eng.	**LOCATION**	CEB offices
John Stavers	: Consultant	Transport Engineer	**RECORDER**	James Swift

APOLOGIES:

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RECORD OF DISCUSSIONS

ITEM	ITEM DETAILS	ACTION
1.	**OneWayTM Moment** *James present OneWay moment – lost in translation: focussing on communication in multinational team.*	
2.	Project is undertaken from Corporate Planning and Research Department within CEB. All communications directed to Rakesh with copy to Mr. Mukoon. Mr. Sookhraz is available for support and environmental aspects.	
3.	Discussed the schedule for the visits while WP team is in country. Also provided time for general introductions of team members. Mr. Mukoon could only join later from 12:pm.	
4.	The DIR was discussed – see attached annotated list with the actions / response indicated per point.	
5.	Rakesh mentions that CT Power coal plant will be commissioned in 2017. This plant shall use a circulating fluidized bed combustion (CFBC) boiler technology (see p53 IEP). CEB will be 26% shareholder. Despite the PPA being executed in Dec 2008, this project has been significantly delayed as Ministry of Environment and Sustainable Development (MESD) did not grant its EIA license. The project only obtained its EIA license in January 2013.	
6.	The new 100 MW plant (CCGT) will be either IPP or CEB owned, but will depend on downstream outcomes.	
7.	Renewable Energy Planned: - 39 MW from Wind - 25 MW from Solar Expected commissioning of the RE projects in 2015 General note: Wind comes from South East	
8.	CEB has planned to retire 6x5 MW old Pielstick engines and replace them by 4 x 15 MW medium speed diesel engines as part of the redevelopment project of St Louis power station	
9.	General discussion around advantages of LNG vs coal and cost of LNG vs coal was conducted. *Coal power plants have a bad public perception and there is a growing awareness of environmental issues."Polluter pays" policies are on their way.*	
10.	Kajal states that IPP Plants have 80-90 % capacity factor, CEB's base plant (Fort George) has a CUF of 50-60% while the medium speed diesel has a CUF ranging between 25-40%.	
11.	In Mauritius around 40% coal, 40% HFO, 16% bagasse and 4% hydro fuel mix.	
12.	No carbon tax currently, but environmental levy on fuel imported. *Taxes and incentives for cleaner fuels would be heavily influenced by the Ministry of Economic development and Finance.*	
13.	Gasoline for vehicles is priced at about 52 MUR/l, equivalent to 2.2 SGD/l.	
14.	Due to environmental reasons – LNG may be subsidized. A key government document for us to align with is the M.I.D., "Mauritius - Sustainable Island"	
15.	Electricity selling prices are published on CEB's website; Any tariff increase requested by CEB can only be implemented upon approval by the Government	
16.	*13:45: Mr Thannoo and Mukoon joins us. Mr Thannoo emphasizes that this study is of*	

ITEM	ITEM DETAILS	ACTION
	national importance. Mr. Mukoon gives background basically describes what is in IE*P. He also states that LNG import and use would be national issue, but Ministry of Finance and Economic Development did not want to fund the study and CEB decided to do so. Mr. Mukoon also acknowledges that next step will be bankable feasibility if pre-feasibility finds project to be viable. Economics, as well as environmental issues, will be important factors in decision making.*	
17.	The IPP contracts will be re-negotiated during the period 2018 - 2020. The plants do not comply with European environmental standards and they are inefficient - It is difficult to meet the EU environment standard unless major modifications are brought forward. It is possible that some would need to be shut down.	
18.	*Bhatia conducted a high level discussion on the project from slides prepared in order to stimulate further discussion on the scope and outcomes of study.*	
19.	John states we may have to make assumptions on other large users. This will be in high level only as described in scope. This may include bunkering.	
20.	Mr. Mukoon requests the WP team to also consider the capacity building requirements, should this project be deemed to be viable and LNG skills is required at a future time.	WP team to note.
21.	Capacity planning is well explained in the IEP 2013-2022	
22.	Three IPPs namely CTBV, CEL, FUEL have “take or pay” type contract arrangement. The remaining 2 IPPs are based on two part tariffs i.e. having both capacity and energy payment contracts.	

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Mauritian Port Authority

PARTICIPANT NAME & ORGANISATION		**DATE**	4 December 2013
CLIENT	CEB of Mauritius	**TIME START**	3:30pm SA time
PRESENT:		**TIME FINISH**	5:00pm SA time
Capt. L. Barbeau	Port master MPA		
Mr S Goburdhone	Director port development MPA		
Mr H Kalee	Director port operations MPA	**LOCATION**	MPA office
Mr B Dhunnoo	Technical services manager	**RECORDER**	James Swift
Mr J Swift	WorleyParsons - PE		
Mr M Bhatia	WorleyParsons – Power spec		
Mr K Mukherjee	WorleyParsons – LNG spec		
Mr J Stavers	Consultant – transport		
Mr A Gungoosingh	SJP		
Mr C Cantelmo	WorleyParsons - PMT		
APOLOGIES:			

RECORD OF DISCUSSIONS

ITEM	ITEM DETAILS	ACTION
1.	A layout of the port was presented by Mr S Goburdhone. See notes below	
2.	Port has LPG Storage of 15,000 t at Mer Rouge and some 5000t at Roche Bois	
3.	No Tsunami threat likely - 2004 Tsunami almost no impact in the Port	

Description of port layout

Refer to attached scanned document

South

1. Bulk Sugar: This is currently not utilized at max capacity, both in terms of storage area and jetty loading operation

2. Les Salines: this area and the whole strip adjacent to the water has been allocated for a waterfront development (leisure purpose)

3. Fort William: A 5,000 cu.m HFO tank (project led by CEB) is going to be constructed with pipework to pump HFO to Victoria power station

Note: Environment Impact assessment for the tank farm has been carried out by CEB.

North

4. Ex Dockers flat: area earmarkedforpetroleum storage

5. Terre Rouge River Estuary a Ramsar site and protected area

6. Container Terminal area MPA is proceeding with the extension of the existing berth by 240m so as to obtain a total quay length of 800m capable to accommodate large container vessel

7. Oil jetty: Mainly used for Oil and LPG import (Noted LPG is not delivered in cryogenic conditions). The jetty accommodates ships of approximately 65,000 DWT which has length of about 270mand draft approx. 13 m. It has a reasonably high berth availability , being closed only 15 to 20 days per year – typically during cyclones with waves reaching max heights of 3m (in extreme conditions).

8. Fort George: this is a heritage site and therefore protected by national heritage legislation. Near to Fort George there is a dry dock for ship's repair, construction and maintenance and two storage tanks operated by TOTAL, which initially were used to store Ammonia and are now been used for storage of fuel oil and gas oil.

   Terminal 2: This is a multipurpose terminal where General Cargo, containers, cement, coal vesssels ect. are handled. At Quay 1, petroleum products are also unloaded.

Expansion plans

2014 will see a new master plan being prepared. Amongst the most relevant additions/modifications:

Dredging/Reclamation operations: The navigational channel to the MCT will be dredged from, 14.5m to 16m. Some 1.15million $m^3$of material will be recovered and used for land reclamation at Fort William & Fort George.

The land reclamed at Fort William will be used for the development of a number of facilities such as :

- sea food and fish processes
- dry dock
- tanks for bunkering
- it was pointed out that the final land use will be determined by the Master Plan Consultants to be appointed.

<u>Additional notes</u>

1. Cyclone warning system is available: cyclones usually last up to 24 hrs and then 3 days of rough sea and swell normally follow.

2. Tidal variation is in the order of 0.7m.

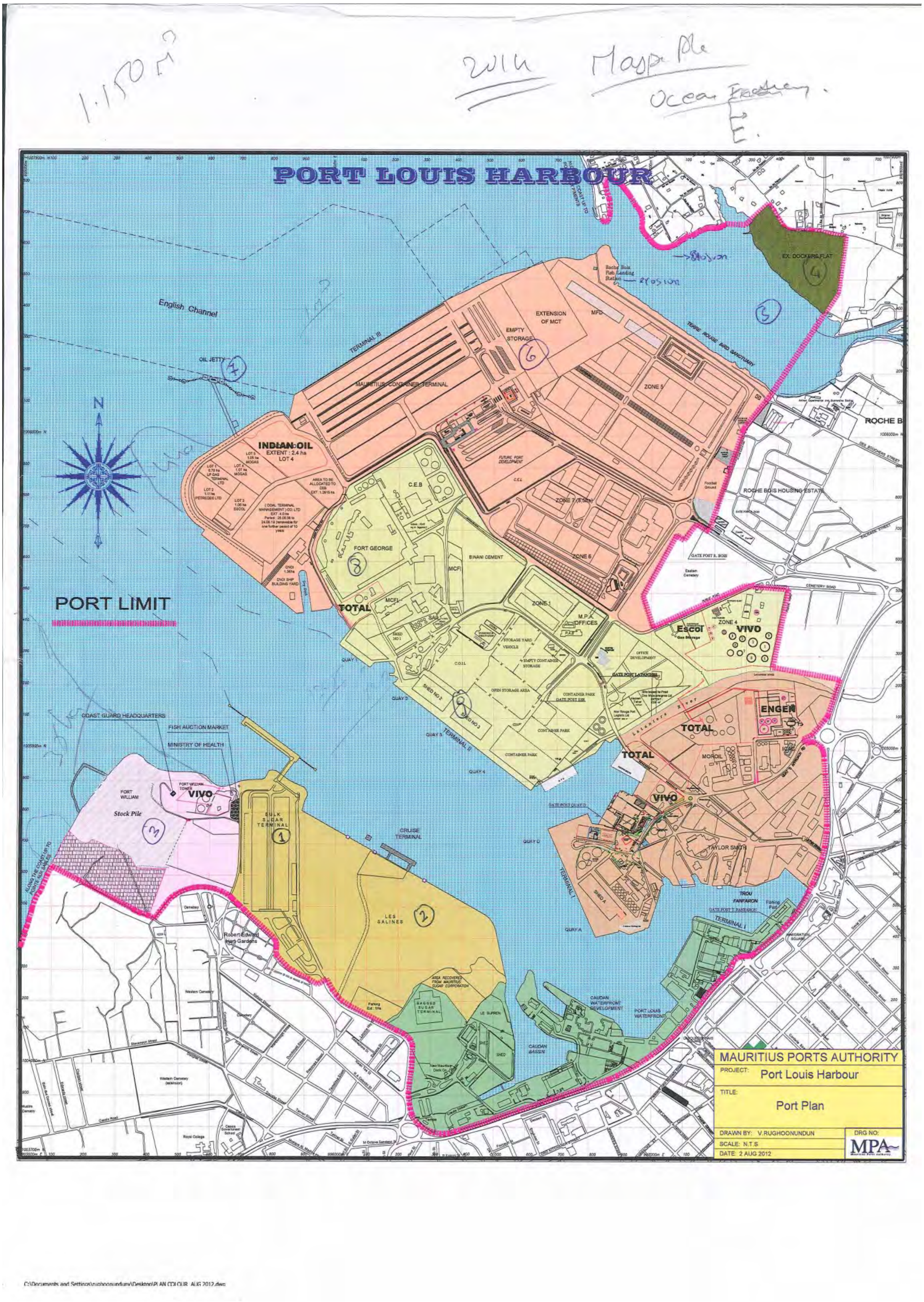
3. Siltation is not a big issue in the harbor, but the north area (in the marine protected area -5) there have been some erosion issues, mostly at the entrance.

4. In terms of navigation, the port authority has a capacity for handling large vessels (staff skills and tug fleet).

5. It is likely that existing infrastructure is not viable for LNG purpose – the port works at high capacity and ships continuously access the terminal. A LNG berth may require partial closure of the terminal. An option could be trying to use the existing bulk sugar jetty, but this is located in the access channel and may cause severe restriction to vessel access and port operability while LNG is on berth – for at least 24 hrs. Given that there are significant movement of fishing, general cargo cruise and other vessels. The port authority cannot accept any disruption of the shipping activities.

6. The upgrading of the existing BST Jetty has also been discussed. This may not be feasible, as given the dimensions of the loading platform and the trestle, accommodating a 5m wide pipe rack and additional loading arms would require extra space which is not available.

7. An FSRU (not clear)option (located on the northern side, where the jetty currently is) will also be analysed but this will require larger exclusion areas and will impact on existing oil jetty operation. Also during cyclone the FSRU will have to be moved and find shelter somewhere else along the coast (where cyclones won't have significant impact).


PORT LOUIS HARBOUR
English Channel
OIL JETTY
TERMINAL III
MAURITIUS CONTAINER TERMINAL
EXTENSION OF MCT
EMPTY STORAGE
ZONE 5
EX. DOCKERS FLAT
TERRE ROUGE AND SANCTUARY
ROCHE B
ROCHE BOIS HOUSING ESTATE
INDIAN OIL
EXTENT : 2.4 ha
LOT 4
C.E.B
FORT GEORGE
BINANI CEMENT
MCFI
TOTAL
ZONE 1
M.P.A. OFFICES
Escol
VIVO
ZONE 4
ENGEN
TOTAL
MOROIL
TOTAL
VIVO
TAYLOR SMITH
TERMINAL I
PORT LIMIT
N
COAST GUARD HEADQUARTERS
FISH AUCTION MARKET
MINISTRY OF HEALTH
FORT WILLIAM
VIVO
Stock Pile
BULK SUGAR TERMINAL
CRUISE TERMINAL
LES SALINES
MAURITIUS PORTS AUTHORITY
PROJECT: Port Louis Harbour
TITLE: Port Plan
DRAWN BY: V.RUGHOONUNDUN
SCALE: N.T.S
DATE: 2 AUG 2012
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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Ministry of Environment and Sustainable Development

PARTICIPANT NAME & ORGANISATION			
CLIENT			CEB of Mauritius
PRESENT:			
James Swift	:	WorleyParsons	Project Engineer
M. Bhatia	:	WorleyParsons	LNG Specialist
Clemente Contelmo	:	WorleyParsons	Marine Eng.
John Stavers	:	Consultant	Transport Engineer
K. Mukherjee	:	WorleyParsons	Power Specialist
R Gungoosingh	:	SJP	Civil Eng. Local partner
S Sookhraz	:	CEB	Environmental Affairs Off
A Allock	:	MOESD	Environmental Off
R Aukhojee	:	MOESD	Environmental Off
R Sadayer	:	MOESD	Environmental Off
R K Dhununjoy	:	CEB	Project Engineer

DATE	5 December 2013
TIME START	9:00am SA time
TIME FINISH	11:30pm SA time
LOCATION	MOESD office
RECORDER	James Swift

APOLOGIES:

RECORD OF DISCUSSIONS

General discussions were held around the requirements and role of the Ministry of Environment and Sustainable Development to inform the team appointed by CEB for the study as noted above. The main points relevant to the study are noted below.

ITEM	ITEM DETAILS	ACTION
1.	Specific information can be obtained from the website of the Ministry of Environment and Sustainable Development (MOESD) http://environment.gov.mu.	
2.	All new power stations will warrant submission of an EIA report as per the existing regulations	
3.	Coastal area coral preservation requirements: contact Ministry of Fisheries (website)	
4.	Get Outline Scheme from Ministry of Housing and Lands for zoning of specific areas.	Discuss Outline Schemes with MOHL
5.	An EIA licenses is required only bulk storage and distribution while filing stations do not require any EIA license	
6.	Distribution of re-gasified LNG; pipeline underground option steps to follow:	
	a) EIA submitted to MOESD b) Way leave etc. to be obtained from land owners	
7.	EIA – any qualified company can do –A list of consultants is available on website of the MOESD.	
8.	Right of Way for Pipeline that falls under state lands is obtained from the Ministry of Housing and Lands.	
9.	The site on the east of the Island (old port – see Dec 6th trip notes) may be difficult for the power plant as it has corals and Ministry of Fisheries has special regulations on not damaging/ disturbing the corals.(Not Clear- to rewrite)	
10.	As per the EPA,, it takes about 3 months for approval of EIA after submission.	
11.	After EIA approval is obtained from MOESD, then you need to apply for building permit from the institutions under whom the land area will form part (e.g Municipalities, District Council)	
12.	Exclusion zone: 500 m from Coastline for any wastewater discharge, 1 km from Residential areas distance for siting Power Plants.	
13.	For air pollution (emissions) guidelines, see MOESD website – new guidelines published: Mr Sookhraz will give new guidelines to team (Emission standard; ambient air standard)	Mr. Sookhraz to provide
14.	Transport: Suggest doing fuel distribution application (currently EIA not required for fuel distribution) in same EIA as bulk fuel storage EIA. Any oil storage storage will require EIA approval for installation.	
	a) Ministry of Transport (NTA) – regulates all vehicles b) Only new cars and 2nd hand imported cars are taxed on their published CO_2 emission rates under the terms of the CO_2 rebate / levy mechanism. The current threshold level is 158 grams CO_2 / km, if the vehicle emits more a levy is imposed, if it emits less a rebate applies. Next year the threshold level will drop to 150 grams CO_2 / km c) Currently the country does not impose annual emissions tests on vehicles and does not have the equipment to test any else than "black	

ITEM	ITEM DETAILS	ACTION
	smoke". Legislation only on diesel engines (Opacity 40% to limit). Spot checks are made and if a vehicle emits more than 40% black smoke fines are imposed, for more than 70% a prohibition notice will be served on the vehicle. d) Petrol, diesel and LPG used in the transport sector are subject to a Rs 0.30 / litre M.I.D. levy. e) It is understood that the National Transport Authority is considering implementing at some stage maximum Euro emissions standards on new vehicles being imported. f) It was suggested that we should obtain a copy of the recent budget speech in respect of taxation on road transport taxes / levies.	
15.	Monitoring has been done on the quality of Mauritius ambient air; but not on the effect of the air quality on public health.	
16.	The CEB power plants use HFO with a maximum sulphur content of 3% by weight. There is no CO2 Tax Credit / Incentive inthe current regulation for power plants.	
17.	Dr Remyead from a local Mauritius University has performed a study on the Impact of traffic on Mauritius. WP could try and obtain study if relevant.	
18.	Study on cleaner fuel between UN and Ministry of Environment has been conducted.	
19.	The MOESD will soon come up with revised air quality guidelines. The consultant is advised to consider the new guidelines during their study	
20.	Any changes in the existing power plant (small or large) will require producing supplementary information or a revised revised EIA report for MOE approval and issuance of any license.	

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

STC (State Trading Corporation)

PARTICIPANT NAME & ORGANISATION	
CLIENT	CEB of Mauritius
PRESENT:	
S Sookhraz	CEB – Environmental officer
R K Dhununjoy	CEB - PE
James Swift	WorleyParsons - PE
Kajal Mukherjee	WorleyParsons – Power spec
M Bhatia	WorleyParsons – LNG spec
R Gungoosingh	SJP
C Cantelmo	WorleyParsons - PMT
John Stavers	Independent consultant
B. Asyrigadoo	STC – Commercial analyst
S Bissessur	STC – Commercial analyst
M Pillay	STC – General manager
CK Chooramun	STC – Commercial analyst
APOLOGIES:	

DATE	5 December 2013
TIME START	1:30pm SA time
TIME FINISH	3:30pm SA time
LOCATION	STC office
RECORDER	James Swift

RECORD OF DISCUSSIONS

ITEM	ITEM DETAILS	ACTION
1.	STC, trading arm of Government, is responsible for importation of strategic commodities such as petroleum products including LPG	
2.		
3.		
4.	1.2 – 1.3 Million tons hydrocarbons imported (7 types) a. Local consumption = 700 tons – 750 tons b. Balance is export and bunkering and supplying airlines serving Mauritius.	
5.	No refinery in Mauritius: a. import specifically from India (Mangalore) – only 6 days from Mauritius – offer whole range of products including: 2500 ppm sulfur diesel – marine; 50 ppm sulfur diesel – automotive b. Receive all products on dedicated vessel 64 000 t per voyage. (22 days turnaround – (6 trips); supplement with shipments as required. c. Also import 65,000 – 67,000t LPG: LPG – cooking & heating d. LPG is heavily subsidized – sell at half the price that it is imported. Buy at 676 MUR per 12 kg; sell at 330 MUR per 12 kg. (only for domestic use). e. LPG Autogas has not taken off in Mauritius despite the selling price (Rs 33.40 / litre) being exempt from Excise duty and other taxes. Actually with LPG being some 30% less efficient than petrol / litre this could be a significant reason for a slow adoption of this new auto fuel.	
6. 7.	STC handed over booklet that explains taxes applicable to fuel for automotive industry. Gasoline and Gasoil In short: Taxes: excise duty, sales tax, road development levy; MID (sustainable Mauritius) Levy, to subsidize LPG and rice and flour. Amount to 42 – 45% of price of automotive fuel. i.e. unloaded 25 MUR/l and sales price 50 MUR / liter.	
8.	Distributors of automotive fuel: Shell, Vivo, Indian Oil, Engen – they then distribute through 140 filling stations	
9.	Only 2 Companies distribute LPG to public.	
10.	For automotive fuel –price stabilization mechanism is in place to reduce the number of price changes per year.Prices are review at least once every 4 months and a formula exists (fully described in the booklet) to determine when pump prices must rise or fall. A Price Stabilisation Account receives credits when oil prices go down and funds subsidies when oil prices increase. The result of this new system has been very stable pump prices since January 2011.	
11.	LPG only carries 15% VAT. The subsidizing was due to it's less hazard nature compared to kerosene and being a clean fuel. Being a strategic product for government, LPG is heavily subsidized – it is used for cooking in 98% of all homes. Quite often domestic LPG is sold at cost less 25%, in December this year it is being sold at cost less 50%!	
12.	Not really considering LNG for domestic use i.e. piped to homes. People too dispersed. Cost of piped network would be prohibitive.	

ITEM	ITEM DETAILS	ACTION
13.	Statistics for size of industry – MEXA (Mauritius export association – Danielle Wong.). also consult Mauritius statistics office	
14.	A 2nd Part was considered (south east) to diversify fuel storage locations. Currently it is all kept on Port Louis; security risk.	
15.	Policy decision of Government - make Mauritius a regional hub for petroleum products.	
16.	Bunkering might be an option. Will allow private oil companies in future to import and sell for bunkering. (31,000 ships pass by near Mauritius en route to/ from South America- India China via CAPE route, 700 stop for fuel, 1000 stop for armed guard change). At present most vessels go to Durban for refuelling.	

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Ministry of Housing & Lands

PARTICIPANT NAME & ORGANISATION	
CLIENT	CEB of Mauritius
PRESENT:	
Ms Ujoodha	MHL
Mr N Seenauth	MHL
Mrs Jhummun	MHL
Mr V Rugbur	MHL
Mr Rambarassah	MHL
Mr Jugoo	MHL
Mr M Bhatia	WorleyParsons
Mr K Mukherjee	WorleyParsons
C Cantelmo	WorleyParsons
J Swift	WorleyParsons
APOLOGIES:	

DATE	6 December 2013
TIME START	9:30am SA time
TIME FINISH	11:00am SA time
LOCATION	MHL office, 6th floor, Cyber city, Ebene
RECORDER	James Swift

RECORD OF DISCUSSIONS

General discussions were held around the requirements and role of the Ministry of Environment and Sustainable Development to inform the team appointed by CEB for the study as noted above. The main points relevant to the study are noted below.

ITEM	ITEM DETAILS	ACTION
1.	The MHL do not have detailed zoning map. They have broad map, but approvals for zoning really developed by policy documents. Mauritius has 4 Towns and 1 city (Port Louis) – have outline planning schemes for each town& city. Furthermore, district planning schemes exist.	
2.	All development planning done by Ministry of Housing & Land.	
3.	District schemes – still have opportunity for development – can be obtained from website of MHL & can be obtained from 5th Floor MrGoolamhossen	
4.	Urban schemes being revised at present	
5.	Protected areas – 2 marine areas: a. Balaclava marine park b. Blue bay marine park Also get information from Ministry of Fisheries.	
6.	Government owns less than 20% land / half of it is forest and protected. i.e. Most land is in private ownership.	
7.	South site at old port (Bois des Amourettes): has been used during WWII a. Petroleum storage tanks. b. Defense land under control of Prime Minister Office	
8.	Jin Fei: Land is leased; government cannot take it back. Jin Fei can be sub-leased. Probably for not suitable for power plant – residential issues. Power plant buffer 1 km.	
9.	Alternative site was suggested: State land acquired for sewage treatment plant. Mt Jacquot. Already have 400 m buffer with a 200 metre notification zone and another inner 200metre exclusion zone for sensitive (residential, school, health) uses	

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Wrap-up Meeting

PARTICIPANT NAME & ORGANISATION		
CLIENT		CEB of Mauritius
PRESENT:		
R. Dhununjoy	: CEB	Project Engineer
D. B. Seblin	: CEB	Mech. Eng. Fort Victoria
S. Sookhraz	: CEB	Environmental Officer
M. S. Mukoon	: CEB	Corporate Planning and Research Manager
James Swift	: WorleyParsons	Project Engineer
K. Mukherjee	: WorleyParsons	Power Specialist
M. Bhatia	: WorleyParsons	LNG Specialist
Clemente Cantelmo	: WorleyParsons	Marine Eng.
John Stavers	: Consultant	Transport Engineer
APOLOGIES:		

DATE	6 December 2013
TIME START	3:30pm SA time
TIME FINISH	5:00pm SA time
LOCATION	Fort Victoria Station
RECORDER	James Swift

RECORD OF DISCUSSIONS

ITEM	ITEM DETAILS	ACTION
1.	Kajal ask about 1 km exclusion zone from power plant. Mr. Mukoon states that it as long as the power plant is respecting all the environmental norms, it is not necessary to keep a radius distance of 1 km from the power plant.	
2.	Bhatia – discuss the options available for LNG based on his initial thoughts after visit to sites and discussions with some stakeholders: a. Suggest onshore storage and regas b. For planned HFO tanks – already designed: size fixed, but configuration can still be altered. (Keep to NFPA 30).	Rakesh will send final layout drawing of HFO tanks
3.	Kajal – Discuss the various options and configurations available for Power generation technology based on his thoughts after the Mauritius visit. a. Suggest that three options will be considered in screening including 2 GT configurations and possibly consider a reciprocating engine. This will be expanded on in the Inception Report.	
4.	Switch yard for new power station – preferably on site. Generator 11 kV. Then have transformer from 11kV to 132 kV. Underground cables most likely to be used.	
5.	We discuss bunkering – will in high level explore this – might be required to reach critical mass.	
6.	Rough estimates mentioned by Mr. Mukoon: 100 USD per ton for CT Power coal, 650 USD per ton for HFO.	
7.	Can use in-house WP format for deliverable reports.	
8.	Monthly report from WP for progress is acceptable to CEB	
9.	May mention CEB name when speaking to OEM's.	
10.	Mr Mukoon suggested that the proposed electric propelled light railway system, proposed to run initially between Curepipe and Port Louis, would create an additional power demand. It is believed that the Government will be floating a tender as early as 2014	
11.	James mentions that a discussion is required on the tax interpretation. WP has based its pricing on certain interpretation of the tax requirements; most notably TDS and VAT. WP has noted the tax agreement between Mauritius and SA and has also applied this to our pricing.	It is required that a first invoice be send to CEB to test interpretation of tax. CEB agreed to allow further discussion to avoid any confusion at a later stage.
12.	Mr Mukoon suggested that the Medine site could be considered for setting up of 100 MW CCGT plant should any fatal flaw be identified during the Pre-feasibility study by WorleyParsons. If viable, CEB may acquire land thru' compulsory acquisition. From the site visit by WorleyParsons, however, there is not an apparent fatal flaw at this stage and focus will be placed on analyzing the Les Saline site in more detail for this study.	

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MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Site visit notes

PARTICIPANT NAME & ORGANISATION		**DATE**	4,5,6 December 2013
CLIENT	CEB of Mauritius	**TIME START**	various
		TIME FINISH	various
		LOCATION	various
		RECORDER	James Swift

RECORD OF DISCUSSIONS

Dec. 5th St. Louis Power Station

1. Old Pielstick Power House (units 5 and 6) will be demolished and a new power house shall be constructed to house 4x15 MW new Dual fuel (LNG and HFO 180 Cst) medium speed diesel engines
2. Existing plants have Pielstick and Wartsila Engines.??
3. 24 000 hours Maintenance cost is 18 million Rs. and require about 1.5 months .
4. 12000 hours maintenance cost about 3 million Rs and takes about 3 weeks .

Dec. 5th Fort Victoria Power Station

1. 6x15 MW HFO/Distillate fired power plant (Wartsilla – 2012). Fuel consumption 202 gm/KWh
2. 2x8.5 MW HFO/Distillate fired power plant (MAN – 1990). Fuel Consumption 213 gm/kWhr.
3. Capacity for Wartsila dispatched at 12 MW but no less than 10 MW for efficiency reason.
4. Wartsila units can be operated at night while MAN units typically start in the morning (0600) and turned off at night.
5. CEB Will provide the O&M costs. (provided)

Dec. 5th Tank Farm Visit (Fort William)

1. There are 2 x 6000m3 and 1x 5000 tanks to support the needs for Fort Victoria and Saint Louis
5. Saint Louis and Fort Victoria uses 180 cst HFO. Fort Georges uses 380 cst HFO.

Dec. 5th Les Salines Site visit

~~1.~~ CEB is planning to install 6 tanks each of 5,500 m3 at this site.
2. The new tank farm would support the needs of additional 4 x 15 MW HFO power plant at Saint Louis and also support the fuel requirement for the Rodrigues Island.
3. The site looks good for the power plant and also considering the proximity of the LNG tanker jetty.

Dec. 6th Old Port Site Visit

1. The existing jetty is very small, the water depth seems very shallow (based on the color of water) and would require a significant rework for any new LNG import facility.
2. The existing old oil tanks (from Second World War era) are located on the hill side. The tank walls are collapsed and the site will require significant earthwork and demolition for any new power plant.
3. There are many residential areas close by. The area is very scenic with a lot of vegetation and flowers. A new power plant in the area will have significant impact on all these.
4. There are hardly any industries or any major load center and there does not seem to be any HV transmission line close by.
5. Considering all the above, the site did not seem to be a good location for the new power plant.

MEETING RECORD

Project No: 282570

Project: Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Automotive related visit notes

PARTICIPANT NAME & ORGANISATION		DATE	4,5,6 December 2013
CLIENT	CEB of Mauritius	TIME START	various
		TIME FINISH	various
		LOCATION	various
		RECORDER	John Stavers

RECORD OF DISCUSSIONS

Thursday 5th December

1. Rose Hill Transport

   a. We met with Balkrishoon Rajkoomar, Workshop Manager who was extremely helpful in providing information on the bus industry as a whole and Rose Hill Transport. He sits on various bus working groups on behalf of the Ministry of Transport.
   b. The company owns and operates 90 buses from it's depot in Rose Hill. 55 of the buses are Euro 0 emissions standards, 35 are Euro 2 (cleaner but far from the Euro 4/5 in Europe today). The depot appeared to be rather limited in space for additional refueling facilities but this would need to be thoroughly investigated.
   c. The fleet is probably the youngest fleet in Mauritius, average age 4.87 years. The regulations state that buses can operate to an age of 16 years and then up to 18 years provided a quarterly black smoke test is past on a quarterly basis. Rose Hill Transport does not keep buses for longer than 10 years maximum.
   d. Going forward the maximum age allowed prior to regular smoke tests may be reduced from 16-14 years and a Euro minimum emissions standard will be applied for new buses.
   e. Currently RHT are supplied with diesel from Shell via their local partners Vivo Energy. Shell provide the fuel storage and dispensing facilities under the terms of a 5 year contract.
   f. The Nationally controlled price of diesel to bus operators is retail price less Rs 4 / litre. (This was recently reduced from Rs 5-4). This increase in price, (for petrol and diesel) engineered by Government allowed them to offer subsidies to bus operators bringing in new semi low floor buses to the tune of Rs 1 million and VAT was waived.
   g. Prices (unsubsidized) of new buses are, on average ;-
      i. Chinese and Indian – Rs 4.5 million (US$ 150,000)
      ii. Japanese – Rs 8.5 million (US$ 280,000)
      iii. European (Mercedes) – Rs 11.0 million (US$ 367,000)

      The last 15 buses bought on tender came from Japan. Normally the buses are leased unless the company is cash rich at the time of the tender.
   h. In terms of diesel consumption, the fleet uses 4,000 litres of diesel Monday to Saturday and 1200 litres on Sundays. Typically buses drive 150-200 km / day. All refueling is carried out in a 3 hour window (5-8 pm) to avoid condensation forming in the tanks.
   i. In terms of fuel efficiency the buses operate at an efficiency of between 2.42 – 2.68 km / litre. The Euro 2 buses only achieve 2.2 km / litre. (John - as Euro standards drive down emissions for diesel buses fuel efficiency will reduce further and capital cost will increase).
   j. Note - The figures quoted do not add up and would need re-confirming
   k. When vacant bus lines become available operators bid for the line and the National Transport authority will award the line based on the quality of the buses offered, the number of "back up" buses available in the fleet, the companies cash flows, emissions etc. No guarantees are made in terms of passenger numbers / revenues to be earnt, this is the bidder's risk.
   l. It was confirmed that the other bus operators are ;-
      i. National Transport Corporation 500 buses
      ii. United Bus Service 300 buses

iii. Triolet Bus Service 175 buses
iv. Rose Hill 90 buses
v. Individual operators 835 buses (operate in cooperatives, using public stations for refueling)
vi. Total 1,900 buses

m. Mr Rajkoomar stated that by 2015, 15 ppm diesel was anticipated to replace today's 50 ppm product
n. I viewed a new Yotong (Chinese) bus just purchased with semi low floor, air conditioning, DVD and wi-fi facilities. For this type of "executive" bus operators are allowed to charge an additional Rs 6 over and above the standard bus fare.

2. Government Mechanical Workshop

   a. This department coordinates the procurement and maintenance of all central government fleets. This includes for all Ministries and many of the departments, but excluding CEB (as an example) and Local Government fleets
   b. The department is responsible for 4,000 vehicles of which 1,500 are owned by the Police department. The police vehicles operate 24/7 and they are high fuel consumers.
   c. Most of the remaining vehicles were considered to be "low mileage" and therefore not suitable for gas in the opinion of the engineer we met. Typically the average annual mileage could be 15-20,000 km.
   d. All government vehicles use public refueling stations under the terms of a contract. A discount applies but smaller than the Rs4 discount enjoyed by the bus companies.
   e. Due to the lack of funds vehicles should be replaced every 7 years (light vehicles) or 10 years (heavy duty vehicles but it is not uncommon for vehicles to be 15-20 years old.
   f. The government procures (with cash) approximately 200 vehicles a year. (consistent with a 20 year average life)

Friday 6th December

1. National Transport Authority
   a. We were given some data on the public bus service
   b. We were provided with a copy of "Digest of Road Transport and Road Accident Statistics 2012" document which sets out an analysis of the vehicle population of Mauritius.
   c. Regarding taxis there are some 6,900 registered, mostly owned by single individuals and fairly low fuel consuming (we met 2 taxi drivers later that suggested typical monthly mileages of 2-3,000 km).
   d. Taxis do NOT receive discount on fuel like the bus companies but they do get an 80% discount on duty paid on imported vehicles (typically 80% but to be confirmed by Ministry of Finance)
   e. The NTA administers annual road tax and car registration fees

2. National Transport Corporation
   a. NTC is the state run bus company and appears to be contracting from 600 buses previously to 502 at present
   b. The HQ and largest depot is in Vacaos
   c. Approximate number of buses per depot ;-

i. Vacaos 200
ii. Forest Side (nr Curepipe) 85
iii. Riviere du Rempart 65-70
iv. Point Aux Sables 78 (65 run daily)
v. Soullac 65

d. We visited Vacaos and Point Aux Sables, the former having ample space for refueling equipment, the latter less so.
e. We met the site manager for the Point Aux Sables site, he confirmed but asked for confidentiality ;-
    i. His site uses 5000 litres diesel daily
    ii. The buses refuel between 4 – 9 pm
    iii. His buses drive 12-13,000 km daily which suggests a fuel efficiency on average of 2.4-2.6 km per litre – these fuel consumption figures DO add up
    iv. Due to lack of funds NTC are forced to operate their buses until the 18 year limit
    v. When the company procures it relies on bank financing
    vi. The fuel contract is re-tendered annually
    vii. The company does not have a preferred bus supplier, this is decided upon depending on the outcome of each tender

3. United Bus Company
    a. We met Sakeer Farad, Assistant Workshop Manager at the Port Louis depot
    b. The company, privately owned, owns 315 buses, 50% based at the Camp Chapeon, Port Louis depot and 50% at the Seizeme Mille depot close to the highway south of Curepipe
    c. Buses are kept for 15-18 years
    d. We were advised that imported buses are exempt of duty
    e. The recently preferred supplier has been Tata of India, and the company now buys Euro 2 models, usually high floor
    f. The vehicles are re-fuelled between 5.00-9.30 pm
    g. It was stated that the buses drive, on average, 8000 – 8500 km per month
    h. The Port Louis site uses 6,000 litres / day, 7 days a week
    i. Fuel efficiencies vary, with the average being in the order of 2.5 km / litre
    j. These fuel consumption figures no not add up, further checking needed
    k. Engen is the fuel supplier, the contract is re tendered annually
    l. Tata has been the preferred supplier recently, the company pays in cash

4. Triolet Bus Service, Triolet
    a. We drove past this site, all 175 Triolet buses are based here and there appears ample space for additional refueling facilities.

5. Other miscellaneous information gathered
    a. Current pump prices ;-
        i. Petrol Rs52.25
        ii. Diesel Rs43.95
    b. The recent budget speech set out the government's policy on road transportation fuel pricing
    c. Industrialists are complaining about the price of LPG and electricity and are asking for alternatives

d. Crematoriam incinerators are a big load, currently using LPG. Textile factories could also be an industrial target for gas. Plus breweries, e.g. Phoenix Brewary based in Phoenix
e. Data on the fuels used in industry could be found from Mauritius Export Authority or the Central Statistics Office
f. A key target in the transportation sector could be the tourism transit vehicles, operating daily from the airport. There are 4 large companies, White Send Tours, Solis, Summertime Tours and Mauri Tours. Fuel consumption of these vehicles would be significant. Plus car rental companies.
g. Most bus bodies are produced in Mauritius by companies such as ABC Coachworks and Procoach
    h. In terms of maximum weights allowed for trucks, it appears that a maximum load of 10 tonnes per axle applies and there is no maximum load per vehicle per se.

Appendix B - Annotated DIR

Note that it has not been confirmed that all notes below stating "– See files uploaded to SharePoint" indeed have been sufficiently supplied. This needs to be confirmed by whoever requested the information by looking at what has been supplied.

Existing Reports

Provide existing reports addressing the following:

1. Electricity Demand Forecasts for Mauritius
   - IEP 2013-2022
2. CEB Generation Development Plans and Planned Additions
   - IEP 2013-2022, 100MW (2x50MW) – CT power, see IEP p53 (2017). CFBC technology; Installation of 4x15MW HFO engines also planned, ST Louis Power station (end 2015). 65MW RE energy projects including wind (40MW) and solar (25MW) – Mid 2015.
3. Grid Stability Studies to determine the maximum generation unit size at specific locations.
   Equivalent to 10% of peak demand – around 50MW
4. LNG use and demand forecasts in generation, industrial & residential use and transportation sectors.
   – None available
5. Proposed distribution map including right of ways of vaporized gas pipelines.
   Could possibly use current HFO pipeline right of ways for gas pipelines. Around 5 to 10km from port. Pipes possibly for PP and road transport for others?
6. Environmental assessment study at existing generation facilities.
   See files uploaded to SharePoint

Current Generation assets and site related information

1. Provide a list showing the type of prime movers, installation date, fuel type, rated capacity and heat rate each at each location.
   Rakesh will provide all info for CEB plants; IPP plants are normally using bagasse / coal (they are not efficient technology). EU standards have been imposed on CT Power coal Plant project thus making the need to opt for a CFBC technology plant. Do not think the old IPP plants will be feasible to convert to comply. Maybe in 2018 and onwards it will not be decided to keep them running and maybe replace them with LNG CCGT's. However it seems at this stage not feasible to convert the IPP's. But, WP could look at what Critical mass is required and make recommendations around this issue. – See files uploaded to SharePoint
2. Provide a list showing the de-rated capacity and heat rate of existing generation assets at each site.
   – See files uploaded to SharePoint
3. Condition assessment report of existing fleet to include operational and maintenance issues and planned upgrades.
   Also see IEP. Further information required on O&M can be supplied by Mr. Bernard. – See files uploaded to SharePoint

4. Existing site drawings showing the power plant layout, laydown area, buildings and structures (electronic files preferred)
   – See files uploaded to SharePoint
5. Description of accessibility of site by transportation vehicles including weight and size limitations.
   – See files uploaded to SharePoint
6. Fuel Supply arrangement (Primary and Secondary, if required) and operating details (pressure, temperature and quantity).
   – See files uploaded to SharePoint
7. Grid Capacity limitations, if any
   – IEP; also see unit size limitation noted above
8. Plant Water Supply arrangement, operating details and quantity limitations, if any
   – See files uploaded to SharePoint
9. Site specific issues, if any, concerning noise, emissions waste, thermal discharge and such matters.
   – See files uploaded to SharePoint.

Heat balance related details – Each site – See files uploaded to SharePoint

1. Ambient Temp (Max, Min and Design) with coincident Relative Humidity Data
2. Site Elevation above MSL
3. Primary fuel analysis and available quantity details.
4. Secondary or Back Up fuel analysis, available quantity, pressure and temperature details.
5. Plant make up water analysis.
6. Plant Cooling System Configuration (Air cooled, Once Thru', Cooling Tower)
7. Any special site specific issue (please identify)

Emission data and permit limits – each site. – See files uploaded to SharePoint. Mr. Sookhraz will supply applicable regulations. Will also supply excel table with emissions evaluation for existing sites and try and get data for water emissions.

Provide the following Emission data for the existing plant as well as for the proposed new Plant

1. Governing Regulation
2. Steady State Emission Limits for each criteria pollutant NOx, Sox, CO, VOC & PM (ppmvd and TPY)
3. Waste Water Discharge Permit Limits
4. Zero Liquid Discharge Requirements
5. Cooling System Return Permit Limits (Once Thru' System only)

Plant Operating Profile – each site IEP to be consulted;

Provide the current and planned operating profile data for generation plant

1. Typical Daily and Weekly Operating Profile

– See files uploaded to SharePoint

2. Annual Base Load Capacity Factor
   IEP
3. Number of Annual Starts and Stops
   IEP gives general info; no specific start and stop records exist in CEB. Note: Only Fort George is base_load plant among CEB power plants. Rest of the plants (medium speed diesel) are started and stopped daily (7:00 – 21:30 roughly) –. Hydro units are dispatched where there is rainfall. Gas turbines operate as peaking units and under emergency conditions.

Plant Economic factors (Delete the ones that do not apply)

1. Plant Book Life, Yrs
   25 years CEB; 20 years IPP (PPA term)
2. Debt to Equity Ratio
   generally 70% loan, 30% equity
3. Discount Rate. % Pa
   8%
4. Fuel Cost, Primary Fuel ($/MMBtu-HHV) note 1
   HFO is primary fuel for diesel engine; GT's Kerosene; Purchase price per litre per consignment is available, but burner tip calcs are not done i.e. formulas not available.
5. Fuel Cost, Secondary Fuel ($/MMBtu-HHV) note 1
   Distillate (light fuel oil) is secondary fuel for diesel engines.
6. Electricity Selling Price, $/MWhr note 2
   No flow of CAPEX and OPEX to electricity price. Tariff is already established but any tariff increase should get Government's prior approval. Government acts as backup if CEB defaults on payments to IPP – an implementation agreement is signed between Govt and the developer.. Also see IEP.
7. Replacement Capacity Cost, $/kW
   2.8 billion MUR for 60MW (2012); 1.6 billion MUR for 30MW (2010) HFO engines.
8. Water Purchase Price, $/1000 gal
   CWA website
9. Waste Water Discharge Cost $/1000 gal
   No payment for waste water as long as you adhere to standards.

Note 1: Preferably actual pricing formulas for the various fuels used for power generation (need to understand current indexation) and what "adders" need to be included to come up with a burner tip cost of fuel. This will be needed to do an "apples to apples" comparison with burner tip LNG costs. Note 2: Information on how CAPEX and OPEX for new facilities (and for any repowering/modification to accommodate natural gas fuel) and the cost of fuel flow through the electricity price/rates.

10. General Escalation, % Per year
    – See files uploaded to SharePoint for 4 CEB plants
11. OPEX cost for current plants – See files uploaded to SharePoint y for 4 CEB plants

Data requirements for the transport sector assessment: This will be discussed with the National Transport Authority, Ministry of Environment, Ministry of housing and land and State Trade Corporation. See respective minutes.

1. Basic data on the number and type of vehicles registered and used in country, by location if available. Vehicle age and typical annual mileages.
2. Pricing data and an understanding of how petrol and diesel are marketed in country. Who are the key players and could these companies be considered partners or competitors as NGVs were introduced? Are all liquid fuels imported or are there refinery facilities in country? Are there any other fuels used in country, for example LPG?
3. Government policies / taxation on motor fuel.
4. Government policies / taxation on environmentally friendly fuels in general. How concerned is Government on the issues of greenhouse gas emissions and the emission of more toxic pollutants and the impact that this has on public health? (Respiratory and heart related illnesses). Have policies already been introduced in country that is positive toward clean fuels?
5. Meetings with key fleet owners to gather fleet data and attitudes towards the possible introduction of a clean fuel alternative and their vehicle replacement policies. Key fleets would include taxis, buses, government (including Municipality) fleets, airport and port based fleets, the CEB fleet, key truck / tourist bus companies.
6. A tour of the island to understand the geography of a possible gas refuelling network.
7. Economic data for scoping economics, including the cost to buy or rent commercial land, the availability and cost of electricity, labour rates for pump attendants, drivers and more skilled motor mechanics, engineers, and basic building costs.
8. The licensing process that would apply to the approval of compressed natural gas refuelling facilities and the conversion of vehicles to operate on CNG.
9. Details of the concept study performed on the opportunity
10. Mauritius long term macro-economic forecasts for the next 20 years
11. Details of any regulator related costs / information relating to the Energy Projects in Mauritius
12. Any Government limitations to procuring long term PPAs (guarantees, term, escalation pricing)
13. Specific Mauritius taxes or non-operational costs that need to be considered (e.g. labour levies, royalties etc)
14. Specific tax treatment of capex for Energy Projects in Mauritius

Data requirements for the Port and Marine assessment: This will be discussed with the Mauritius Port Authority, Ministry of Environment, Ministry of housing and land and State Trade Corporation. See respective minutes.

1. Applicable risk assessment studies and available records of climate and geo-hazard related activities in the area object of study
2. Applicable geological and geotechnical information
3. Development Master Plans and operational information for existing port facilities in the proximity of the area object of study (Port handbook, current port traffic, future growth predictions and details of any vessels using the port, including types, lengths, beam, draft, displacement)
4. Admiralty charts
5. Historical studies and reports, design, as-constructed drawings of existing coastal and marine structures and previous condition assessments of coastal and marine structures in the proximity of the of the area object of study
6. Previous surveys (bathymetric, topographical, geotechnical, geophysical)
7. Maintenance dredging regimes and records
8. Metocean data (wave, wind, tides, currents, cyclones)

Data Requirements General

1. Fiscal regime for investments made by CEB and for investments made by private investors in the power generation sector (e.g. IPP) – tax rate(s), depreciation schedules, allowed tax deductions, etc.
   This is best discussed with the Ministry of Economic Development and Finance. Note that time did not allow for a visit to be arranged. Consult website: http://mof.gov.mu/English/Pages/default.aspx.
2. Fiscal regime for investments made by a State company for fuel infrastructure (i.e. LNG infrastructure) and for investments made by private investors for the LNG infrastructure – tax rates, depreciation schedules, allowed tax deductions, etc.
   This is best discussed with the STC (see respective minutes) and Ministry of Economic Development and Finance. Note that time did not allow for a visit to be arranged. Consult website: http://mof.gov.mu/English/Pages/default.aspx.
3. Carbon tax and subsidies due to environmental reasons for LNG fuel use?
   See minutes from STC discussion.
4. Fuel oil import and storage infrastructure. Who owns and operates it and how those costs are reflected in the cost of fuel oil at "the burner tip".
   State trading corporation. See minutes from the STC discussion. – See files uploaded to SharePoint y for 4 CEB plants
5. Desired/required minimum fuel inventory requirements (in days of consumption).
   State trading corporation. See minutes from the STC discussion. – See files uploaded to SharePoint y for 4 CEB plants

6. Who will be leading the project if the conversion of LNG goes ahead? CEB or government?
   Note sure who will lead this; it is thought that CEB may acquire the capability to operate an LNG facility (Mr. Mukoon stated the need for capability building fi this route is to be followed) and then to distribute to the transport sector also. STC also shows interest.

Appendix C – Register of documents received from CEB

Nr	Folder	File Name	Document Title	Doc No	Date Issued	Document Type	Date WP Received
1	Environmental info/EIA reports	EAI redevelopment 2012	St Louis power station redevelopment Environmental Impact assessment		July 2012	Pdf	7 Dec 2013
2		Fort Victoria EIA Addendum Final report	Fort Victoria power station Environmental Impact assessment addendum		Febr 2010	Pdf	7 Dec 2013
3	Environmental info/Environment documents	Air	Legal supplement The environment protection act 1991		29 Aug 1998	Word	7 Dec 2013
4		Bill2408	The utility regulatory authority (amendment) bill		No XXIV of 2008	Pdf	7 Dec 2013
5		Bussiness facilitation Act	The business facilitation act 2006 Act no. 21 of 2006		31 Aug 2006	Pdf	7 Dec 2013
6		CDMReg	Legal supplement Government notice No 74 or 2010		27 March 2010	Pdf	7 Dec 2013
7		Central Electric Board act	Central Electric Board Act 32 of 1963 – 25 Jan 1964			Pdf	7 Dec 2013
8		Copy of 5 emission standards	Emission standards for EPA			Word	7 Dec 2013
9		Effluent discharge registration in ocean	The environment protection act 2002		Government notice no 45 of 2003	Word	7 Dec 2013
10		Effocean	The environment protection act 2002		Government notice no. 45 of 2003	Word	7 Dec 2013
11		Environment protection (amendment of schedule) regulation 2006	The environment protection act 2002		Government notice no 142 of 2006	Pdf	7 Dec 2013
12		Environment standard for noise	The environment protection act 2002		Government notice 115 of 2003	Word	7 Dec 2013
13		Environmental Standards for Noise regulations	The environment protection act 1991		11 July 2002	Word	7 Dec 2013
14		Epaprintable	The environment protection act of 2002		Act no. 19 of 2002	Pdf	7 Dec 2013
15		Ile	Maurice ile durable final			Jpeg	7 Dec 2013
16		Ilereg08	Finance & audit act			Jpeg	7 Dec 2013
17	MID Final report	1.cover final (2)	Maurice ile durable Policy strategy/Action plan		May 2013	Jpeg	7 Dec 2013

Nr	Folder	File Name	Document Title	Doc No	Date Issued	Document Type	Date WP Received
18		Table of contents	Maurice Ile Durable policy, strategy & action plan Final report		May 2013	Word	7 Dec 2013
19		Executive summary	MID goals & target			Word	7 Dec 2013
20		4.Introduction to measuring progress	Introduction to Maurice Ile Durable			Word	7 Dec 2013
21		University tests on air quality	Air Quality Test on thermal power station of the CEB- Conducted by the University of Mauritius			Excel	7 Dec 2013
22	LNG Project – Production/Cost	Data requirements for LNG	CEB – Fuel cost/ Opex cost for current plants/Escalation % per year			Excel	7 Dec 2013
23		Records of HFO180 CST	CEB – Heavy fuel oil 180 CST Fort Victoria & St Louis Power station 2007 - 2013			Excel	7 Dec 2013
24		Record of HFO380 CST	CEB : Cost of 380 CST Fort George Power station 2005 - 2013			Excel	7 Dec 2013
25	LNG Project Production/Fort George Power station	Cooling water arrangements	DE3 Cold water system			Jpeg	7 Dec 2013
26		Cooling water arrangements (2)	DE3 Jacket water			Jpeg	7 Dec 2013
27		Fort George Power station module	Fort George power station			Word	7 Dec 2013
28		Fuel system	DE3 Fuel oil			Jpeg	7 Dec 2013
29		Site layout fgps				Jpeg	7 Dec 2013
30	LNG Project Production/ Fort Victoria	2003.D2.011	As built			Pdf	7 Dec 2013
31		Appendix F Data requirements LNG responsibility	Appendix F : Services & Facilities provided by the Client			Word	7 Dec 2013
32		Book 1				Excel	7 Dec 2013
33		Cooling water arrangements	DE3 Cold water system			Jpeg	7 Dec 2013
34		Cooling water arrangements (2)	DE3 jacket water			Jpeg	7 Dec 2013
35		Fuel system	DE3 Fuel oil			Jpeg	7 Dec 2013
36		Newdoc 9	Heavy fuel specification			Pdf	7 Dec 2013
37		Newdoc10	Analysis of make-up water supply			Pdf	7 Dec 2013
38		Site layout fgps				Jpeg	7 Dec 2013

Nr	Folder	File Name	Document Title	Doc No	Date Issued	Document Type	Date WP Received
39	LNG Project Production/ Nicolay Power station	Annex 1 Extract Final report PB power	Final report Assessment of existing power plants in Mauritius			Pdf	7 Dec 2013
40		Annexure 2 Nicolay PS layout				Pdf	7 Dec 2013
41		Annexure 3 JET A1 Fuel specification	Manadore refinery & petrochemicals limited Quality certificate			Pdf	7 Dec 2013
42		NIC data input	Current generation assets & site related info			Excel	7 Dec 2013
43	LNG Project Production/Saint Louis	Appendix F Data requirements L NG	Appendix F Services & facilities provided by the client			Word	7 Dec 2013
44		SL layout	St Louis Power station layout			Pdf	7 Dec 2013
45		St Louis PS layout updated				Autodesk design	7 Dec 2013
46	System control/Summer week Profile	Generation 15 Nov 2013/ 16 Nov 2013/17 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
47		Generation 18 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
48		Generation 19 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
49		Generation 20 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
50		Generation 21 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
51		Generation 22 Nov 2013/ 23 Nov 2013/ 24 Nov 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation			Excel	7 Dec 2013

Nr	Folder	File Name	Document Title	Doc No	Date Issued	Document Type	Date WP Received
			statement/Load Req IPP/Load req CPP				
52	System control/Winter week profile	Generation 01 June 2013/ 02 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
53		Generation03 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
54		Generation 04 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
55		Generation 05 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
56		Generation 06 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
57		Generation 08 June/09 June 2013/ 07 June 2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
58		06Feb2013	Generation/CPP/Prodcurv/IPP-CPP/Ipp/Major events/Plant availability/Generation statement/Load Req IPP/Load req CPP			Excel	7 Dec 2013
59		Final report PB power April 03	Audit of optimal generation capacity in Mauritius		April 2003	Pdf	7 Dec 2013
60		Gasoline and gas oil pricing	STC			Pdf	7 Dec 2013
61		IEP2013-2022	Integrated Electricity Plan			Pdf	7 Dec 2013

Nr	Folder	File Name	Document Title	Doc No	Date Issued	Document Type	Date WP Received
62		University tests on air quality	Results for Ambient Air quality (24 hour average)			Excel	7 Dec 2013

Appendix D – Refined methodology document

2.2 (Section 2: i) Assess HFO conversion to LNG:

~~Upon receipt of the information in the Data and Information Requirements (DIR) document, t~~The Consultant will initiate dialogues with the OEMs and/or aftermarket service groups to define the specific requirements for each type of prime mover. Per discussions with CEB at the KO meeting, we will keep the OEM's informed of the project details to get faster and more interactive responses. T~~t~~he Consultant will develop a summary screening table with the salient details of each prime movers, identify the changes needed based on discussions with OEMs and provide a recommendation if it would be feasible/worthwhile to consider particular prime mover for the conversion process. The Consultant will also provide a recommendation on the path forward (replacement with similar type or changing type of prime mover) for those prime movers that are deemed not suitable for the conversion.

2.3 (Section 2: ii) Cost estimate of HFO to LNG conversion:

The Consultant will develop the cost associated for conversion of the applicable primemovers. The Consultant will solicit inputs from the OEMs for the cost associated with the conversion, develop the Balance Of Plant (BOP) system changes and associated costs based on in-house data base and integrate them all to develop the overall cost for each primemover and each site associated with the conversion. A separate cost estimate will be developed for replacement of the primemovers that are not suitable for such conversion. These costs will be integrated into the overall cost estimate for this study.

2.4 (Section 2: iv) Perform due diligence at Les Grandes Salines:

Being a relatively low lying site in close proximity to the sea the designated Grandes Salines site (Planning Division Drawing dated 05.12.2013, see below) is likely to be~~will need to be evaluated for vulnerability~~ vulnerable to coastal erosion and seawater inundation due to storm related waves and water level surge. This particularly applies to episodic cyclone events, which historically ~~has~~ have caused excessive onshore flooding in the area of the container terminal of Port Louis.

No detailed assessment of coastal flooding is proposed at this stage given the lack of baseline information, but any related threats posed for terminal functionality and safety will be highlighted when appraising the designated site. ~~The assessment will also consider climate change effects, including long term sea level rise.~~ Based on the review of existing documents such as demand forecasts, generation development plans, grid stability and such the Consultant will develop a screening matrix of the various options to support the 100 MW size LNG fired generation capacity addition~~CC plant~~. This would typically include the following:

- Identify technology and configuration options~~,~~ for Power Plant and Import LNG Terminal. Based on the discussions at the KO meeting with CEB it was agreed that the following technologies will be considered for the 100 MW generation capacity addition to capture the impact of relatively low capacity factor (Note: The prime mover capacity shall not exceed 50 MW),
  - One with Aero-derivative Gas Turbines based CC Project
  - One with Industrial Gas Turbines based CC project
  - One with multiple reciprocating engines (could have distillate support during LNG firing, if needed)

- Prepare preliminary heat balances / Performance data for the above three technology~~up to three CTG~~ configurations,
- Develop cost estimates in PEACE model for each of the above options
- Develop a table identifying salient prime mover~~gas turbine~~ attributes, overall plant performance, annual utility consumptions and generation, Capex, Opex and such parameters in support of the screening analysis.
- Perform screening analysis of options with recommendations for the optimum configuration based on the lowest life cycle cost

The Consultant will provide input on stakeholder engagement.

2.5 (Section 2: v) Identify other suitable sites:

As part of the due diligence exercise for the proposed Les Grandes Salines site, the Consultant also visited two other potential sites as proposed by CEB (JinFei - Baie de Tombeau /West coast & Old Port Site - Bois des Amourettes / East coast).~~will also investigate potential alternative sites for the power plant, storage tank locations and LNG unloading facility. The identification of possible alternatives will be based on a site visit and an initial list of key criteria to be developed with the Client at project inception.~~

~~The possible alternative sites will then be assessed and compared to the current proposed site with consideration of factors that may include but not be limited to:~~

~~Plant and storage spatial requirements including power plant;~~
~~Proximity to electrical transmission/distribution infrastructure;~~
~~Proximity to local residential/commercial/industrial developments;~~
~~Site accessibility and transport infrastructure;~~
~~Potential geographical, geological, geotechnical and environmental constraints;~~
~~Sensitivity to weather and metocean conditions, including cyclones and climate change;~~
~~Potential impacts of coastal processes, such as sediment transport, coastal erosion and flooding;~~
~~Port navigational, dredging, berthing and mooring and LNG offloading requirements;~~
~~Port operational requirements, including availability and proximity of tugs and work boats;~~
~~Potential routes and space for pipelines between berth, storage tanks and power plant;~~
~~Any land ownership issues;~~
~~Cooling Option. If the power plant is relatively far from the coast or if there are issues with respect to the use of ocean water, alternate cooling option will be evaluated~~
~~Comparative capital expenditure (CAPEX) and operational expenditure (OPEX) needs.~~

~~The assessment and comparison will be a high level exercise only, to confirm that the proposed Les Grandes Salines site is the most suitable location for the plant, or to identify the potential benefits of selecting an alternative location (e.g. increased plant capacity, better conditions for LNG vessel offloading). No plans or cost estimates would be prepared for any alternative locations as part of the scope of this pre-feasibility study. If an alternative site is identified as potentially preferable to the Les Grandes Salines site, the Consultant will communicate this to the Client at an appropriate stage~~

~~of the study and discuss the options for undertaking further work on the alternative including due diligence, cost estimation, implementation plan etc. as additional services under this contract or as part of a separate future study.~~

Based on the physical site visits and discussions with the Ministry of Environment and Ministry of Housing and Land, these alternate sites were deemed unsuitable (from first inspection) for a new power plant for the following reasons:

- JinFei - Baie de Tombeau:
    - The site is surrounded by residential areas
    - The site is located a relative distance from the shore line that would create some difficulties in LNG to Power Plant integration
    - Right of way would be an issue
    - The site is a special purpose zone. The property is leased to the Chinese government. The Chinese government can sub-lease it to others for similar usage as in the original lease but it can probably not be converted into an Industrial zone for Power Plant.
    - Since the site is surrounded by a residential zone it also requires special attention on what can be put at the site
- Old Port Site - Bois des Amourettes:
    - The existing jetty is small and the water depth shallow. It would require substantial rework for any new LNG import facility.
    - Based on discussions with the Ministry of Environment, the marine location has corals and Ministry of Fishery has special regulations on not damaging/ disturbing the corals.
    - The site near the old abandoned tank farm area is rather sloped and will require significant earthwork and demolition for any new power plant.
    - There are residential areas close by. The area is scenic with good vegetation and flowers. A new power plant in the area will require removing / relocation of the flora and would disturb the current environment.
    - There are hardly any industries or any major load centre and there does not seem to be suitable HV transmission lines close by.

The alternate sites were discussed with CEB during the Wrap up meeting on 06 Dec 2013 and it was agreed to only consider the Les Salines site for the new power plant.

For the Les Saline site, typical assessment criteria may be:

- Plant and storage spatial requirements including power plant;
- Proximity to electrical transmission/distribution infrastructure;
- Proximity to local residential/commercial/industrial developments;
- Site accessibility and transport infrastructure;
- Potential geographical, geological, geotechnical and environmental constraints;
- Sensitivity to weather and metocean conditions, including cyclones and climate change;
- Potential impacts of coastal processes, such as sediment transport, coastal erosion and flooding;

- Port navigational, dredging, LNCG draft, berthing and mooring and LNG offloading requirements;
- Port operational requirements, including availability and proximity to existing port infrastructure, interference with existing navigation routes and related disruption and safety issues;
- Potential Jetty Location; possible routes and space for pipelines between berth, storage tanks and power plant;
- Any land ownership issues;
- Cooling Option. If the power plant is relatively far from the coast or if there are issues with respect to the use of ocean water, alternate cooling option will be evaluated
- Comparative capital expenditure (CAPEX) and operational expenditure (OPEX) needs.

2.6 (Section 2: vi) Determine LNG import requirement:

This activity is related to the fuel requirements for the new gas-fired CCGT plant (tied to a projection of power demand) under some dispatch scenario plus any additional gas requirements needed to support the conversion of other HFO/Kerosene fired plants under a certain dispatch scenario and capacity converted. The Consultant, depending upon advice by Client whether the Power Plant is to be for base load operation or Peak Load operation, will develop a table summarizing the total LNG requirements (hourly/daily and annual) to support the power generation needs (both conversion and new plant) that would be used to develop the LNG import and storage logistics. The annual fuel consumption calculations will be based on a capacity factor assumption that will be discussed with the Client.

2.7 (Section 2: vii) Assess LNG supply opportunity for transport sector:

The Consultant's Automotive Engineer will estimate the potential size of the market for LNG/~~natural gas~~CNG in the transportation sector by leveraging lessons learnt from the development of natural gas vehicle markets in other countries.~~LNG transportation conversion studies that have been conducted for other markets in the region.~~ The Consultant will utilize the lessons learned in other countries ~~findings from those studies~~ on the feasibility ~~to~~ of converting various segments of the transportation market (e.g., passenger vehicle, public transportation/busses, light and medium trucks and heavy trucks). Based on this information The Automotive Engineer will ~~to estimate~~estimate, assuming differing levels of market penetration, the long term (15 year) ~~the maximum~~ potential market build up for LNG in the transportation sector on the island of Mauritius. ~~The Consultant will then apply various conversion penetration scenarios to assess the incremental potential LNG demand that the transportation sector could generate in addition to the demand for LNG from the power sector.~~ In addition, the Consultant will provide estimates of demand build up that potentially could be generated in the manufacturing and commercial sectors~~may identify additional potential sources of LNG demand~~ that may warrant further evaluation should the transportation sector not be sufficient to achieve the anticipated critical mass for LNG demand in the island of Mauritius, i.e. There is a strong interface with the task "Assess whether LNG demand meets critical volume requirements".

Based on the data gathered in Mauritius and world-wide experience of natural gas market development, the Automotive Engineer will advise on the steps that would need to be taken to implement a long term programme of introducing natural gas as an alternative fuel in the road transport, manufacturing and commercial sectors. Guidance will also be provided on the time needed for each step to be undertaken.~~In more detail, the successful launching of a Natural Gas Vehicle market in Mauritius will depend on a number of factors and these will be researched during the study as follows:~~

For the transport sector

- An explanation will be provided on the pros and cons of LNG, LCNG and CNG re-fuelling options
- Alternative vehicle technologies will be briefly explained for both new vehicles and existing vehicles that could potentially be converted to use gas
- Guidance / justification on the niche fleets that could be initially targeted will be provided
- The importance of arriving at long term sustainable customer propositions will be explained and illustrated
- Guidance will be provided on how other governments have supported the successful introduction of natural gas vehicles through their tax regimes, plus the use of incentives and mandates and how such policies have been justified internally depending on the key drivers under consideration (e.g. environmental issues, public health, fuel diversity, reputational both internally and internationally)
- ~~Suitable niche vehicle sectors – taxis, government fleets, the Client's own fleet, public buses, tourist bus fleets, delivery tru~~A description of how LNG would be distributed by road from the import terminal facilities to vehicle re-fuelling stations will be provided, along with illustrations of LNG and LCNG stations layouts.~~Economics and high level design of necessary refuelling infrastructure – including the possible use of "virtual pipeline" solutions to refuelling points remote from the proposed gas pipeline network.~~
- The economics of this type of supply chain will depend on many factors (including but not restricted to the optimum type of fuel to be used by each vehicle type and the ultimate size and location of each refuelling station). However the Consultant will consider the necessary end user sales price of gas to be sufficiently competitive with diesel oil and gasoline and working back from this provide some initial guidance on whether, at this pre-feasibility stage, it would appear that a natural gas vehicle market could be economically developed with or without the intervention of Government subsidies. More accurate financial analysis could only be provided at a later stage based on a more comprehensive feasibility study.~~The customer proposition, how the cost of NGVs would compare with the cost of traditionally fuelled (diesel and petrol) vehicles. Other considerations could include the necessity for incentives from Government or whether NGVs could be launched economically without the need for incentives.~~
- ~~The degree by which Government will be committed to the successful introduction of NGVs, possibly motivated for environmental, fuel diversity or pure economic reasons.~~

Scoping economics will be undertaken to identify if the introduction of NGVs could be achieved without government incentives or whether these would be necessary to make the proposition sufficiently attractive to key fleet owners. ~~End user economics will be probably the most important factor.~~

~~Our Automotive Engineer will spend a total of 5 days in Mauritius, to attend the kick-off, site meetings, , stakeholder meetings and data gathering.~~

The Automotive Engineer's findings and recommendations will be based on the information gathered whilst in Mauritius and where the data was not available assumptions will be made based on experience gained in other countries.

For the manufacturing and commercial sectors: Based on sectorial energy data gathered in Mauritius the consultant will propose an aggressive and more conservative gas share scenario over a period of 15 years to establish potential LNG volume profiles.

The following assumption is made: The Consultant shall concentrate on potential larger scale clients from the road transport (refuelling stations), manufacturing and commercial sectors. Individual larger scale supply points can, subject to certain technical considerations, be fed via bulk supplies of LNG or alternatively CNG transported by truck from the proposed LNG receiving facilities or a closer by LNG / LCNG conversion station. Smaller scale clients cannot be fed, for safety reasons, via truck deliveries and bottles as is the case of LPG, they require comprehensive low pressure gas pipeline networks which are capital intensive, time consuming and logistically challenging to achieve.

In colder climates, as in Northern Europe, Russia and North America, low pressure pipeline networks can be economically justified due to the need for high energy consuming heating systems, as well as water heating and cooking. However in warmer climates when heating is seldom, if ever required, it is more difficult to justify investment in a house to house infrastructure network. Some warmer countries do provide some limited supplies of natural gas to residential areas in larger high density cities, but this does not help the economic case for the gas network, it is usually provided for political purposes.

This study will therefore assume that if gas is ever used in the residential sector this would be a second phase activity investigated once a "core" industry supplying larger scale power, manufacturing, commercial and road transport clients is up and running.

2.8 (Section 2: vii) Assess whether LNG demand meets critical mass requirements:

This is an economic assessment based on local LNG demand, which will be an output of the market study considering future national gas market expansion, opportunities for bunkering and spot cargo sales / bulk-breaking opportunities. By this stage of the study, several LNG demand scenarios will be in place involving various combinations and extents of:

- HFO/kerosene power plant conversion

- New CCGT power plant (100 MW or more suggested)
- Transport sector
- Any additional potential sources of LNG demand (scenarios to be available; developing further scenarios than described in scope above is not within the Consultant's scope)

The Consultant will compare and contrast the LNG demand scenarios with the expected minimum volume expectations of the potential LNG suppliers. These same LNG demand volume scenarios will be utilized in the Economic and financial modeling task, to estimate the potential impact of the transportation sector to improve "economies of scale" for the LNG import infrastructure.

2.9 (Section 2: iii) Investigate LNG supply countries and logistics:

To understand the factors that impact the availability and sources of supplies, the Consultant will establish some market context for the CEB. To achieve this objective, the Consultant will assess and describe the global market fundamentals based on proprietary Global LNG Supply Demand Model, and highlight the impact that may have on the availability and source of LNG supplies for the island of Mauritius.

- Global LNG Demand Supply Balance: Global LNG demand supply fundamentals are generally studied at a basin level (Atlantic, Middle-East and Pacific), although there is a strong inter-basin relationships exist between them owing to cross-basin flows. The Consultant will explore global LNG supply and demand trends, highlighting the estimated surplus/deficit in each of these basins based on our estimates of existing and upcoming liquefaction projects relative to demand. In particular, the Consultant will focus discussion on our latest view of Pacific Basin LNG supply-demand fundamentals out to 2025. As part of this analysis, the Consultant will identify the key competitor markets, e.g. in the Pacific Basin (Japan, S. Korea, China, India, etc.) over the relevant timeframe and their indicative uncontracted volume requirements.
- LNG Pricing and Alternative Gas Price Linkage: The LNG market has witnessed cyclical changes over the past few decades moving between buyers and seller's market. The Consultant will review various pricing mechanisms (Henry Hub, NBP, European hub and pipeline prices, JCC, LNG spot pricing).
  - The Consultant will provide CEB with the recent LNG pricing and estimates of the recent contracts in the market. Specifically, we will examine historic LNG pricing in the Atlantic and Pacific Basin, indexation levels, expected pricing trends in the future, and potential price drivers.
  - Based on the Consultant's assessment of Global supply-demand fundamentals, we will forecast the sort of price levels a buyer may achieve for long-term volumes between 2015 and 2020.
- Market Development: The Consultant will highlight the future LNG market trends both in the supply and demand side. Based on the market trends we will identify the potential impact this might have on the availability of LNG for the island of Mauritius.

Having set the market context, the Consultant will identify LNG export facilities that could potentially supply LNG to the CEB. Specifically, the Consultant will prepare a report that will provide the following information about prospective sources of LNG:

- Plant/project name
- Plant/project location
- Current status of the Plant/project (operational, under construction, under development)
- A map summarizing the information above
- Plant/project nameplate production capacity
- Plant/project sponsors
- Companies that are lifting LNG volumes from those projects
- Volumes of LNG that are anticipated to be available either because they are currently not committed to long-term contracts, or are anticipated to become available after the expiration of long-term contracts.

Based on the information above, the Consultant will identify specific companies that could potentially provide the LNG supplies to the CEB and what LNG export plants/projects such companies would source the LNG. The Consultant will estimate the transportation and delivery costs from such plants/projects to Mauritius. The Shipping Model will also be used to estimate the shipping capacity required to transport and deliver the required LNG volumes from such plant/projects to Mauritius. The Consultant will detail the results of this analysis in a section of the Study Report.

2.10 (Section 2: viii) Assess LNG supply availability to service Mauritius:

The scope of this activity will expand beyond the willingness and availability of ships to service the island of Mauritius and include the availability of supplies and the willingness of potential LNG suppliers to sell to new and smaller markets like the island of Mauritius. Given the current and expected future LNG market conditions, the CEB should expect that availability of LNG for its project will largely depend on the interest of potential suppliers to serve a new and smaller market like the island of Mauritius because LNG suppliers have traditionally focused their sales and marketing activities to larger LNG market such as Japan, South Korea, China, India, etc. Availability of ships is directly tied to supplies and is generally not considered a constraint for long-term supplies as new ships are built to support long-term trades.

The Consultant will leverage the results of Task 2.9 (see WBS), specifically the list of potential suppliers and transportation and delivery capacity requirements, to describe the general expectations of LNG suppliers in terms of LNG volume requirements, pricing expectations, and other key commercial considerations such as buyer's creditworthiness, and anticipated LNG volume demand volatility and flexibility requirements. The Consultant will evaluate how a potential LNG market on the island of Mauritius may match those supplier expectations.

2.11 (Section 2: ix) Assess port infrastructure for LNG import:

Following project inception the Consultant will build on its existing knowledge to further understand the conditions at the ~~port~~ Les Saline site and assess the constraints and opportunities presented by those conditions for the importation of LNG. The Consultant will achieve this through:

- ~~A~~ Considering the knowledge from the site visit ~~including~~ that included a preliminary visual inspection and high-level condition assessment of any relevant existing berth structures at Port Louis;
- Recalling / continuing the discussions with the Mauritius Port Authority (MPA) on current port traffic and future growth predictions at Port Louis and plans for future port expansion. Attempts will also be made to obtain information on existing coastal and marine structures, maintenance dredging regimes, details of vessels using the port (types, lengths, beam, draft, displacement) and weather interruption and possible repercussions on port operations~~High-level discussions with the Port Director, Port Engineer, Harbour Master and any other relevant port authorities;~~
- Recalling / continuing the high-level discussions with local authorities: The Ministry of Environment, The Ministry of Housing and Land and the State Trade Corporation on additional development constraints
- A desktop study of existing available information about the port as applicable~~,~~ and could ~~including~~include:
    - Development Master Plans for the port;
    - admiralty charts;
    - historical studies and reports;
    - design and as-constructed drawings of coastal and marine structures;
    - previous condition assessments of coastal and marine structures;
    - previous surveys (bathymetric, topographical, geotechnical, geophysical);
    - port handbook and operational information;
    - maintenance dredging regimes and records;
    - metocean data (wave, wind, tides, currents, cyclones);
    - current port traffic and future growth predictions;
    - details of vessels using the port (types, lengths, beam, draft, displacement);
    - Port land Reclamation Plans
- A desktop ~~review~~ assessment to the level suitable for a pre-feasibility study of metocean conditions based on the Consultant's existing local knowledge, any previous available studies and/or data collection and visual inspection during the site visit.

The above factors will be considered based on information that is already in the public domain, that can be visually determined during the site visits or that is provided by the Client at project inception. The Consultant will undertake a gap analysis of the existing available information to determine and advise further information that would be required for future studies and designs, including recommendations on how this information could be obtained.

Based on this understanding of the existing port and using information provided by other disciplines during the study, the Consultant will investigate the options for the delivery and offloading of LNG, considering factors that ~~may~~ will include ~~but not be limited to~~:

- Off- Shore (FSRU) or On-shore LNG Terminal
- LNG shipping and navigational constraints ~~(e.g. marine exclusion zones, governing wind and wave conditions, navigation channels and turning circles, typical tug and pilot requirements)~~
  - Marine exclusion area
  - Possible routes for navigation channels and turning circles
  - Preliminary assessment of required dredge depths
- The number and range of sizes of LNG vessels that would use the port, as determined by the studies to determine LNG import requirements, investigate LNG supply countries and logistics and assess LNG supply availability to service Mauritius~~;~~
- LNG vessel berthing and offloading options including LNG offloading plant and equipment, potential use of existing structures or the need to provide new berthing structures (this will include the needs of supporting tugs and work boats);
- An assessment of the requirements for any protective structures (e.g. breakwaters) to provide suitable safe berthing and unloading conditions;
- Environmental restrictions (e.g. proximity to protected areas and sensitive habitats and marine life).

The assessment will be based on the Consultant's knowledge of the industry and experience from similar international projects as well as industry standards and published codes and guidelines including:.

- BS EN 1473-2007 Installation and equipment for liquefied natural gas — Design of onshore installations
- Liquified Gas Handling Principles on Ships and in Terminals, 1995, SIGTTO
- PIANC guidance on channel design 1995 - Working Group 30

No metocean modeling, navigation or mooring studies, or any structural and geotechnical ~~would~~design, would be undertaken at this stage. The assessment of the port infrastructure will continue in parallel with~~, input into and reflect~~ the due diligence of the proposed Les Grandes Salines site ~~and investigation into possible alternative sites for the power plant~~.

~~The r~~Results ~~and recommendations~~ of ~~the~~ this assessment and recommendations on ~~of~~ the preliminary port infrastructure requirement will be presented in the pre-feasibility study report, with an outline layout drawing prepared to indicate the recommended options for the LNG import facilities (Off- Shore (FSRU) or On-shore LNG Terminal).

A high level discussion on potential benefits/limitations of a shore based rather than a floating storage and regasification option will be also included as part of the pre-feasibility study report.

Required inputs will also be prepared for the implementation plan and associated cost estimates relating to the Les Saline site.

2.12 (Section 2: x, xi) Determine LNG storage requirements and options:

Storage (and Regasification Facility) Site Selection; Review identified site options with respect to the following (non-exhaustive) key considerations:

- Marine and safety exclusion zones,
- Vessel draft / navigational requirements,
- Bathymetry,
- Wind, cyclone and wave data
- Geophysical information
- Site proximity to gas demand location and supply logistics

Assessment of strategic stock of LNG to be reserved for energy security will consider several critical factors including:

- Whether the Terminal is Base Load or Peak shaving,
- Criticality of industries for which LNG supply will be utilized for,
- Rules and regulations in the country for security of supply as advised by Client etc.
- Prevailing weather conditions and maximum potential downtime as a result of severe weather events
- Back-up / alternative fuel availability and optionality as advised by Client.

2.13 (Section 2: xii) Develop implementation plan:

The recommended implementation plan will greatly depend on the costs. Therefore the cost estimating activity described in 2.14 (see WBS) will be crucial to highlight the trade-offs between various options, screen out the uneconomical options and select a limited set of preferred/recommended actions. The implementation plan would include when and how to phase in the various aspects of the project, through amongst others, a high-level phasing in schedule, including target start dates, activity durations interrelationships and stakeholder engagement planning. Phases are likely to include design, construction, commissioning and operation of:

- LNG import facilities
- HFO conversion
- Power Plant
- Transport sector conversion to NG

2.14 (Section 2: xii) Develop cost estimate for implementation:

A Class 1 estimate is adopted (the Consultant's costing classification scheme). The confidence range will be < + 50 % and the contingency 15 – 25 %. The Confidence Range and Contingency will be estimated by judgment based upon the estimating assumptions. For this phase, the purpose of the cost estimate would be threefold: (1) To identify the potential value of the opportunity and its alignment with the overall business strategy, (2) To provide preliminary comparison of alternatives and (3) To access funding for pre-development, leading to the next project stage, "Feasibility". In terms of technical definition for a cost estimate at this phase, the scenarios must be developed and the locations of plant, and main processes and facility types must be specified.

The Consultant's estimating methods would be one or more of three tools:

- Cost v Capacity curves can be used, as can parametric estimates using historical cost data.
- Automated cost estimating software QUESTOR can also be used for onshore estimates.
- For more accurate estimates "Factorial" estimating can be used. Equipment costs and factors determining overall costs can be calculated using Historical Norms.

Specific to this project, taking into account the knowledge gained in previous activities, the cost estimate will in matrix format, highlight trade-offs between:

- Cost vs. benefit of converting HFO/kerosene power plants
- LNG importation infrastructure costs
- Sizes of CCGT power plant
- Site selection for the new CCGT power plant (Les Grandes Salines site vs. alternative possible sites)
- Fixed vs. operating costs over assets' lifetimes

This process will serve as a screening study to help select a limited set of recommended actions in terms of the above identified trade-offs.

3. (Section 2: xiii) ***Economic and financial modelling:***

The goal for this deliverable is to create ~~a~~ two financial models that integrates the economics of the new greenfield combined cycle gas turbine plant with the economics of the development, construction and operations of the LNG import infrastructure (LNG Import Terminal that will handle the unloading, storage, regasification and re-delivery of LNG), and the acquisition of LNG supplies. To accomplish the goal the Consultant will develop ~~an~~ excel-based economic cash flow models that will incorporate ~~and integrate~~the two major components:

- The Newbuild Project Generation Project Finance Model – This section of the model will focus on modeling the economics of developing, constructing and operating the greenfield CCGT power plant. Its output will be a tariff consisting of a capacity reservation charge and commodity charge. The capacity reservation charge will be designed to cover the fixed cost, including debt service, and return for the shareholder while the commodity charge should cover the cost of variable operating cost, which would primarily be the fuel cost. ~~(note: the structure of this tariff will have to be discussed with the Client during the Kick-off meeting) as well as t~~The projected cost of power will be based on the power plant tariff and cost of fuel for various scenarios resulting from the LNG Import Terminal and LNG Procurement

- LNG Import Terminal and LNG Procurement Project Finance Model – This section of the model will focus on modeling the economics of developing, constructing and operating a greenfield LNG Import Terminal. One of its outputs will be a tariff consisting of a capacity reservation charge and a throughput charge (note: the proposed structure of this tariff is typical for an LNG import terminal as it facilitates project financing~~), however, this approach will be discussed with the Client during the kick-off meeting)~~. The proposed tariff will be calculated for several LNG throughput scenarios that will reflect the analysis conducted in Tasks 2.6, 2.7 and 2.8 (see WBS) to address the various potential sources of LNG demand. This section of the model will then integrate various LNG pricing scenarios (assuming that LNG is priced on a DES basis – Delivered Ex-Ship basis – the island of Mauritius by the LNG supplier(s) as this is the most likely LNG purchase scenario applicable to a new market like the island of Mauritius in the context of current LNG market dynamics) and the tariff for the LNG Import Terminal to establish various "burner tip" cost of fuel scenarios to be used as inputs for the Newbuild Project Generation Project Finance Model section.

These two main components of the model will include the following modules:

- NewBuilt Power Generation Project Finance Model
    - Dashboard
    - Economic and global variables
    - Capital expenditure
    - Revenue and tariffs
    - Primary energy calculations
    - Operational and maintenance costs
    - Ongoing capital expenditure
    - Taxation, based on standard fiscal regime
    - Funding structure. A typical project finance structure will be assumed with a debt to equity ratio of 70%:30%
    - Hedging
    - Sensitivity calculator
    - Annual financial statements
    - Cash flows
- LNG Import Terminal and LNG Procurement Project Finance Model
    - Dashboard
    - Economic and global variables
    - LNG Fuel Requirements
    - LNG Pricing Scenarios
    - LNG Volumes Scenarios
    - Basket escalation functionality
    - Sales volumes
    - Technical data
    - Capital expenditure
    - Revenue and Tariffs

- Operational expenditure (fixed and variable)
- Taxation, based on standard fiscal regime
- Funding structure. A typical project finance structure will be assumed with a debt to equity ratio of 70%:30%
- Cash flows
- Free cash flow
- Financial and operational ratios (including NPV, IRR)
- Payback period
- Currency/volume calculation
- Capital loan overlay functionality
- Sensitivity calculator and scenario manager

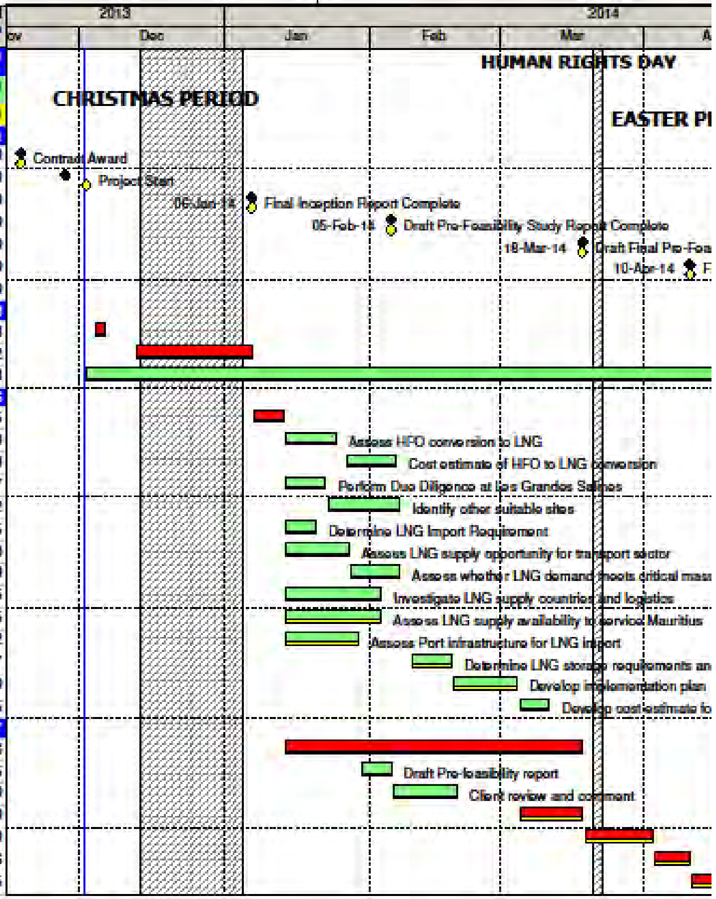
The following assumptions shall be used:

- The models will use standard fiscal assumptions for Mauritius.
- It is assumed the owner of both facilities (regas terminal and power plant) will be a State Owned Enterprise and funding assumptions will be based on expected terms available to a SOE in Mauritius.
- The model will be prepared in US$ [Client to confirm. Can also prepare in local currency if required]

Appendix E – Updated schedule

MAURITIUS LNG PRE-FEASIBILITY STUDY (All)

Activity ID	Activity Name	Start	Finish	Original Duration
MAURITIUS LNG PRE-FEASIBILITY STUDY (All)		18-Nov-13 A	06-May-14	101
WORLEYPARSONS		18-Nov-13 A	06-May-14	101
PRE-FEASIBILITY		18-Nov-13 A	06-May-14	101
MILESTONES		18-Nov-13 A	06-May-14	101
1.1	Contract Award	18-Nov-13 A		0
A5000	Project Start	28-Nov-13 A		0
A5010	Final Inception Report Complete		06-Jan-14	0
A5020	Draft Pre-Feasibility Study Report Complete		05-Feb-14	0
A5030	Draft Final Pre-Feasibility Study Report Complete		18-Mar-14	0
A5040	Final Pre-Feasibility Study Report Complete		10-Apr-14	0
A5050	Project Complete		06-May-14	0
PROJECT MANAGEMENT		02-Dec-13	29-Apr-14	88
1.2	Project Kick-off Meeting	04-Dec-13*	06-Dec-13	3
1.3	Final Inception Report	13-Dec-13	06-Jan-14	2
1.4	Project and Engineering Management	02-Dec-13	29-Apr-14	88
ENGINEERING		07-Jan-14	11-Mar-14	46
2.01	Develop Basis of Design	07-Jan-14	13-Jan-14	5
2.02	Assess HFO conversion to LNG	14-Jan-14	24-Jan-14	9
2.03	Cost estimate of HFO to LNG conversion	27-Jan-14	06-Feb-14	9
2.04	Perform Due Diligence at Les Grandes Salines	14-Jan-14	22-Jan-14	7
2.05	Identify other suitable sites	23-Jan-14	07-Feb-14	12
2.06	Determine LNG Import Requirement	14-Jan-14	20-Jan-14	5
2.07	Assess LNG supply opportunity for transport sector	14-Jan-14	27-Jan-14	10
2.08	Assess whether LNG demand meets critical mass requirements	28-Jan-14	07-Feb-14	9
2.09	Investigate LNG supply countries and logistics	14-Jan-14	03-Feb-14	15
2.10	Assess LNG supply availability to service Mauritius	14-Jan-14	03-Feb-14	15
2.11	Assess Port infrastructure for LNG import	14-Jan-14	29-Jan-14	12
2.12	Determine LNG storage requirements and options	10-Feb-14	18-Feb-14	7
2.13	Develop implementation plan	19-Feb-14	04-Mar-14	10
2.14	Develop cost estimate for implementation	05-Mar-14	11-Mar-14	5
PROJECT CONTROLS & COST MANAGEMENT		14-Jan-14	06-May-14	77
3	Economic and Financial modelling	14-Jan-14	18-Mar-14	46
4.1	Draft Pre-feasibility report	30-Jan-14	05-Feb-14	5
4.2	Client review and comment	06-Feb-14	19-Feb-14	10
4.3	Draft final Pre-feasibility report	05-Mar-14	18-Mar-14	10
4.4	Client review and comments	19-Mar-14	02-Apr-14	10
4.5	Final Pre-feasibility report	03-Apr-14	10-Apr-14	6
4.6	Contingency	11-Apr-14	06-May-14	15



Appendix 2 Basis of Design

WorleyParsons

resources & energy

Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius

Basis of Design (BoD)

282570

282570-MauritiusLNG-BoD-R2

21 March 2014

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SYNOPSIS

This document presents the preliminary Basis of Design (BoD) for the Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius. The BoD is used to identify key design inputs, criteria and key concerns associated with this project.

Disclaimer

PROJECT 282570 - BASIS OF DESIGN

REV	DESCRIPTION	ORIG	REVIEW	WORLEY-PARSONS APPROVAL	DATE	CLIENT APPROVAL	DATE
1	First draft issued for review	DBS, MB, CC	KM, GM, WJS	WJS	27 Jan 2014		
2	Updated with Client Comments	DBS, MB, CC	KM, GM, WJS	WJS	21 Mar 2014		

CONTENTS

LIST OF EXHIBITS

1. INTRODUCTION

1.1 Purpose of this document

This document presents the Basis of Design (BoD) for the Pre-Feasibility Study for Assessing the Potential of Using Liquefied Natural Gas (LNG) for Electricity Generation in Mauritius. The purpose of the BoD is to define the Customer's input and criteria to be used as part of the feasibility study. It is to be considered as an approved source of input data for the engineering team.

1.2 Background

CEB has 4 thermal power stations on the island of Mauritius: Fort George, Fort Victoria, St Louis, and Nicolay as shown below, along with IPP thermal power stations, CEB hydroelectric stations, and interconnecting transmission lines [1].

Exhibit 1-1: Island of Mauritius Electrical System

The plants at St. Louis, Fort George and Fort Victoria have diesel generators that run on HFO/distillate fuel while the Nicolay site has only gas turbine units running on Jet A1. Fort George operates as base load plant while St Louis and Fort Victoria operate as semi base load plants. Nicolay is dispatched for peaking and under emergency conditions. The details of existing power plants are provided in Section 6.

In order to reduce the dependency on the conventional energy resource (HFO) and promote cleaner generation, CEB wanted to explore the possibility of using LNG for power generation - both for the existing as well as for the new planned capacity additions (100MW LNG based power plant).

1.3 Project Objective

The objective of the pre-feasibility study is to assess the potential of using LNG primarily for electricity generation in Mauritius. The primary focus for the power generation is twofold:

1. To determine the feasibility of converting the existing CEB power plants to operate on LNG, and
2. to evaluate the feasibility of installing a new 100 MW power plant using LNG.

Relating aspects considered are the LNG supply and storage logistics and infrastructure requirements.

In order to maximize the LNG utilization in light of “critical mass” requirements, the study will also evaluate other utilization areas, such as transportation.

For a more detailed objective description, the reader is referred to the Inception Report.

2. SITE SPECIFIC DESIGN DATA

The data in this BoD is largely based on CEB supplied data supported by WP in-house data and publicly available information. It has been compiled for the purposes of feasibility assessment only and will be required to be further developed as the engineering progresses.

2.1 Ambient Data

Mauritius is typically tropical in the coastal regions with forests in the mountainous areas. Mauritius ranked second in an air quality index released by the World Health Organization in 2011. [2]

There are two seasons: a warm humid summer from November to April, with a mean temperature of 24.7°C and a relatively cool dry winter from June to September with a mean temperature of 20.4°C. The temperature difference between the seasons is only 4.3°C. The warmest months are January and February with average day maximum temperature reaching 29.2°C and the coolest months are July and August when average night minimum temperatures drops down to 16.4°C. [2]

The prevailing trade winds keep the East side of the island cooler and also tend to bring more rain. There can also be a marked difference in temperature and rainfall from one side of the island to the other. [2]

Ambient conditions by month for the recording station at Fort William near Port Louis are given in Exhibit 2-1.

Exhibit 2-1: Monthly Ambient Conditions for St Louis

Mean and Extreme Temperatures °C (1961 - 1980) Station: Fort William (St Louis)													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
Mean Maximum	29.4	31.2	31.0	30.1	28.6	26.9	26.0	25.9	27.2	28.3	29.9	30.6	28.8 ave
Absolute Maximum	34.6	**37.5**	35.6	34.3	32.8	32.0	30.9	30.5	30.6	34.5	33.0	35.4	37.5 max
Year of max *(75=1975)*	*75*	*75*	*61*	*69,79*	*61*	*77*	*73*	*77*	*79*	*76*	*often*	*76*	
Mean (Max. + Min.) / (2)	26.7	27.7	27.3	26.6	25.0	23.4	22.7	22.4	23.3	24.3	25.8	26.9	25.2 ave
Mean Minimum	23.9	24.1	23.7	23.1	21.4	19.9	19.4	18.9	19.3	20.3	21.7	23.3	21.6 ave
Absolute Minimum	15.5	18.5	18.0	17.0	12.5	12.9	**12.2**	12.5	12.7	14.1	15.0	15.8	12.2 min
Year of max *(62=1962)*	*62*	*62*	*66*	*71*	*66*	*66*	*66*	*70*	*66*	*66*	*66*	*66*	
Mean Daily Range	5.5	7.1	7.3	7.0	7.2	7.0	6.6	7.0	7.9	8.0	8.2	7.3	7.2 ave
Relative Humidity – Monthly Mean: St Louis													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
Relative Humidity (%)	65	72	74	78	68	69	71	62	62	61	68	71	68 ave

Reference: [3] for Fort William (St Louis)

The ambient conditions presented in Exhibit 2-2 are utilized for the design of the onshore facilities.

Exhibit 2-2: Ambient Conditions for use in design

Criteria	Units	Parameter
Annual average temperature *(Design value to be used for establishing equipment performance)*	(^{o}C)	25.2
Annual average Relative Humidity *(Design value to be used for establishing equipment performance)*	(%)	68
Average of Monthly Mean Max. temperature	(^{o}C)	28.8
Average of Monthly Mean Min. temperature	(^{o}C)	21.6
Extreme High Temperature (20 year period)	(^{o}C)	37.5
Extreme Low Temperature (20 year period)	(^{o}C)	12.2
Hottest Month [2]		February
Coldest Month [2]		August

Reference: [3] for St Louis.

2.1.1 Rainfall

The North and West of Mauritius are comparatively much drier than the other regions of the island. Generally the elevated land away from the coast is much wetter than the coastal strip. The monthly average rainfall for the recording station at Fort William near Port Louis is given in the exhibit below. The monthly average rainfall for the whole of Mauritius is also given for comparison.

Exhibit 2-3: Rainfall data per month

Month	Fort William (mm)	Whole of Mauritius (mm)
Jan	145	295
Feb	127	280
Mar	126	309
Apr	83	216
May	40	161
Jun	26	140
Jul	27	133
Aug	22	124

Sep	19	83
Oct	19	74
Nov	32	101
Dec	116	206
year	782	2122

Reference: [3]

The distribution of the total annual rainfall varies from place to place. However, it seems unlikely that there is great difference in the heaviest rainfall intensities over short periods in different localities. The following figures of maximum rainfall rates in Mauritius have been worked out from records over 85 years for the Meteorological Stations at Pamplemousses and Vacoas:

Exhibit 2-4: Rainfall data per period

Period	Rainfall (mm)
5 mins	15
15 mins	30
35 mins	61
1 hr	82
2 successive hrs	115
3 successive hrs	150
4 successive hrs	180
12 successive hrs	250
24 successive hrs	490

Reference: [3]

2.2 Ocean Data

2.2.1 Seawater Temperatures

The following design temperatures are utilized for potential seawater cooling.

Exhibit 2-5: Seawater Temperatures

Criteria	Temperature
Minimum Lagoon Seawater Temperature	22°C
Maximum Lagoon Seawater Temperature	27°C

Reference: [2]

Although no concurrent sea water data corresponding to design ambient condition, it is proposed to use the average sea water temperature of 24.5 °C to establish the equipment and plant performance where applicable.

2.2.2 Seawater Properties

Exhibit 2-6: Seawater Temperatures: Seawater Properties

Description	Unit	Properties
Density@15°C	kg/m³	1024
Kinematic Viscosity	m²s-1	10-6
Resistivity	Ohm.m	0.2089

2.2.3 Metocean Conditions

For the pre-feasibility report, preliminary information on metocean site specific conditions will be extracted from “Training Manual on Coastal Engineering. Climate Change Adaptation Programme in the Coastal Zone of Mauritius”. [20]

Multidirectional wave data (both statistical and spectral) and current flow information will have to be acquired for accurate option evaluation at further design stages. Time history of meteocean parameters should also be used for further assessment.

Preliminary bathymetric information is based on Admiralty Chart No 713 (Port Luois and Grand Riviere Noire Bay) [23].

2.2.4 Tidal levels

Preliminary information on tide levels (to Chart Datum) in the Port Louis Harbour are as follows [19]:

- M.H.W.S. = + 0.7 mCD
- M.H.W.N. = 0.5 mCD
- M.L.W.N. = 0.4 mCD
- M.L.W.S. = 0.2 mCD

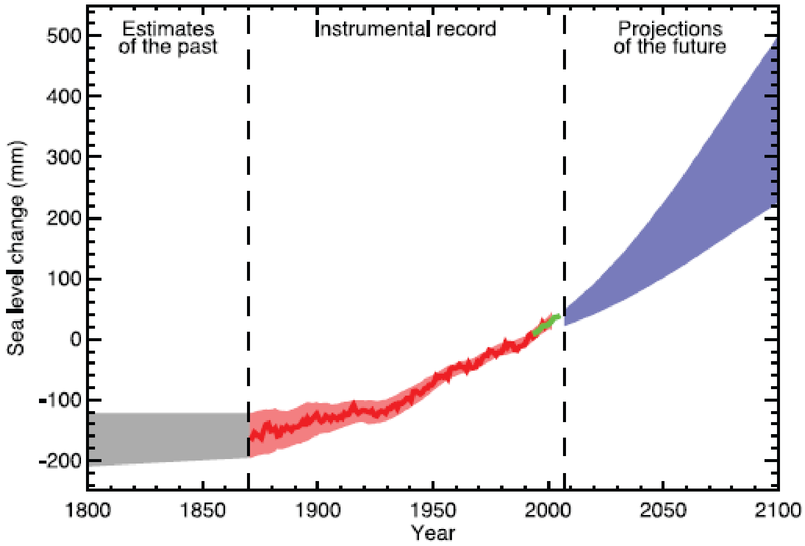
Accurate measurement of tidal levels will have to be carried out during following design stages.

2.2.5 Sea Level Rise

The Intergovernmental Panel on Climate Change (IPCC, 2007) estimate the average rate of sea level rise for the 20th century as 1.7 ± 0.5 mm/yr. The average estimated rate over the latter half of the 20th century and beginning of the 21st century (1961 to 2003) is 1.8 ± 0.5 mm/yr. As also stated in the IPCC report, recent analysis based on satellite altimetry observations indicate a sea level rise of 3.1 ± 0.7 mm/yr, over the period 1993 to 2003, which is almost twice as high as for the whole 20th century period.

Different projections of sea level rise have been made by the IPCC. They present estimates for a number of different scenarios that depend on population growth, GDP growth, energy use, land use changes, resource availability and pace and direction of technology. For example, for their A1B scenario (considered an "average" scenario) the predicted rate of sea level rise is between 2 and 5 mm/yr. Exhibit 2-7 depicts the time series of mean sea level in the past and projected for scenario A1B.

Exhibit 2-7: Time series of global mean sea level in the past and projected for the future (for scenario A1B). Extracted from IPCC (2007).



Other studies (UNEP, 2009) consider these estimations low and point to sea level rise values up to 2 m for the next 100 years. Recently, Mather (2009) presented a study where all available water level data along the South African coast was analysed. The author found that the sea level rise varied between 0.4 mm/yr at Mossel Bay to 2.7 mm/yr at Durban with the average sea level rise for the southern Cape coast estimated at 1.57 mm/yr.

It is recommended to use the upper end of the IPCC (2007) A1B estimate of 5 mm/yr (25 cm over a 50 year design life), at this stage of the design, but that due consideration be given to adopting a more conservative value during following design stages considering the criticality of the infrastructure under consideration.

2.2.6 Storm Surge

Periodic storm surges can result in higher water levels than expected from tidal predictions along the southern eastern coast of Mauritius. Appropriate storm surge levels will be determined based on analysis of water level records from the proposed site during further design stages [19].

2.2.7 Cyclonic Winds

Tropical cyclones occur in the South West Indian Ocean in the summer months of November to April, with the highest frequency in January and February. Mauritius has been visited by major cyclones on an average frequency of one in about 15 years. However, it should not be thought that there is a regular succession of cyclones occurring once every fifteen years. There is considerable irregularity in their occurrence [19].

The strongest gusts recorded instrumentally in Mauritius have been of 280 kilometres per hour (Feb 1975) and records of gusts of over 250 km per hour have been made in earlier cyclones. The values for 3 second gusts proposed by the Mauritius Meteorological Service in a paper dated May 1994 is as follows [19]:

- Return Period of 50 years: 240 km/hr
- Return Period of 100 years: 275 km/hr

The Mauritius Ports Authority and other authorities have recommended the use of a basic wind speed of 280km/hr for the design of buildings for recent projects.

A more thorough statistical analysis of wind speed supported by local measurements should be carried out at further design stages.

2.2.8 Tsunami Potential

Mauritius has been spared from the December 26, 2004 tsunami disaster and so far no significant tsunami affecting Mauritius has been recorded. Nevertheless, there is a possibility that Tsunamis generated from either the Sumatra or the Makran source may reach the coasts of Mauritius or Rodrigues [19]. Thus, additional studies on risk associated to tsunami hitting the Mauritian coast will have to be considered during further stages of design.

3. ENVIRONMENTAL

The limits for air emissions, effluent discharge, and noise as it relates to Power plants are presented below.

3.1 Air Emissions

The national standard for air emissions is documented in the 1998 Environmental Protection Regulations and is summarized in Exhibit 3-1.

Exhibit 3-1: Standards for Air Emissions

Parameter	Units	Permissible Limits	Notes
Smoke	Ringelmann no 2 or equivalent	2	All stationary fuel burning source (not to exceed >5 minutes in any 1 hr pd.)
Solid Particles	mg/m^3	200	Any fuel other than bagasse
Nitric Oxides (NOx)	mg/m^3	1000	As NO_2.
Sulfur Dioxides (SO_2)	mg/m^3	2000	As per proposed new regulations by MOESD
Carbon monoxide (CO)	mg/m^3	1000	

Reference: [4]

In addition to the stack limits, there is also ambient air limits expressed in the national regulation [4].

World Bank/IFC guidelines are also typically referenced in such projects. Per the IFC guidelines, when the host country regulations differ from the levels present in the IFC guidelines, projects are expected to achieve whichever is more stringent. Per the kick off meeting, the NOx and SO2 regulations are per the World Bank/IFC norms. The World Bank / IFC guidelines are presented in Exhibit 3-2 and Exhibit 3-3 for new reciprocating engines and new gas turbines respectively.

Note that it has been mentioned during the meeting with the MOESD that new air quality guidelines are currently being drafted. The publication date is not known at this stage and therefore, the Consultant will consider what is presented in this section.

Exhibit 3-2: Relevant World Bank / IFC Stack Emission Guidelines – New Reciprocating Engines

Parameter	Units	Permissible Limits	Notes
Natural Gas – Reciprocating Engine			
Particulate Matter (PM)	mg/Nm^3	NA	Not applicable
Nitric Oxides (NOx)	mg/Nm^3	200 (spark ignition) 400 (dual fuel)	Compression ignition may require different limits and are evaluated on a case by case basis.
Sulfur Dioxides (SO_2)	mg/Nm^3	NA	Not applicable
Liquid Fuels – Reciprocating Engine (Plant > 50 MWth to < 300 MWth)			
Particulate Matter (PM)	mg/Nm^3	50	
Nitric Oxides (NOx)	mg/Nm^3	1460 (CI, bore<400mm) 1850 (CI, bore≥400mm) 2000 (dual fuel)	CI is Compression ignition.
Sulfur Dioxides (SO_2)	mg/Nm^3	1170 or ≤3% S fuel	

Reference: [5]
Notes:

a. Limits presented are for non-degraded airsheds (NDA).
b. Guidelines are applicable to facilities operating more than 500 hours per year.
c. Evaluated with a dry gas, excess O_2 content of 15%.
d. Nm^3 is evaluated at 1 atm, and 0°C.
e. Emissions should be evaluated on a one hr average and be achieved 95% of annual operating hours.

Exhibit 3-3: Relevant World Bank / IFC Stack Emission Guidelines – New Gas Turbine

Parameter	Units	Permissible Limits	Notes
Natural Gas – Gas Turbine (Unit > 50 MWth HHV)			
Particulate Matter (PM)	mg/Nm^3	NA	Not applicable
Nitric Oxides (NOx)	mg/Nm^3	51 (25 ppmvd @15% O_2))	Including duct burner emissions, if applicable.
Sulfur Dioxides (SO_2)	mg/Nm^3	NA	Not applicable
Fuels other than Natural Gas – Gas Turbine (Unit > > 50 MWth HHV)			
Particulate Matter (PM)	mg/Nm^3	50	
Nitric Oxides (NOx)	mg/Nm^3	152 (74 ppmvd @15% O_2)	Including duct burner emissions, if applicable. Note f.
Sulfur Dioxides (SO_2)	mg/Nm^3	≤1% S fuel	

Reference: [6]
Notes:

a. Limits presented are for non-degraded airsheds’ (NDA).
b. Guidelines are applicable to facilities operating more than 500 hours per year.
c. Evaluated with a dry gas, excess O_2 content of 15%.
d. Nm^3 is evaluated at 1 atm, and 0°C.
e. Emissions should be evaluated on an one hr average and be achieved 95% of annual operating hours.

f. Technological differences (e.g., aero-derivatives) may require case by case consideration, but should not exceed 200 mg/Nm^3.
g. The World Bank Guidelines do not include limits for carbon monoxide (CO).

3.2 Effluent Discharge

The national standard for effluent discharge for Thermal Power Plants is documented in the 2003 Environmental Protection Regulations and is summarized in Exhibit 3-4.

Exhibit 3-4: Effluent Discharge Regulation Standards

Parameter	Units	Permissible Limits	Notes
Temperature	°C	40	
pH		5-9	
Total Suspended Solids (TSS)	mg/l	45 / 35	45 – Land / underground 35 – Surface Water
Copper	mg/l	0.5	
Iron	mg/l	2.0	
Total Chromium	mg/l	0.05	
Zinc	mg/l	2	
Oil & Grease	mg/l	10	

Reference: [7, 8]

The national standard for effluent discharge into the Ocean for Thermal Power Plants is documented in the 2003 Environmental Protection Regulations and is summarized in Exhibit 3-5.

Exhibit 3-5: Effluent Discharge into the Ocean Regulation Standards

Parameter	Units	Permissible Limits	Notes
Temperature	°C	40	
pH		5-9	
Floatables		6	
BioChemical Oxygen Demand (BOD)	mg/l	250	
Chemical Oxygen Demand (COD)	mg/l	750	
Total Suspended Solids (TSS)	mg/l	300	
Iron	mg/l	2.0	
Total Chromium	mg/l	0.05	
Zinc	mg/l	2	
Oil & Grease	mg/l	10	

Reference: [9]

Other parameters limited for discharge into the ocean include: cadmium, Chromium (VI), Cyanides, Lead, Nickel, Total Mercury, Arsenic, and total pesticides [9].

The Ocean discharge must be a distance of 300 meters off the barrier reef and at a depth of 30 meters or more if within a lagoon; or a distance of 500 meters from the high water mark and at a depth of 25 meters or more where there is no lagoon. No effluent should be discharged where it will be re-entrained as influent.

3.3 Noise

The standards for Noise are summarized below for Thermal Power Plants.

Exhibit 3-6: Power Station Noise Regulation Standards

Parameter	Time	Permissible Limits	Notes
In Residential Area	07.00 – 21.00	60 dB (A) Leq	
	21.00 – 07.00	55 dB (A) Leq	
In Any Other Areas	At any time	70 dB (A) Leq	

Reference: [10, 11]

4. FUEL

Fuels utilized by the CEB thermal power station include HFO for diesel engines, LFO for diesel engine startup and Jet A1 for gas turbines. The primary fuel cost for each plant and family of engines is presented in Exhibit 4-1.

Exhibit 4-1: Primary Fuel Cost and Utilization (Jan to Sep 2013)

Plant	Prime Mover	Primary Fuel	Generation (GWh)	% of GWh	Primary Fuel Cost (Rs/kWh)
Ft George	Diesel Engines	HFO 380 cSt	469.80	62.7%	4.15
Ft Victoria	MAN Diesel	HFO 180 cSt	6.86	0.9%	4.36
Ft Victoria	Wartsila Diesel	HFO 180 cSt	167.82	22.4%	4.27
St Louis	Pielstick Diesel	HFO 180 cSt	16.77	2.2%	4.52
St Louis	Wartsila Diesel	HFO 180 cSt	86.37	11.5%	4.26
Nicolay	Gas Turbines	Jet A1 kerosene	1.40	0.2%	14.79
Total	CEB Thermal		749.03	100.0%	4.22

4.1 Jet A1

Jet A1 fuel is used at Nicolay in the three gas turbines. Key fuel analysis parameters are provided below in Exhibit 4-2, with a full analysis provided in Exhibit 4-3.

Exhibit 4-2: Jet A1 Fuel for Nicolay Station – Key Parameters

Tested Parameter	Unit	Method	Limits	Results
Sulfur	% mass	ASTM D4294-03	Max 0.3	0.25
Density @ 15°C	kg/m³	ASTM D4052-96 (2002)	775 – 840	798.7
Viscosity @ minus 20°C	mm²/s	ASTM D 445-06	Max 8.0	3.739
Specific Energy, net	MJ/kg	ASTM D 3338-08	Min 42.8	43.2

Reference: [12]

Exhibit 4-3: Jet A1 Fuel for Nicolay Station – Full Analysis

SL. NO.	TESTS	TEST METHOD	LIMITS	TEST RESULTS
1	APPEARANCE:			
	Appearance	Visual	Clear,Bright and Visually free from Solid matter and un-dissolved water at normal ambient temperature	Clear, Bright and Visually free fromSolid matter andUndissolved waterat ambient temp
	Color	ASTM D 156-07a	Report	+22
	Particulate Contamination, mg/L	ASTM D 5452-08	Max 1.0	0.86
	Particulate, cumulative channel particle counts ISO Code as per Table 1of ISO 4406:1999	IP 565-08W		21/20/15
	>= 4 µm (c)		Report	7536.3
	>= 6 µm (c)		Report	7927.1
	>= 14 µm (c)		Report	181.2
	>= 21 µm (c)		Report	14.8
	>= 25 µm (c)		Report	4.2
	>= 30µm (c)		Report	0.6
2	COMPOSITION			
	Acidity total, mg KOH/gm	ASTM D 3242-08	Max 0.015	0.006
	Aromatics, % Volume	ASTM D 1319-08	Max 25.0	17.7
	Sulphur total, % Mass	ASTM D 4294-03	Max 0.30	0.25
	Sulphur mercaptan % Mass	ASTM D 3227-04a	Max 0.0030	0.0022
	OR Doctor Test	ASTM D 4952-02(2007)	Negative	NA
	Hydro processed components in batch, % vol		Report	Nil

Reference: [12]

Exhibit 4-3: Jet A1 Fuel for Nicolay Station – Full Analysis (Cont'd)

SL. NO.	TESTS	TEST METHOD	LIMITS	TEST RESULTS
	Severly Hydro Processed components in batch, % vol		Report	Nil
3	VOLATILITY			
	Distillation: Intial boiling point °C	ASTM D86-07b	Report	152
	Fuel recovered: 10% Volume at °C		Max 205	171
	50% Volume at °C		Report	195
	90% Volume at °C		Report	232
	End Point °C		Max 300	251
	Residue, % volume		Max 1.5	1.0
	Loss, % volume		Max 1.5	1.0
	Flash Point °C	IP 170-99	Min 38	42
	Density at 15 °C, kg/m3	ASTM D 4052-96(2002)	775 to 840	798.7
4	FLUIDITY			
	Freezing point °C	ASTM D 2386-06	Max Minus 47	-48
	Viscosity at minus 20°C (mm2/s)	ASTM D 445-06	Max 8.0	3.739
5	COMBUSTION			
	Smoke Point, mm OR	ASTM D 1322-97(2002)	Min 25.0	NA
	Specific Energy, net MJ/kg	ASTM D 3338-08	Min 42.8	43.2
	Smoke Point, mm	ASTM D 1322-97(2002)	Min 19.0	23
	and Naphthalene, % vol	ASTM D 1840-07	Max 3.0	1.3
6	CORROSION			
	Corrosion, Copper Strip, Class (2hrs at 100°C)	ASTM D 130-04	Max 1	No.1
7	STABILITY			
	Thermal stability (JFTOT) control Temperature 260°C Filter pressure differential mm Hg	ASTM D 3241-08a	Max 25.0	0
	Tube Deposit Rating (Visual)	ASTM D 3241-08a	Less than 3.0 No peacock or abnormal colour deposits	Zero No 'Peacock' or 'Abnormal' color deposits
8	CONTAMINANTS			
	Existent Gum, mg/100 ml	ASTM D 381-04	Max 7.0	2.0
	Micro Separometer (MSEP) rating Fuel with Static Dissipator Additive OR	ASTM D 3948-07	Min 70	95
	MSEP without SDA	ASTM D3948-07	Min 85	NA

Reference: [12]

An approximate price of the heavy fuel oil is 650 USD/ton [13].

4.2 HFO 180 cSt

The Heavy Fuel Oil (HFO) 180 cSt fuel is used at St Louis and Ft Victoria in the diesel engines. Key fuel analysis parameters are provided below in Exhibit 4-4.

Exhibit 4-4: LFO Fuel Specification (Primary Fuel for St Louis and Ft Victoria Stations)

Parameter	Unit	Max/Min	Spec	June	Sept
Ash	% W	Max	0.10	0.008	0.027
Gross Caloric Value	MJ/kg	Min	42	43.53	43.18
Net Caloric Value	MJ/kg	Min	40	41.06	40.79
Carbon Residue, Conradson	% W	Max	15	10.99	8.311
Flash Point, PMCC	°C	Min	60	72.5	-----
Pour Point	°C	Max	15	12	9.0
Density @ 15°C	kg/l	Min/Max	0.95/0.985	0.9368	0.951
Sodium	ppm	Max	50	7	26
Sulphur	% W	Min/Max	1.0/3.0	1.85	2.17
Vanadium	ppm	Max	100	22	61.9
Viscosity, Kinematic @ 50°C	cSt	Min/Max	160/180	161.5	160
Water	% V	Max	0.50	0.05	0.05
Aluminium + Silicon (*)	ppm	Max	30	<5	9.4
Calc. Carbon Aromatic Index		Max	850	807	822
Total Sediment Potential	% (m/m)	Max	0.10	<0.01	0.01
Total Sediment Existent	% (m/m)	Max	0.10	<0.01	0.01

Reference: [16]

The specific net energy for the LFO reported at Ft Victoria is 40.59 MJ/kg.

4.3 HFO 380 cSt

Heavy fuel oil is used at Ft George. Representative fuel analysis is provided below.

Exhibit 4-5: HFO 380 cSt Analysis

Tested Parameter	Unit	Result	RMG380 Standard	Method
Density @ 15°C	kg/m³	971.9	991	ISO 12185
Viscosity @ 50°C	mm²/s	334.4	380	ASTM D7042
Water	% V/V	0.1	0.5	ASTM D6304-C
Micro Carbon Residue	% m/m	16	18	ISO 10370
Sulfur	% m/m	3.46	4.5	ISO 8754
Total Sediment Potential	% m/m	0.01	0.1	ISO 10307-2
Ash	% m/m	0.02	0.15	LP 1001
Vanadium	mg/kg	64	300	IP 501
Sodium	mg/kg	8		IP 501
Aluminium	mg/kg	1		IP 501
Silicon	mg/kg	LT 1		IP 501
Iron	mg/kg	8		IP 501
Nickel	mg/kg	21		IP 501
Calcium	mg/kg	1		IP 501
Magnesium	mg/kg	LT 1		LP 1101
Zinc	mg/kg	LT 1		IP 501
Phosphorus	mg/kg	LT 1		IP 501
Potassium	mg/kg	LT 1		LP 1101
Pour Point	°C	LT 0	30	ISO 3016
Flash Point	°C	GT 70	60	ISO 2719-B
Asphaltene	% m/m	7.3		ASTM D3279

Reference: [14]

Exhibit 4-6: HFO 380 cSt Analysis- Calculated Parameters

Calculated Parameter	Units	Result	RMG380 Standard
Aluminium + Silicon	mg/kg	LT 2	80
Net Specific Energy	MJ/kg	40.32	
CCAI (Ignition Quality)	-	834	
Gross Specific Energy	MJ/kg	42.65	

Reference: [14]

Note: RMG 380 is a Marine Residual fuel oil standard.

4.4 LNG

LNG is supplied to terminals via LNG carriers, below is the range of LNG compositions that are likely to be supplied to the terminal. It shall be noted that the compositions listed below are the LNG compositions at the source. Due to BOG generation on the ships during transportation, the actual unloaded LNG composition at the terminal would be slightly different, typically reduction in lighter components from the LNG. For the purpose of the power plant evaluation, the analysis in Exhibit 4-7 will be considered as representative.

Lean and Rich LNG specifications are derived from the LNG Liquefaction Process and the need to adjust the HHV for specific countries demand; below are short definitions for Lean and Rich LNG:

a. If Liquefaction process removes all the LPG (propane and butane) and almost all Ethane - The LNG will be Lean.
b. If the Liquefaction process removes the Ethane, and LPG, but not that deeply; the LNG is Rich
c. Some quantity of Nitrogen is added at times in LNG to adjust the HHV to suit some world markets.

Exhibit 4-7: LNG Specification as per EN 1160

Composition (mol%)	Units	LNG (Lean)	LNG (Average)	LNG (Rich)
Nitrogen, (N_2)	mol %	0.5	1.79	0.36
Methane, (CH_4)	mol %	97.5	93.9	87.2
Ethane, (C_2H_6)	mol %	1.8	3.26	8.61
Propane, (C_3H_8)	mol %	0.2	0.69	2.74
i-Butane, (i-C_4H_{10})	mol %	-	0.12	0.42
n-Butane, (n-C_4H_{10})	mol %	-	0.15	0.65
Pentane, (C_5H_{12})	mol %	-	0.09	0.02
Molecular Weight	(kg/kmol)	16.41	17.07	18.52
Bubble Point Temperature @ 101,325 Pa	(°C)	-162.9	-166.5	-161.5
Density @ Bubble Point Temp. & 101,325 Pa	(kg/m^3)	432.7	449.5	464.9
Higher Heating Value (HHV)	(MJ/Sm^3)	38.22	38.76	42.59
Lower Heating Value (LHV)	(MJ/Sm^3)	34.43	34.95	38.51
Wobbe Index	(MJ/Sm^3)	50.73	50.43	53.19

Reference: [15]

4.4.1 Conversion Factors

Exhibit 4-8 provides an indicative conversion factor NG to LNG.

Exhibit 4-8: Conversion Factors (based on Average LNG Composition)

Convert	To	Multiply by
MMtpa (LNG)	tph (LNG)	114
MMtpa (LNG)	sm3/h (NG)	158,200
MMtpa (LNG)	mmscfd	130

5. LNG PLANT CONFIGURATIONS & DESIGN DATA:

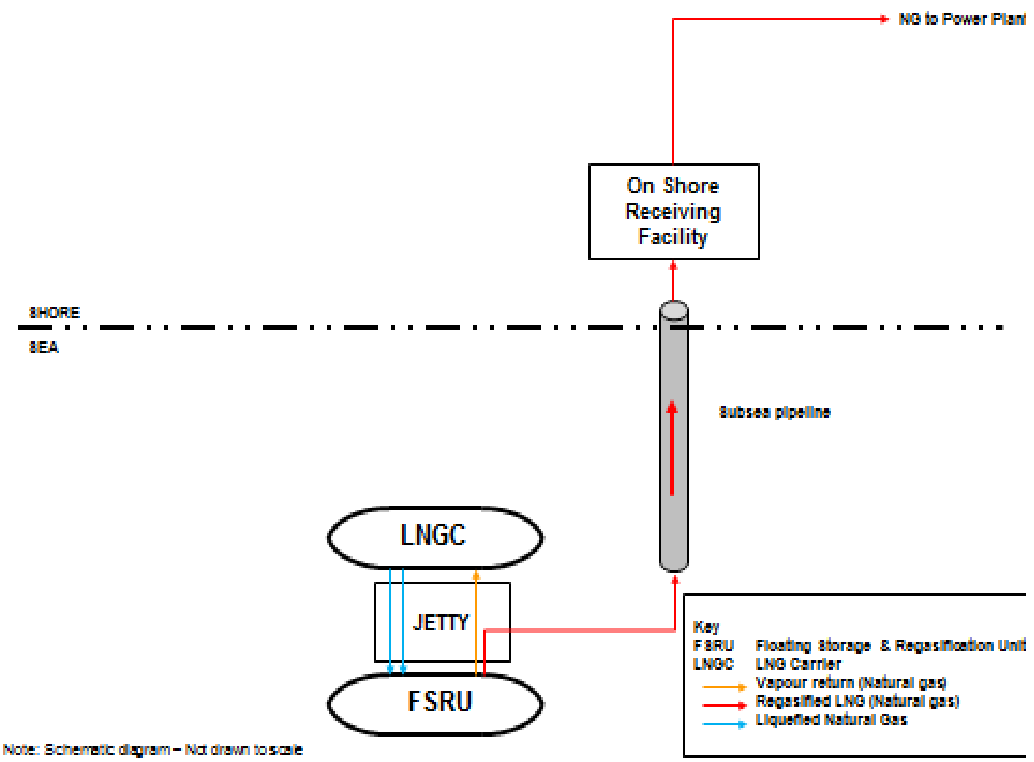
Following are the possible configurations to be studied:

5.1 Near Shore Configuration:

- LNG off-loading to a near shore Floating Storage and Regasification Unit (FSRU); FSRU berthed on one side of dual jetty, other side of Jetty for LNGC berthing for LNGC Unloading, subsea pipeline for HP gas to shore.
- Regasification of LNG on FSRU
- Send out sub-sea pipeline to on-shore
- On-shore Receiving Facility

Schematic Diagram for Near shore configuration is shown below.

Exhibit 5-1: Schematic Diagram for FSRU based Near shore LNG Terminal

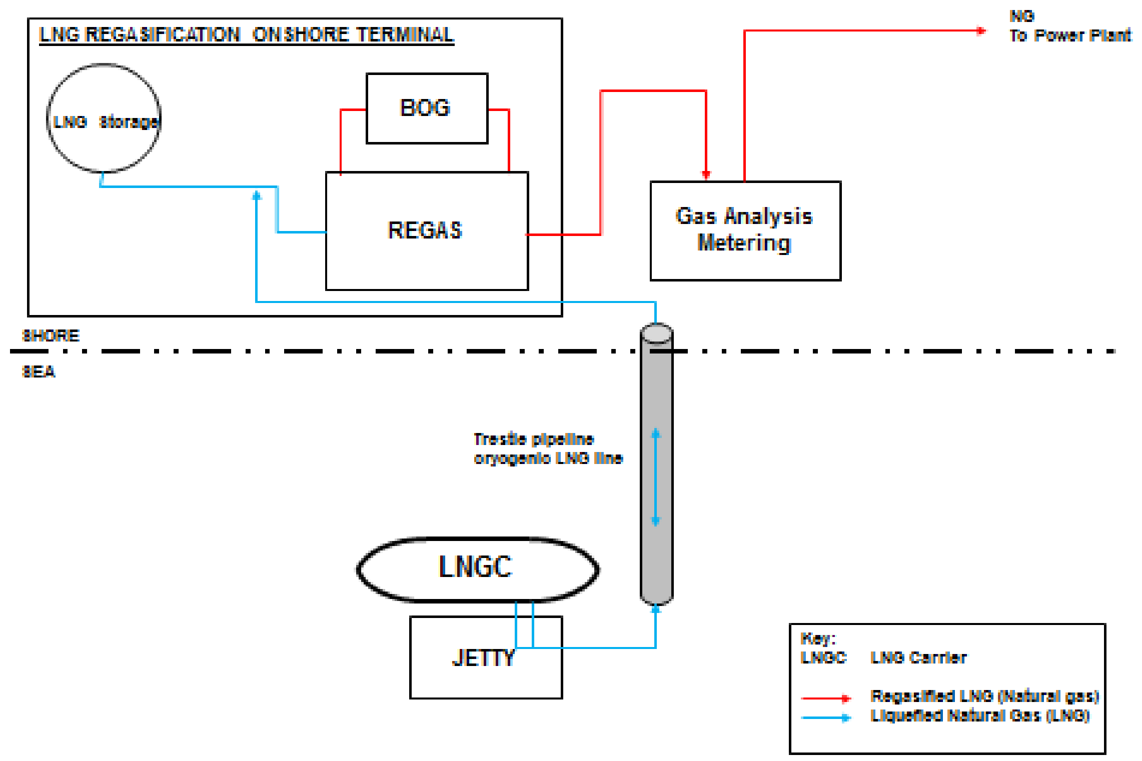


5.2 On Shore Option:

- LNG off-loading through a Jetty Berth, trestle for above water LNG lines to shore
- On-shore LNG storage
- Regasification of LNG
- Gas send out to Power Plant

Schematic diagram is shown below:

Exhibit 5-2: Schematic Diagram for Onshore LNG Terminal



Note: Schematic diagram – Not drawn to scale

5.3 Design Life

The facilities shall be designed for a life of 25 years. Where it is impractical for elements of the facilities to be specified with such a life, a review will be conducted together with Terminal Owner and the outcome shall be documented.

Following design life is to be considered for the different categories of equipment/ facilities:

- LNG Tanks 25 years
- Plant & Machinery 25 years
- Piping 25 years
- Jetty 25 years
- Instruments & Controls 15 years **(Note 1)**
- Buildings 25 years

Note 1: It is anticipated there will be continuous upgrading of the instrumentation and control systems over time.

All equipment with installed spares and piping that can be readily replaced during normal operation shall have a design life of 15 years. All other equipment and piping that cannot be readily maintained during normal operation; specifically the LNG tanks; loading lines, vapour return lines and export pipeline shall have a design life of 25 years.

5.4 Battery Limit Conditions

At the LNG Ship's manifold, the LNG unloaded will have the following typical minimum conditions.

- Pressure(abs): 120 m LNG
- Temperature: -160 deg c
- Ship LNG saturation pressure: 5 kPag max

Unloading Specifications

The terminal is designed to unload ships at the following rates at loading arm flanges

- NG Ship Size: 88,000 to 170,000 m^3
- Minimum unloading rate: 10,000 m^3/hr
- Maximum unloading rate: 12,000 m^3/hr
- Boil-off rate: 0.15% of full ship contents/day

5.5 Safety Distances/Zone

The definitions of Exclusion Zone and Safety Zone are as follows:

Exclusion Zone

Exclusion zone is a 'Keep out' or buffer distance as a part of Risk Management Strategy- prevention and mitigation. This type of approach has been used and is in use by the LNG industry, the Coast Guard, and public safety organizations to ensure the safety and transportation of LNG.

Safety Zone

Safety zone is for management approaches to reduce risks to public safety and property from LNG spills. The most significant impacts to public safety and property exist within approximately 500m of a spill, due to thermal hazards from fires.

Large unignited LNG vapour releases are unlikely. If they do not ignite, vapour clouds could spread over a distance greater than 1600m from spill.

Safety distances shall be considered in the berthing layout and navigation channel. These shall follow international standards. Preliminary safety distances are presented in Exhibit 5-3, below

Exhibit 5-3: Exclusion Zone

Exclusion Zone	Distance
Between Moored LNG carrier and Passing Vessel	250-300 m
Between Moored LNG Carriers	250-300 m
Air Draft	40-50m

5.6 Operational Safety Measures

- Jetty safety zones should be effectively policed while the ship and/or FSRU are alongside thus providing control over local vessels.
- Offshore safety zones should be effectively policed by a guard boat to limit the approach of small craft.
- Passing ships, close to the jetty, should have their speed controlled by the harbour VTS system.
- Communications procedures should be well established and tested.
- Contingency plans should be available in written form.
- Operating procedures should be available in written form.
- A Port Information/Regulation Booklet should be provided for passing operational advice to the ship.

6. EXISTING POWER PLANT DATA

The CEB has four thermal Power Stations on Mauritius, which are supplemented by hydroelectric Power Plants and IPP thermal plants. The prime mover, primary fuel, and service duty of each CEB thermal power plant is presented in Exhibit 6-1.

Exhibit 6-1: Existing CEB Thermal Plant Prime Mover, Fuel, and Service Duty

Plant	Prime Mover	Primary Fuel	Effective Cap. (MW)	Service	Note
Ft George	Diesel Engines	HFO 380 cSt (heated)	134	Base loaded	[18]
Ft Victoria	Diesel Engines	HFO 180 cSt	107	Daily Start Stop (semi base)	[18], start/stop: ~ 07:00 to 21:30] MAN should be stopped at night while Wartsila can be operated during the night.
St Louis	Diesel Engines	HFO 180 cSt	71.4	Daily Start Stop (semi base)	[18], start/stop: ~ 07:00 to 21:30]
Nicolay	Gas Turbines	Jet A1 kerosene	74	Daily Start Stop (Peaking)	[18], start/stop: ~ 07:00 to 21:30]

6.1 Fort George Power Station

Ft George Power Station is built in the industrial area of Ft George, and is located on the North side of the Harbor on reclaimed land. The station is built on a complex system of piles.

The key details of the generating units are presented in Exhibit 6-2. The primary fuel is heated 380 cSt HFO. Plant cooling is achieved by radiator coolers. Heating of HFO is through superheated water (600 kPa at 165˚C) produced by exhaust gas boilers.

Exhibit 6-2: Ft George Power Station Generating Units

Parameter	G1	G2	G3	G4	G5
Technology	ICE	ICE	ICE	ICE	ICE
Make	Sulzer	Sulzer	Mitsui MAN B&W	Hyundai MAN B&W	Hyundai MAN B&W
Model	9RTA76	9RTA76	9K80MC-S	9K80MC-S	9K80MC-S
Cycle	2 Stroke	2 Stroke	2 Stroke	2 Stroke	2 Stroke
Rated Capacity (MW)	24	24	30	30	30
Effective Capacity (MW)	22	22	30	30	30
Yr Commissioned	1992	1993	1997	1999	2000
Fuel, primary	380 cSt HFO	380 cSt HFO	380 cSt HFO	380 cSt HFO	380 cSt HFO
Heat Rate (MJ/kWh)	7.88	7.88	7.78	7.42	7.42
Fuel Pressure at Engine Inlet, (Bars)	13	13	8	8	8

Fuel Oil Temperature at Engine inlet, (°C)	130	130	130	130	130
Runtime since 2013-10-31, (hours)	145,277	144,665	122,297	101,769	98,604
Generation since commission (GWh)	2486.9	2415.1	2583.6	2190	2153.5

Reference: [1,14]

Site elevation is 3 meter above sea level.

6.2 Fort Victoria Power Station

The Ft Victoria Power Station generating unit information is presented in Exhibit 6-3.

Exhibit 6-3: Fort Victoria Power Station Generating Units

Parameter	G1	G2	G3	G4	G5	G6	G8	G9
Technology	ICE	ICE	ICE	ICE	ICE	ICE	ICE	ICE
Make	Wartsila	Wartsila	Wartsila	Wartsila	Wartsila	Wartsila	MAN	MAN
Model	16V46	16V46	16V46	16V46	16V46	16V46	8L58/64	8L58/64
Rated Capacity (MW)	15	15	15	15	15	15	9.8	9.8
Effective Capacity (MW)	15	15	15	15	15	15	8.5	8.5
Yr Commissioned	2010	2010	2012	2012	2012	2012	1989	1989
Fuel, primary	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO
Fuel, secondary	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Heat Rate (gm/kWh)	202.6	202.6	202.6	202.6	202.6	202.6	215	215
Heat Rate (MJ/kWh)	8.224	8.224	8.224	8.224	8.224	8.224	8.727	8.727

Reference: [1,16]

The Fort Victoria Wartsila units are dual fuel capable. MAN units normally operate from 07:00 to 21:00. Heating of HFO is through superheated water/saturated steam (600 kPa at 165˚C) produced by exhaust gas boilers.

Heat and mass balances were performed at 36C /73% RH, and 1012 mbar. Plant cooling is achieved via a sea water (MAN) and radiator cooling system (Wartsila). [16]

The Wartsila units are dispatched at 12 MW, but no less than 10 MW for efficiency reasons. The Wartsila units can be operated at night, while the MAN units are typically started in the morning (0600) and turned off at night. [18]

There is no significant limitation in site accessibility. The Ft Victoria Power Station is accessible by heavy truck form the harbor along the motorway via Cassis Road to the site. Weights of up to 250 to 300 tons have been proven. The main obstacles are 8 bridges which require propping, and overhead lines which require lifting. Deliveries of up to 4 m wide by 25 m long have been proven.

6.3 Saint Louis Power Station

The St Louis Power Station generating unit information is presented in Exhibit 6-4.

Exhibit 6-4: Saint Louis Power Station Generating Units

Parameter	G1	G2	G3	G4	G5	G7	G8	G9
Technology	ICE	ICE	ICE	ICE	ICE	ICE	ICE	ICE
Make	Pielstick	Pielstick	Pielstick	Pielstick	Pielstick	Wartsila	Wartsila	Wartsila
Model	18PC3V	18PC3V	18PC3V	18PC3V	18PC3V	16V46	16V46	16V46
Rated Capacity (MW)	11.9	11.9	11.9	11.9	11.9	13.8	13.8	13.8
Effective Cap (MW)	6	6	6	6	6	13.8	13.8	13.8
Yr Commissioned	1978	1978	1979	1979	1981	2006	2006	2006
Fuel, primary	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO	180 cSt HFO
Fuel, secondary	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Heat Rate (MJ/kWh)	9.34	9.34	9.34	9.34	9.34	8.2	8.2	8.2
Cooling Scheme	Cooling tower	Cooling tower	Cooling tower	Cooling tower	Cooling tower	Air cooled radiators	Air cooled radiators	Air cooled radiators

Reference: [1,17]

The G6 Pielstick unit was retired in July 2012 [17]. The old Pielstick Power House (units G5 and G6) will be demolished. A new power house shall be constructed to house 4 new 15 MW dual fuel units (LNG and HFO 180 Cst) medium speed diesel engines [18].

The site elevation is 37.123 meters.

There is a 250 ton weight restriction at the entrance of the St Louis Power Station. [17]

6.4 Nicolay Power Station

The Nicolay Power Station generating unit information is presented in Exhibit 6-5. Heat and mass balances ambient conditions range from a min of 17°C to a max of 35°C with a design value of 30°C. The relative humidity range between 49% and 99%. The plant elevation is 70 ft, (1016 mbar).

Exhibit 6-5: Nicolay Power Station Generating Units

Parameter	G1	G2	G3
Technology	GT	GT	GT
Make	GE (Alsthom)	GE (GEC Alsthom)	GE (European GT)
Model	Frame 5 (MS-5001-P)	Frame 5 (MS-5001-PA)	Frame 6B (MS-6541-B)
Cycle	Open	Open	Open
Rated Capacity (MW)	21.8	22.7	33.9
Effective Capacity (MW)	21	21	32
Yr Commissioned	1988	1991	1995
Fuel	Jet A1	Jet A1	Jet A1
Heat Rate, Design (kJ/kWh)	13,020	12,847	11,500
Effective Efficiency, 2013 (%)	25.70%	26.20%	28.60%

Reference: [1,12]

There is no significant limitation in site accessibility. The Nicolay Power Station is located about 2 km from the port with no significant size or weight limitation with respect to spare parts / equipment. Containers up to 40 feet can be transported to the power plant.

7. NEW POWER PLANT DATA

Based on the discussions at the Kick Off meeting with CEB, it was agreed that the following technologies will be considered for the 100 MW generation capacity addition to capture the impact of relatively low capacity factor.

- One with Aero-derivative Gas Turbines based CC Project
- One with Industrial Gas Turbines based CC project
- One with multiple reciprocating engines (could have distillate support during LNG firing, if needed)

The prime mover capacity shall not exceed 50 MW in any of the above technologies.

Addition criteria for the New Plant are presented below.

- The maximum size of a prime mover shall not exceed 50 MWe. [21]
- Any new plant site would need to be 500 m from the coastline, and 1 km from residential area. The 1 km exclusion zone is not a rigid rule, and a smaller exclusion zone can be applied for if required. [13]

8. NEW SITE DATA

This section presents information on the three potential new sites proposed by CEB for investigation during the site visit. Out of the three sites, only the Les Grandes Salines site is considered viable for the new power plant.

8.1 Les Grandes Salines Site

An aerial photograph of the Les Grandes candidate site is presented in Exhibit 8-1.

Exhibit 8-1: Les Grandes Saline Site (Bain des Dames)

As documented within the inception report:

1. CEB is planning to put 6 tanks each of 6,500 m^3 at this site.
2. The new power plant must accommodate the new six tanks. The tanks would support the needs of additional 4 x 15 MW HFO power plant at Port Louis and also support the needs for the Rodrigues Island.

3. A CAD version of the site drawing showing the latest tank layout has been provided to the Consultant and will be used as the starting point for determining space requirements and high level equipment placement.

4. The site looks potentially good for the power plant, also considering the proximity of the LNG tanker jetty.

8.2 JinFei - Baie de Tombeau – West Coast Site

Based on the physical site visits and discussions with the Ministry of Environment and Ministry of Housing and Land, the Baie de Tombeau (Jin Fei) site is deemed unsuitable (from first inspection) for a new power plant for the following reasons.

1. The site is surrounded by residential areas.
2. The site is located relatively far from the shore line and this would create some difficulties in LNG to Power Plant integration.
3. Right of way would be an issue.
4. The site is a s pecial purpose zone. The property is leased to the Chinese government. The Chinese government can sub-lease it to others for similar usage as in the original lease but it probably can't be converted into an Industrial zone for Power Plant.
5. Since the site is surrounded by residential zone, it also requires special attention on what can be put at the site

Considering the above, the alternate site is not considered to be a good location for the new power plant.

8.3 Old Port Site - Bois des Amourettes- East Coast Site

The Bois des Amourettes alternate site had the following characteristics:

1. The existing jetty is very small, the water depth seems very shallow (based on the colour of water) and would require a significant rework for any new LNG import facility.
2. Based on discussions with the Ministry of Environment, the marine location has corals and Ministry of Fishery has special regulations on not damaging/ disturbing the coral reef.
3. The existing old oil tanks (from Second World War era) are located on the hill side. The tank walls are collapsed and the site will require significant earthwork and demolition for any new power plant.
4. There are residential areas close by. The area is very scenic with a lot of good vegetation and flowers. A new power plant in the area will require removing / relocation of the flora and would disturb the current environment.
5. There are hardly any industries or any major load centre and there does not seem to be any HV transmission line close by.

Considering all the above, the alternate site is not considered to be a good location for the new power plant.

9. MARINE INFRASTRUCTURE

9.1 Approach Channel, Turning Basin and Berthing Area

PIANC (Permanent International Association of Navigation Congresses) standards shall be used in the desktop study to determine initial channel and turning basin depth, width and alignment. Navigation studies will be required to determine more accurate approach channel and turning basin dimensions for the range of vessel types and also to determine limiting conditions of waves, current and tides. Under-keel clearances shall be established according to vessel size, environmental and sea-bed characteristics. The channel depth shall be designed to accommodate the fully laden draft of the largest vessel subject to wave action during all tides. The channel depth shall also allow for sedimentation build up and survey accuracy allowance. Typical dimensions for turning basin, navigation channel width and depth are presented in Exhibit 9-1.

Exhibit 9-1: Typical Dimensions for Approach Channel and Turning Basin.

Dimensions	
Underkeel clearance	10% to 20% of vessel draft
Turning basin	2 to 3 x LOA
Channel Width	5 to 8 x B
Berth pocket	1.25 x B by 1.25 x LOA

9.1.1 Navigational Aids

Navigational aids are required to indicate the approach channel, turning basin and berths. It will be necessary to identify resulting navigation hazards such as wrecks, submerged obstructions and ordnance. Navigational aids shall be designed according to the International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA) and supported by navigation studies.

9.1.2 Dredging

Dredging of the approach channel, mooring area and turning basin may become necessary. As the site still needs to be confirmed and it is expected that limited bathymetric information would be available, it is not possible to estimate required dredging volumes at this stage. Such an estimate should be carried out once sufficient information on site bathymetry, vessel characteristics, navigation requirements and terminal facilities are available.

Side slopes will depend on the findings of the geotechnical investigation but is anticipated to be initially set at 1:2 in solid rock material and 1:6 for sand/gravel. Slopes will be designed to remain stable and to mitigate excessive siltation of the area and subsequent maintenance dredging.

Selection of suitable dredging equipment will require information regarding the environmental conditions in the area, in particular geotechnical, waves, tides and currents.

It will also be necessary to identify a dump site which meets the national environmental standards as well as those of the Client. As a minimum, it is expected that a bathymetric survey and environmental assessment to meet statutory requirements will be necessary. Depending on the demands of the statutory authorities it may also be necessary to undertake dispersion modelling of dumped material.

9.1.3 Breakwaters

In the event that the selected site is located in an area with excessive wave attack and/or strong currents protective breakwater structures will be required. The breakwater configuration shall be derived through a combination of desk studies, numerical and physical models. Breakwater design shall be carried out according to the applicable design codes. Aspects to be considered in the design are the following:

- Slip circle stability
- Armour layer stability
- Side slope
- Under layers
- Wave overtopping
- Toe protection
- Constructability

9.1.4 Scour Protection

Scour protection will likely be necessary to protect the seabed from erosion due to the vessels propellers and environmental conditions. The final scour protection design will be established once the design vessel and design environmental conditions have been finalised.

9.1.5 Material Properties (rock for breakwater and scour protection)

The following rock properties presented below will be used for the design of breakwaters and scour protection, as well as for quality control during construction.

Exhibit 9-2: Rock Properties

Parameter	Value
Density (kg/m^3)	> 2650
Water Absorption (%)	<2%
Point Load Strength (MPa)	>4.0
Shape (length to thickness ratio, l/d)	<3.0

9.1.6 Regulatory Requirements

The design of the marine infrastructure may refer to the following list of codes and standards as appropriate:

- Local codes and regulations
- International Convention of the Safety of Life at Sea, SOLAS 1974 with amendments, including the IMO Gas Code (IGC Code);

- International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) 1993 Edition, International Maritime Organisation;
- International Regulations for Preventing Collisions at Sea (COLREG), Amended to 29th November 2003;
- International Convention for the Prevention of Pollution from ships 1973, MARPOL 73/78, with amendments;
- International Safety Management Code (ISM Code) [IMO SOLAS Chapter 9];
- International Convention on Load Lines, 1966, with amendments;
- DnV OSS 103, Rules for Classification of LNG/LPG Floating Production and Storage Units or Installations;
- Society of International Gas Tankers and Terminal Operators (SIGTTO);
- Oil Companies International Marine Forum (OCIMF) guidelines;
- 1993 Code (IMO ref 104E) covers vessels built from 1 October 1994;
- 1983 Code (IMO ref 782E) covers vessels built from 1 July 1986 to 30 September 1994.
- PIANC guidelines: ”Approach Channels, A Guide for Design” – 1997
- PIANC guidelines: “ Guidelines for the design of fender systems: 2002”
- British Standard BS 6349-Part 2: “Design of quay walls, jetties and dolphins” 2000
- British Standard BS 6349- Part 4 “ Code for practice for design of fendering and mooring systems”,1994.
- British Standard BS 8110 : Part 1 “ Structural Use of Concrete - Code of Practice for Design and Construction”, 1997
- DNV-RP-B401 “Recommended Practice for Cathodic Protection Design”, 2005
- API RP 2A-LRFD ”Recommended Practice for Planning, Designing and Constructing Fixed Offshore platforms - Load and Resistance factor design, American Petroleum institute (API)” 1993
- API RP 2A-WSD “Recommended Practice for Planning, Designing and Constructing Fixed Offshore platforms – Working Stress design, American Petroleum institute (API)” 2007
- NFPA – (National Fire Protection Association) guideline for LNG

In the event of an inconsistency, conflict or discrepancy between any of the Standards, Specifications and Regulatory, the most stringent and safest requirement applicable to the project will prevail to the extent of the inconsistency, conflict or discrepancy. The specific codes and standards will be subject to further review and possible amendment as the project progresses.

10. REFERENCES

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13. Meeting Record, "Wrap up meeting", December 6, 2013.
14. Fort George Power Station, word document received per DIR request.
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20. Training Manual on Coastal Engineering. Climate Change Adaptation Programme in the Coastal Zone of Mauritius. Ministry of Environment and Sustainable Development.. WorelyParsons RSA, 2013.
21. Kick Off Meeting Notes for December 4 to 6, 2013, including the Annotated Appendix F.
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23. Admiralty Chart No 713

Appendix 3 LNG Import Terminal Model AFS

Project & Sponsor:	Mauritius LNG Terminal | CEB	Equity IRRs	Scenario	FSRU Base case 5
Purpose & Status:	Viability Assesment | Draft	Nom: 20%	Valid?	-
Sheet:	AFS	Real: 15.87%	Breach?	1

Financial Statements (USD '000)

			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	01-Sep-16	01-Jan-16	01-Jan-16	01-Jan-17	01-Jan-18	01-Jan-19	01-Jan-20	01-Jan-21	01-Jan-22	01-Jan-23	01-Jan-24	01-Jan-25	01-Jan-26	01-Jan-27	01-Jan-28	01-Jan-29
			31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29
Cashflows			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Revenue																
Processing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity	3,672,400	3,672,400	-	-	47,143	95,935	99,293	102,768	106,365	110,088	113,941	117,929	122,057	126,329	130,750	135,326
Interest Income	1,458	1,458	-	-	28	84	115	151	175	130	76	56	56	56	57	-
Total	3,673,858	3,673,858	-	-	47,171	96,020	99,408	102,919	106,541	110,218	114,017	117,985	122,113	126,385	130,807	135,326
OpEx																
Fixed	(2,010,128)	(2,010,128)	-	-	(34,797)	(69,399)	(70,310)	(70,865)	(71,636)	(72,437)	(73,465)	(74,123)	(75,010)	(75,930)	(77,091)	(77,866)
Variable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Site Rental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agency Fees (Ops.)	(628)	(628)	-	-	(27)	(54)	(56)	(58)	(60)	(62)	(65)	(67)	(69)	(72)	(36)	-
Total	(2,010,755)	(2,010,755)	-	-	(34,824)	(69,453)	(70,367)	(70,923)	(71,696)	(72,500)	(73,530)	(74,190)	(75,080)	(76,001)	(77,127)	(77,866)
Working Capital Adjustments																
Debtors	-	-	-	-	(7,686)	(269)	(278)	(288)	(298)	(309)	(320)	(331)	(342)	(354)	(367)	(379)
Creditors	-	-	-	-	5,678	59	60	63	65	67	69	72	74	77	74	82
VAT	-	-	-	-	308	32	33	35	36	37	38	40	41	43	45	46
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Adjustment	-	-	-	-	(1,701)	(177)	(185)	(191)	(198)	(205)	(212)	(219)	(227)	(235)	(248)	(252)
Operating Cashflows	1,663,103	1,663,103	-	-	10,647	26,389	28,856	31,805	34,647	37,514	40,276	43,577	46,806	50,149	53,431	57,208
CapEx																
Construction Costs	(179,713)	(179,713)	(42,587)	(114,210)	(22,917)	-	-	-	-	-	-	-	-	-	-	-
Land Purchase /Lease	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility IDC	(6,791)	(6,791)	-	(2,381)	(4,410)	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Up Front Fees	(1,784)	(1,784)	(1,784)	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Commitment Fees (incl. Agency	(946)	(946)	(261)	(589)	(95)	-	-	-	-	-	-	-	-	-	-	-
Spare 2 IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Up Front Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Commitment Fees (incl. Agency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DoE Development Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Paid	(27,099)	(27,099)	(6,427)	(17,220)	(3,452)	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve Initial Funding	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c Initial Funding	(8,709)	(8,709)	-	-	(8,709)	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(225,042)	(225,042)	(51,059)	(134,400)	(39,583)	-	-	-	-	-	-	-	-	-	-	-
Funding																
Senior Debt Facility	118,930	118,930	-	86,607	32,324	-	-	-	-	-	-	-	-	-	-	-
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity	79,287	79,287	47,771	31,516	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Refund	27,099	27,099	3,288	16,277	7,534	-	-	-	-	-	-	-	-	-	-	-
Total	225,316	225,316	51,059	134,400	39,857	-	-	-	-	-	-	-	-	-	-	-
Cashflow After Funding	1,663,377	1,663,377	-	-	10,921	26,389	28,856	31,805	34,647	37,514	40,276	43,577	46,806	50,149	53,431	57,208
Tax	(218,409)	(218,409)	-	-	-	-	-	-	-	-	(5,105)	(5,777)	(6,425)	(7,102)	(7,785)	(8,401)
Net FX Swaps Gain/(Loss)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Maintenance Reserve	1,444,968	1,444,968	-	-	10,921	26,389	28,856	31,805	34,647	37,514	35,171	37,800	40,382	43,047	45,646	48,807
Major Maintenance Reserve																
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Maintenance Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve																
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CFADS	1,444,968	1,444,968	-	-	10,921	26,389	28,856	31,805	34,647	37,514	35,171	37,800	40,382	43,047	45,646	48,807
Senior Debt Service																
Interest	(54,818)	(54,818)	-	-	(4,693)	(8,828)	(8,170)	(7,411)	(6,617)	(5,759)	(4,846)	(3,832)	(2,751)	(1,584)	(326)	-
Principal	(118,930)	(118,930)	-	-	(4,016)	(8,540)	(9,213)	(9,958)	(10,753)	(11,611)	(12,533)	(13,539)	(14,620)	(15,787)	(8,360)	-
Total	(173,749)	(173,749)	-	-	(8,709)	(17,368)	(17,384)	(17,370)	(17,370)	(17,370)	(17,379)	(17,371)	(17,371)	(17,371)	(8,686)	-
Cashflow Available for DSRA/c	1,271,219	1,271,219	-	-	2,211	9,021	11,473	14,435	17,277	20,145	17,792	20,428	23,011	25,676	36,960	48,807
Debt Service Reserve Account																
Addition	(230)	(230)	-	-	-	(46)	(28)	(38)	(33)	(28)	(16)	(19)	(13)	(8)	-	-
Release for Shortfall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release for Excess Target	8,939	8,939	-	-	-	49	30	40	35	31	17	21	16	11	8,690	-
Total	8,709	8,709	-	-	-	2	1	2	2	2	2	3	3	3	8,690	-
Cashflow Available for Mezz Debt	1,279,929	1,279,929	-	-	2,211	9,023	11,474	14,438	17,279	20,147	17,794	20,431	23,013	25,678	45,650	48,807
Mezzanine Debt																
Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Senior Cashsweep	1,279,929	1,279,929	-	-	2,211	9,023	11,474	14,438	17,279	20,147	17,794	20,431	23,013	25,678	45,650	48,807
Senior Cashsweep																
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for S/h Loan	1,279,929	1,279,929	-	-	2,211	9,023	11,474	14,438	17,279	20,147	17,794	20,431	23,013	25,678	45,650	48,807
S/h Loan																
Interest	(3)	(3)	-	-	(0)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
Principal	(59,466)	(59,466)	-	-	-	(3,304)	(6,607)	(6,607)	(6,607)	(6,607)	(6,607)	(6,607)	(6,608)	(6,608)	(3,304)	(0)
Total	(59,470)	(59,470)	-	-	(0)	(3,304)	(6,608)	(6,608)	(6,608)	(6,608)	(6,608)	(6,608)	(6,608)	(6,608)	(3,304)	-
Cashflow Available for Equity	1,220,459	1,220,459	-	-	2,211	5,719	4,866	7,830	10,672	13,539	11,186	13,823	16,406	19,071	42,346	48,807
Equity Plug During Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dividends (before Dividend Tax	(1,220,459)	(1,220,459)	-	-	-	-	-	(563)	(17,524)	(20,696)	(17,240)	(13,823)	(16,406)	(19,071)	(42,346)	(48,807)
Net Cashflow	(0)	(0)	-	-	2,211	5,719	4,866	7,267	(6,852)	(7,157)	(6,054)	-	-	-	-	-
Cash Balance B/f			-	-	64	8,610	17,869	29,130	36,724	22,866	6,054	-	-	-	-	-
Cash Balance C/f			-	-	2,275	14,329	22,735	36,396	29,872	15,709	-	-	-	-	-	-
Cash Balance < 0		0 Breach(es)														

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	01-Jan-30	01-Jan-31	01-Jan-32	01-Jan-33	01-Jan-34	01-Jan-35	01-Jan-36	01-Jan-37	01-Jan-38	01-Jan-39	01-Jan-40	01-Jan-41	01-Jan-42	01-Jan-43
	31-Dec-30	31-Dec-31	31-Dec-32	31-Dec-33	31-Dec-34	31-Dec-35	31-Dec-36	31-Dec-37	31-Dec-38	31-Dec-39	31-Dec-40	31-Dec-41	31-Dec-42	31-Dec-43
Cashflows	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Revenue														
Processing	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity	140,063	144,965	150,039	155,290	160,725	166,351	172,173	178,199	184,436	190,891	197,572	204,487	211,644	107,642
Interest Income	-	-	-	-	-	-	2	34	76	84	82	79	77	37
Total	140,063	144,965	150,039	155,290	160,725	166,351	172,175	178,233	184,511	190,975	197,654	204,567	211,721	107,679
OpEx														
Fixed	(78,888)	(79,944)	(81,258)	(82,166)	(83,335)	(84,545)	(86,030)	(87,092)	(88,434)	(89,822)	(91,507)	(92,747)	(94,288)	(47,143)
Variable	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Site Rental	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agency Fees (Ops.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(78,888)	(79,944)	(81,258)	(82,166)	(83,335)	(84,545)	(86,030)	(87,092)	(88,434)	(89,822)	(91,507)	(92,747)	(94,288)	(47,143)
Working Capital Adjustments														
Debtors	(393)	(407)	(421)	(435)	(451)	(466)	(483)	(500)	(517)	(535)	(554)	(573)	(593)	17,550
Creditors	85	88	91	94	98	101	105	108	112	116	120	124	129	(7,813)
VAT	47	49	50	52	54	56	58	60	62	64	67	69	71	(1,493)
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Adjustment	(260)	(269)	(279)	(289)	(299)	(309)	(320)	(331)	(343)	(355)	(367)	(380)	(393)	8,244
Operating Cashflows	60,915	64,751	68,502	72,835	77,091	81,497	85,825	90,810	95,735	100,798	105,780	111,440	117,040	68,781
CapEx														
Construction Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Land Purchase /Lease	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Up Front Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Commitment Fees (incl. Agency	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Up Front Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Commitment Fees (incl. Agency	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DoE Development Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Paid	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve Initial Funding	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c Initial Funding	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Funding														
Senior Debt Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Refund	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow After Funding	60,915	64,751	68,502	72,835	77,091	81,497	85,825	90,810	95,735	100,798	105,780	111,440	117,040	68,781
Tax	(8,959)	(9,536)	(10,100)	(10,751)	(11,391)	(12,053)	(12,704)	(13,454)	(14,303)	(15,173)	(15,922)	(16,773)	(17,615)	(9,080)
Net FX Swaps Gain/(Loss)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Maintenance Reserve	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Major Maintenance Reserve														
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Maintenance Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve														
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CFADS	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Senior Debt Service														
Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for DSRA/c	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Debt Service Reserve Account														
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release for Shortfall	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release for Excess Target	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Mezz Debt	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Mezzanine Debt														
Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Senior Cashsweep	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Senior Cashsweep														
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for S/h Loan	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
S/h Loan														
Interest	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Equity	51,956	55,216	58,402	62,084	65,700	69,443	73,120	77,356	81,432	85,625	89,858	94,667	99,425	59,700
Equity Plug During Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dividends (before Dividend Tax	(51,956)	(55,216)	(58,402)	(62,084)	(65,700)	(69,443)	(69,403)	(71,001)	(78,431)	(85,980)	(90,225)	(95,047)	(99,818)	(71,278)
Net Cashflow	-	-	-	-	-	-	3,717	6,356	3,001	(355)	(367)	(380)	(393)	(11,578)
Cash Balance B/f	-	-	-	-	-	-	-	4,272	16,915	26,264	25,558	24,909	24,070	23,287
Cash Balance C/f	-	-	-	-	-	-	4,272	16,915	26,264	25,558	24,909	24,070	23,287	-
Cash Balance < 0														

Profit & Loss Statement

Profit & Loss Statement			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Revenue	3,672,400	3,672,400	-	-	47,143	95,935	99,293	102,768	106,365	110,088	113,941	117,929	122,057	126,329	130,750	135,326
Operating Cost	(2,010,755)	(2,010,755)	-	-	(34,824)	(69,453)	(70,367)	(70,923)	(71,696)	(72,500)	(73,530)	(74,190)	(75,080)	(76,001)	(77,127)	(77,866)
Rehab Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	1,661,645	1,661,645	-	-	12,319	26,482	28,926	31,845	34,669	37,588	40,411	43,739	46,977	50,327	53,623	57,460
Depreciation	(189,235)	(189,235)	-	-	(9,974)	(19,949)	(19,949)	(13,780)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)
EBIT	1,472,410	1,472,410	-	-	2,344	6,534	8,978	18,065	27,058	29,977	32,800	36,128	39,366	42,716	46,012	49,849
Interest Income	1,458	1,458	-	-	28	84	115	151	175	130	76	56	56	56	57	-
Interest Payable (Cash Basis	(54,822)	(54,822)	-	-	(4,694)	(8,829)	(8,171)	(7,412)	(6,617)	(5,759)	(4,847)	(3,832)	(2,751)	(1,584)	(326)	0
Net FX Swaps Gain/(Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBT	1,419,046	1,419,046	-	-	(2,321)	(2,211)	922	10,804	20,616	24,349	28,030	32,353	36,671	41,188	45,742	49,849
Corporate Tax Expense	(218,409)	(218,409)	-	-	-	-	-	-	-	-	(5,105)	(5,777)	(6,425)	(7,102)	(7,785)	(8,401)
Deferred Tax Expense	0	0	-	-	(577)	(1,519)	(1,989)	(2,546)	(3,092)	(3,652)	900	924	924	924	924	924
NPAT	1,200,638	1,200,638	-	-	(2,898)	(3,730)	(1,067)	8,258	17,524	20,696	23,825	27,500	31,170	35,010	38,881	42,372
Distributions	(1,220,459)	(1,220,459)	-	-	-	-	-	(563)	(17,524)	(20,696)	(17,240)	(13,823)	(16,406)	(19,071)	(42,346)	(48,807)
Retained Earnings	(19,822)	(19,822)	-	-	(2,898)	(3,730)	(1,067)	7,695	-	-	6,586	13,677	14,765	15,939	(3,465)	(6,435)
Retained Earnings B/f			-	-	-	(2,898)	(6,628)	(7,695)	-	-	-	6,586	20,262	35,027	50,966	47,501
Retained Earnings C/f			-	-	(2,898)	(6,628)	(7,695)	-	-	-	6,586	20,262	35,027	50,966	47,501	41,066

Profit & Loss Statement	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Revenue	140,063	144,965	150,039	155,290	160,725	166,351	172,173	178,199	184,436	190,891	197,572	204,487	211,644	107,642
Operating Cost	(78,888)	(79,944)	(81,258)	(82,166)	(83,335)	(84,545)	(86,030)	(87,092)	(88,434)	(89,822)	(91,507)	(92,747)	(94,288)	(47,143)
Rehab Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	61,175	65,021	68,781	73,124	77,390	81,806	86,143	91,107	96,002	101,069	106,065	111,741	117,356	60,499
Depreciation	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(7,611)	(3,806)	-	-	-	-	-
EBIT	53,564	57,410	61,169	65,513	69,779	74,195	78,532	83,496	92,197	101,069	106,065	111,741	117,356	60,499
Interest Income	-	-	-	-	-	-	2	34	76	84	82	79	77	37
Interest Payable (Cash Basis	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net FX Swaps Gain/(Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBT	53,564	57,410	61,169	65,513	69,779	74,195	78,534	83,530	92,272	101,153	106,147	111,820	117,433	60,537
Corporate Tax Expense	(8,959)	(9,536)	(10,100)	(10,751)	(11,391)	(12,053)	(12,704)	(13,454)	(14,303)	(15,173)	(15,922)	(16,773)	(17,615)	(9,080)
Deferred Tax Expense	924	924	924	924	924	924	924	924	462	-	-	-	-	0
NPAT	45,529	48,798	51,994	55,686	59,312	63,066	66,754	71,001	78,431	85,980	90,225	95,047	99,818	51,456
Distributions	(51,956)	(55,216)	(58,402)	(62,084)	(65,700)	(69,443)	(69,403)	(71,001)	(78,431)	(85,980)	(90,225)	(95,047)	(99,818)	(71,278)
Retained Earnings	(6,427)	(6,418)	(6,408)	(6,398)	(6,388)	(6,378)	(2,649)	-	-	-	-	-	-	(19,822)
Retained Earnings B/f	41,066	34,639	28,222	21,813	15,415	9,027	2,649	0	0	0	0	0	0	0
Retained Earnings C/f	34,639	28,222	21,813	15,415	9,027	2,649	0	0	0	0	0	0	0	(19,822)

Balance Sheet

Balance Sheet	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Current Assets														
Cash	-	-	0	6,400	9,939	16,333	16,661	9,655	-	-	-	-	-	-
Trade Debtors	-	-	-	7,814	8,043	8,370	8,663	8,966	9,229	9,605	9,941	10,289	10,591	11,022
Deferred Tax Asset	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve A/c	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c	-	-	8,709	8,661	8,678	8,666	8,668	8,671	8,682	8,676	8,679	8,681	8,686	-
Working Capital Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Control Account	3,139	4,082	274	(322)	(350)	(388)	(423)	(459)	(491)	(534)	(574)	(616)	(653)	(703)
Total	3,139	4,082	8,983	22,552	26,310	32,982	33,570	26,834	17,420	17,747	18,046	18,355	18,624	10,319
Non-Current Assets														
Major Equipment	18,031	90,835	98,330	93,414	88,497	83,581	78,664	73,748	68,831	63,915	58,998	54,082	49,165	44,249
Balance of Plant	1,187	23,525	29,008	27,557	26,107	24,656	23,206	21,756	20,305	18,855	17,405	15,954	14,504	13,053
Grid / Step up	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non Tax Deductible	8,006	27,074	37,012	24,675	12,337	0	0	0	0	0	0	0	0	0
Deductible Financing Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IDC/Insurance	17,408	20,379	24,885	23,640	22,396	21,152	19,908	18,663	17,419	16,175	14,931	13,687	12,442	11,198
Total	44,632	161,813	189,235	169,286	149,338	129,389	121,778	114,167	106,556	98,945	91,334	83,722	76,111	68,500
Liabilities														
Trade Creditors	-	-	-	(5,679)	(5,737)	(5,798)	(5,860)	(5,925)	(5,992)	(6,062)	(6,134)	(6,208)	(6,285)	(6,359)
Tax Creditors	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Liability	-	-	-	(1,274)	(3,008)	(5,287)	(8,103)	(11,470)	(12,938)	(12,013)	(11,089)	(10,165)	(9,241)	(8,317)
Senior Debt Facility	-	(86,607)	(118,930)	(110,713)	(101,848)	(92,265)	(81,918)	(70,746)	(58,687)	(45,660)	(31,592)	(16,402)	0	-
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezzanine Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	(86,607)	(118,930)	(117,666)	(110,594)	(103,350)	(95,882)	(88,142)	(77,617)	(63,735)	(48,815)	(32,775)	(15,526)	(14,676)
Net Assets	47,771	79,288	79,288	74,172	65,054	59,021	59,466	52,859	46,359	52,957	60,564	69,302	79,209	64,143
Equity														
Share Capital	11,943	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822
S/h Loan	35,829	59,466	59,466	59,466	52,859	46,252	39,645	33,037	26,430	19,823	13,215	6,608	(0)	(0)
Retained Earnings	-	-	-	(5,116)	(7,627)	(7,053)	-	-	107	13,312	27,527	42,873	59,387	44,321
Total	47,771	79,288	79,288	74,172	65,054	59,021	59,466	52,859	46,359	52,957	60,564	69,302	79,209	64,143
Balance Sheet Check 1 (Ok)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance Sheet Check 2 (Ok)		-	-	-	-	-	-	-	-	-	-	-	-	-
IFS -> AFS Links (Ok)														

Balance Sheet	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Current Assets														
Cash	-	-	-	-	-	-	554	6,842	13,190	12,839	12,557	12,099	11,710	-
Trade Debtors	11,408	11,807	12,153	12,648	13,091	13,549	13,946	14,514	15,022	15,548	16,003	16,655	17,238	-
Deferred Tax Asset	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve A/c	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Control Account	(749)	(796)	(840)	(896)	(949)	(1,003)	(1,054)	(1,118)	(1,178)	(1,240)	(1,299)	(1,372)	(1,441)	-
Total	10,659	11,011	11,313	11,752	12,142	12,546	13,447	20,239	27,034	27,146	27,262	27,382	27,507	-
Non-Current Assets														
Major Equipment	39,332	34,416	29,499	24,583	19,666	14,750	9,833	4,917	0	0	0	0	0	0
Balance of Plant	11,603	10,153	8,702	7,252	5,802	4,351	2,901	1,450	0	0	0	0	0	0
Grid / Step up	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non Tax Deductible	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deductible Financing Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IDC/Insurance	9,954	8,710	7,465	6,221	4,977	3,733	2,488	1,244	0	0	0	0	0	0
Total	60,889	53,278	45,667	38,056	30,445	22,833	15,222	7,611	0	0	0	0	0	0
Liabilities														
Trade Creditors	(6,441)	(6,526)	(6,615)	(6,706)	(6,800)	(6,898)	(6,999)	(7,104)	(7,212)	(7,324)	(7,440)	(7,560)	(7,685)	-
Tax Creditors	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Liability	(7,393)	(6,469)	(5,545)	(4,621)	(3,696)	(2,772)	(1,848)	(924)	(0)	(0)	(0)	(0)	(0)	(0)
Senior Debt Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezzanine Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(13,834)	(12,995)	(12,159)	(11,327)	(10,497)	(9,670)	(8,847)	(8,028)	(7,212)	(7,324)	(7,440)	(7,560)	(7,685)	(0)
Net Assets	57,714	51,293	44,820	38,481	32,090	25,709	19,822	19,822	19,822	19,822	19,822	19,822	19,822	0
Equity														
Share Capital	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822	19,822
S/h Loan	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	37,892	31,471	24,999	18,659	12,268	5,887	-	-	-	-	-	-	-	(19,822)
Total	57,714	51,293	44,820	38,481	32,090	25,709	19,822	19,822	19,822	19,822	19,822	19,822	19,822	(0)
Balance Sheet Check 1 (Ok)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance Sheet Check 2 (Ok)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IFS -> AFS Links (Ok)														

Summary Graphs

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Debt Ratios Vs. Breach Ratios															
DSCR	x	0.00x	0.00x	1.25x	1.52x	1.66x	1.83x	1.99x	2.16x	2.02x	2.18x	2.32x	2.48x	0.00x	0.00x
LLCR	x	0.00x	0.00x	1.93x	2.02x	2.10x	2.17x	2.22x	2.26x	2.31x	2.39x	2.47x	2.55x	0.00x	0.00x
Lock Up DSCR	x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x
Lock Up LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default DSCR	x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x
Debt/(Debt+Equity)															
Both Senior	USD '000	-	86,607	114,914	106,374	97,161	87,203	76,450	64,839	52,306	38,766	24,146	8,360	-	-
Equity	USD '000	47,771	79,288	76,390	69,357	61,682	62,770	56,163	49,556	49,534	56,603	64,760	74,092	67,323	60,888
Both Senior	%	0.00%	52.21%	60.07%	60.53%	61.17%	58.15%	57.65%	56.68%	51.36%	40.65%	27.16%	10.14%	0.00%	0.00%
Equity	%	100.00%	47.79%	39.93%	39.47%	38.83%	41.85%	42.35%	43.32%	48.64%	59.35%	72.84%	89.86%	100.00%	100.00%
Gas Tariff & Volumes															
Nominal Energy Tariff	USD / Ton	0	0	221	229	237	245	253	262	272	281	291	301	312	323
Nominal Energy Tariff	USD / Mmbtu	0.00	0.00	4.54	4.69	4.86	5.03	5.21	5.39	5.58	5.77	5.97	6.18	6.40	6.62
Nominal Capacity Charge	USD / Ton / Annum	0	0	47	49	51	52	54	56	58	60	62	64	66	69
Nominal Capacity Charge	USD / Mmbtu / Annum	0.00	0.00	0.97	1.00	1.04	1.07	1.11	1.15	1.19	1.23	1.27	1.32	1.37	1.41
LNG throughput	MTPA	0.00000	0.00000	0.06143	0.12744	0.13169	0.13478	0.13907	0.14299	0.14729	0.15134	0.15563	0.16054	0.16589	0.16905
Annual Energy Fees	USD '000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Capacity Fees	USD '000	-	-	47,143	95,935	99,293	102,768	106,365	110,088	113,941	117,929	122,057	126,329	130,750	135,326
LNG coming in															

		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Debt Ratios Vs. Breach Ratios															
DSCR	x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x
LLCR	x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x
Lock Up DSCR	x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x
Lock Up LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default DSCR	x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x
Debt/(Debt+Equity)															
Both Senior	USD '000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity	USD '000	54,461	48,043	41,635	35,237	28,849	22,471	19,822	19,822	19,822	19,822	19,822	19,822	19,822	(0)
Both Senior	%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							
Equity	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%							
Gas Tariff & Volumes															
Nominal Energy Tariff	USD / Ton	334	345	358	370	383	396	410	425	440	455	471	487	504	0
Nominal Energy Tariff	USD / Mmbtu	6.85	7.09	7.34	7.60	7.87	8.14	8.43	8.72	9.03	9.34	9.67	10.01	10.36	0.00
Nominal Capacity Charge	USD / Ton / Annum	71	74	76	79	82	85	88	91	94	97	100	104	108	0
Nominal Capacity Charge	USD / Mmbtu / Annum	1.46	1.51	1.57	1.62	1.68	1.74	1.80	1.86	1.93	1.99	2.06	2.14	2.21	0.00
LNG throughput	MTPA	0.17637	0.18144	0.18685	0.18579	0.18608	0.18600	0.18640	0.18534	0.18563	0.18555	0.18595	0.18505	0.18644	0.09244
Annual Energy Fees	USD '000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Capacity Fees	USD '000	140,063	144,965	150,039	155,290	160,725	166,351	172,173	178,199	184,436	190,891	197,572	204,487	211,644	107,642
LNG coming in															

Appendix 4 100MW Power Plant Model AFS

Project & Sponsor:	Mauritius LNG Power | Central Ene	Equity IRRs	Scenario	Base Case Gross
Purpose & Status:	Viability Assesment | Draft	Nom: 20%	Valid?	-
Sheet:	AFS	Real: 16.1%	Breach?	1

Financial Statements (USD '000)

	01-Jan-17	01-Jan-17	01-Jan-17	01-Jan-18	01-Jan-19	01-Jan-20	01-Jan-21	01-Jan-22	01-Jan-23	01-Jan-24	01-Jan-25	01-Jan-26	01-Jan-27	01-Jan-28	01-Jan-29	01-Jan-30	01-Jan-31	01-Jan-32	01-Jan-33	01-Jan-34	01-Jan-35	01-Jan-36	01-Jan-37	01-Jan-38	01-Jan-39	01-Jan-40	01-Jan-41	01-Jan-42	01-Jan-43
			31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	31-Dec-21	31-Dec-22	31-Dec-23	31-Dec-24	31-Dec-25	31-Dec-26	31-Dec-27	31-Dec-28	31-Dec-29	31-Dec-30	31-Dec-31	31-Dec-32	31-Dec-33	31-Dec-34	31-Dec-35	31-Dec-36	31-Dec-37	31-Dec-38	31-Dec-39	31-Dec-40	31-Dec-41	31-Dec-42	31-Dec-43
			2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Cashflows			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Revenue																													
Energy	4,529,077	4,529,077	-	-	117,131	121,246	124,995	129,037	132,738	137,051	141,959	146,546	151,492	157,634	165,009	171,669	176,598	182,341	188,876	194,983	201,570	208,082	214,509	221,440	227,787	237,073	249,504	260,068	269,739
Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Income	984	984	-	-	56	59	50	50	50	51	50	50	50	51	25	0	0	0	0	0	0	0	8	48	81	80	77	75	72
Total	4,530,061	4,530,061	-	-	117,186	121,305	125,045	129,087	132,789	137,101	142,009	146,596	151,542	157,685	165,034	171,669	176,598	182,341	188,876	194,983	201,570	208,082	214,517	221,489	227,867	237,153	249,581	260,143	269,811
Period on Period %				0.00%	0.00%	3.51%	3.08%	3.23%	2.87%	3.25%	3.58%	3.23%	3.37%	4.05%	4.66%	4.02%	2.87%	3.25%	3.58%	3.23%	3.38%	3.23%	3.09%	3.25%	2.88%	4.08%	5.24%	4.23%	3.72%
OpEx																													
Fixed	(52,498)	(52,498)	-	-	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)	(2,104)	(2,099)	(2,099)	(2,099)
Variable	(3,106,323)	(3,106,323)	-	-	(92,218)	(93,964)	(95,990)	(96,091)	(99,807)	(102,050)	(104,752)	(107,025)	(109,168)	(112,269)	(116,512)	(119,017)	(120,715)	(122,692)	(126,922)	(130,396)	(134,215)	(137,745)	(141,610)	(145,286)	(148,620)	(153,572)	(160,958)	(166,140)	(168,590)
Site Rental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agency Fees (Ops.)	(628)	(628)	-	-	(53)	(55)	(57)	(59)	(61)	(64)	(66)	(68)	(70)	(73)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(3,159,448)	(3,159,448)	-	-	(94,370)	(96,124)	(98,146)	(98,249)	(101,967)	(104,218)	(106,916)	(109,191)	(111,336)	(114,446)	(118,610)	(121,116)	(122,814)	(124,796)	(129,020)	(132,495)	(136,313)	(139,850)	(143,708)	(147,384)	(150,718)	(155,676)	(163,056)	(168,239)	(170,688)
Period on Period %				0.00%	0.00%	1.86%	2.10%	0.10%	3.78%	2.21%	2.59%	2.13%	1.96%	2.79%	3.64%	2.11%	1.40%	1.61%	3.38%	2.69%	2.88%	2.59%	2.76%	2.56%	2.26%	3.29%	4.74%	3.18%	1.46%
Working Capital Adjustments																													
Debtors	-	-	-	-	(9,710)	(286)	(323)	(334)	(267)	(433)	(367)	(379)	(426)	(574)	(631)	(444)	(356)	(576)	(489)	(504)	(567)	(491)	(554)	(572)	(458)	(1,052)	(980)	(727)	21,500
Creditors	-	-	-	-	7,757	101	176	8	276	241	192	186	188	302	356	131	104	231	311	284	328	258	331	301	230	591	574	330	(13,790)
VAT	-	-	-	-	298	28	22	50	(1)	29	27	29	36	41	42	48	38	53	27	34	36	35	34	41	35	70	62	60	(1,176)
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Adjustment	-	-	-	-	(1,656)	(157)	(125)	(276)	7	(162)	(148)	(163)	(201)	(231)	(233)	(266)	(213)	(292)	(150)	(186)	(202)	(197)	(189)	(230)	(193)	(391)	(344)	(336)	6,534
Operating Cashflows	1,370,613	1,370,613	-	-	21,160	25,025	26,774	30,563	30,829	32,722	34,945	37,242	40,004	43,008	46,191	50,287	53,571	57,252	59,705	62,302	65,054	68,035	70,620	73,875	76,956	81,086	86,180	91,568	105,657
CapEx																													
Construction Costs	(156,523)	(156,523)	(156,160)	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Land Purchase /Lease	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility IDC	(11,061)	(11,061)	(5,748)	(5,314)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Up Front Fees	(1,595)	(1,595)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senior Debt Facility Commitment Fees (incl. Agency	(332)	(332)	(237)	(96)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Up Front Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2 Commitment Fees (incl. Agency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt IDC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DoE Development Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Paid	(23,528)	(23,528)	(23,460)	(69)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve Initial Fundin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c Initial Funding	(7,759)	(7,759)	-	(7,759)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(200,800)	(200,800)	(187,200)	(13,600)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Funding																													
Senior Debt Facility	106,366	106,366	93,582	12,784	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Equity	70,910	70,910	70,910	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezz Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Refund	23,528	23,528	22,707	817	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	200,805	200,805	187,200	13,600	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow After Funding	1,370,617	1,370,617	(0)	-	21,165	25,025	26,774	30,563	30,829	32,722	34,945	37,242	40,004	43,008	46,191	50,287	53,571	57,252	59,705	62,302	65,054	68,035	70,620	73,875	76,956	81,086	86,180	91,568	105,657
Tax	(173,626)	(173,626)	-	-	-	-	-	-	-	-	-	(4,776)	(5,736)	(6,353)	(6,961)	(7,581)	(8,065)	(8,629)	(8,976)	(9,371)	(9,786)	(10,232)	(10,619)	(11,113)	(11,572)	(12,222)	(12,979)	(13,786)	(14,868)
Net FX Swaps Gain/(Loss)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Maintenance Reserve	1,196,991	1,196,991	(0)	-	21,165	25,025	26,774	30,563	30,829	32,722	34,945	32,465	34,268	36,655	39,230	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Major Maintenance Reserve																													
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Maintenance Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve																													
Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CFADS	1,196,991	1,196,991	(0)	-	21,165	25,025	26,774	30,563	30,829	32,722	34,945	32,465	34,268	36,655	39,230	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Senior Debt Service																													
Interest	(49,004)	(49,004)	-	-	(8,183)	(7,619)	(6,964)	(6,280)	(5,542)	(4,759)	(3,884)	(2,954)	(1,950)	(869)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Principal	(106,366)	(106,366)	-	-	(7,349)	(7,928)	(8,570)	(9,254)	(9,992)	(10,785)	(11,652)	(12,581)	(13,585)	(14,670)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(155,370)	(155,370)	-	-	(15,533)	(15,547)	(15,534)	(15,534)	(15,534)	(15,543)	(15,535)	(15,535)	(15,535)	(15,539)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Cashflow Available for DSRA/c	1,041,621	1,041,621	(0)	-	5,632	9,478	11,240	15,029	15,295	17,179	19,409	16,930	18,733	21,116	39,230	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Debt Service Reserve Account																													
Addition	(60)	(60)	-	-	(14)	-	(12)	(11)	(9)	(0)	(6)	(5)	(3)	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	-	(0)	(0)	(0)	-	(0)	(0)	(0)
Release for Shortfall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Release for Excess Target	7,820	7,820	-	-	-	-	13	11	10	0	7	6	4	0	7,769	0	0	-	0	0	0	-	0	0	0	-	0	0	0
Total	7,759	7,759	-	-	(14)	-	1	1	1	-	1	1	1	(0)	7,769	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Mezz Debt	1,049,380	1,049,380	(0)	-	5,617	9,478	11,241	15,029	15,295	17,179	19,410	16,931	18,734	21,116	46,999	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Mezzanine Debt																													
Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Senior Cashsweep	1,049,380	1,049,380	(0)	-	5,617	9,478	11,241	15,029	15,295	17,179	19,410	16,931	18,734	21,116	46,999	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Senior Cashsweep																													
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashsweep to Principal Repayment: Senior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for S/h Loan	1,049,380	1,049,380	(0)	-	5,617	9,478	11,241	15,029	15,295	17,179	19,410	16,931	18,734	21,116	46,999	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
S/h Loan																													
Interest	(0)	(0)	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Principal	(53,183)	(53,183)	-	-	-	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total	(53,183)	(53,183)	-	-	(0)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	(5,909)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cashflow Available for Equity	996,197	996,197	(0)	-	5,617	3,568	5,332	9,120	9,386	11,269	13,501	11,021	12,825	15,207	46,999	42,707	45,506	48,623	50,729	52,931	55,268	57,803	60,001	62,761	65,383	68,865	73,201	77,782	90,789
Equity Plug During Operations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dividends (before Dividend Tax	(996,197)	(996,197)	-	-	(3,659)	(5,526)	(5,332)	(9,120)	(9,386)	(11,269)	(13,501)	(11,021)	(12,825)	(15,207)	(46,999)	(42,707)	(45,506)	(48,623)	(50,729)	(52,931)	(55,268)	(57,803)	(54,290)	(56,015)	(65,577)	(69,256)	(73,546)	(78,118)	(101,982)
Net Cashflow	0	0	(0)	-	1,958	(1,958)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,711	6,747	(193)	(391)	(344)	(336)	(11,194)
Cash Balance B/f			12,197	-	1,598	2,674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,146	21,645	24,714	24,146	23,407	22,657
Cash Balance C/f			12,197	-	3,556	716	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,146	21,645	24,714	24,146	23,407	22,657	10,979
Cash Balance < 0		0 Breach(es)																											

Profit & Loss Statement

Profit & Loss Statement			2017	2018	2019	2020	2021	2022	2023	2024
Revenue	4,529,077	4,529,077	-	-	117,131	121,246	124,995	129,037	132,738	137,051
Operating Cost	(3,159,448)	(3,159,448)	-	-	(94,370)	(96,124)	(98,146)	(98,249)	(101,967)	(104,218)
Rehab Cost	-	-	-	-	-	-	-	-	-	-
EBITDA	1,369,628	1,369,628	-	-	22,760	25,122	26,848	30,788	30,771	32,833
			0%	*0%*	*19%*	*21%*	*21%*	*24%*	*23%*	*24%*
Depreciation	(169,513)	(169,513)	-	-	(10,009)	(10,009)	(10,009)	(8,205)	(8,205)	(8,205)
EBIT	1,200,116	1,200,116	-	-	12,751	15,113	16,840	22,583	22,566	24,628
Interest Income	984	984	-	-	56	59	50	50	50	51
Interest Payable (Cash Basis	(49,004)	(49,004)	-	-	(8,183)	(7,619)	(6,964)	(6,280)	(5,542)	(4,759)
Net FX Swaps Gain/(Loss)	-	-	-	-	-	-	-	-	-	-
EBT	1,152,096	1,152,096	-	-	4,623	7,554	9,926	16,353	17,075	19,920
Corporate Tax Expense	(173,626)	(173,626)	-	-	-	-	-	-	-	-
Deferred Tax Expense	0	(0)	-	-	(964)	(1,404)	(1,759)	(2,453)	(2,561)	(2,988)
NPAT	978,469	978,469	-	-	3,659	6,150	8,166	13,900	14,513	16,932
Distributions	(996,197)	(996,197)	-	-	(3,659)	(5,526)	(5,332)	(9,120)	(9,386)	(11,269)
Retained Earnings	(17,728)	(17,728)	-	-	-	624	2,835	4,780	5,127	5,663
Retained Earnings B/f			-	-	-	-	624	3,458	8,238	13,365
Retained Earnings C/f			-	-	-	624	3,458	8,238	13,365	19,028
Retained Earnings Check	Ok		-	-	-	-	-	-	-	-

Profit & Loss Statement	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Revenue	141,959	146,546	151,492	157,634	165,009	171,669	176,598	182,341	188,876	194,983	201,570	208,082	214,509	221,440	227,787	237,073	249,504	260,068	269,739
Operating Cost	(106,916)	(109,191)	(111,336)	(114,446)	(118,610)	(121,116)	(122,814)	(124,796)	(129,020)	(132,495)	(136,313)	(139,850)	(143,708)	(147,384)	(150,718)	(155,676)	(163,056)	(168,239)	(170,688)
Rehab Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	35,042	37,354	40,155	43,188	46,399	50,553	53,785	57,544	59,855	62,489	65,257	68,232	70,801	74,056	77,068	81,397	86,447	91,829	99,051
	25%	*25%*	*27%*	*27%*	*28%*	*29%*	*30%*	*32%*	*32%*	*32%*	*32%*	*33%*	*33%*	*33%*	*34%*	*34%*	*35%*	*35%*	*37%*
Depreciation	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	(8,205)	-	-	-	-	-
EBIT	26,837	29,149	31,950	34,983	38,194	42,348	45,580	49,339	51,650	54,283	57,051	60,027	62,596	65,851	77,068	81,397	86,447	91,829	99,051
Interest Income	50	50	50	51	25	0	0	0	0	0	0	0	8	48	81	80	77	75	72
Interest Payable (Cash Basis	(3,884)	(2,954)	(1,950)	(869)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net FX Swaps Gain/(Loss)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBT	23,004	26,246	30,051	34,164	38,219	42,348	45,580	49,339	51,650	54,283	57,051	60,027	62,604	65,900	77,149	81,477	86,525	91,904	99,123
Corporate Tax Expense	-	(4,776)	(5,736)	(6,353)	(6,961)	(7,581)	(8,065)	(8,629)	(8,976)	(9,371)	(9,786)	(10,232)	(10,619)	(11,113)	(11,572)	(12,222)	(12,979)	(13,786)	(14,868)
Deferred Tax Expense	(3,451)	840	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	-	-	-	-	-
NPAT	19,553	22,309	25,543	29,040	32,486	35,996	38,743	41,938	43,903	46,141	48,494	51,023	53,214	56,015	65,577	69,256	73,546	78,118	84,255
Distributions	(13,501)	(11,021)	(12,825)	(15,207)	(46,999)	(42,707)	(45,506)	(48,623)	(50,729)	(52,931)	(55,268)	(57,803)	(54,290)	(56,015)	(65,577)	(69,256)	(73,546)	(78,118)	(101,982)
Retained Earnings	6,052	11,287	12,719	13,833	(14,513)	(6,711)	(6,763)	(6,685)	(6,827)	(6,790)	(6,774)	(6,780)	(1,076)	-	-	-	-	-	(17,728)
Retained Earnings B/f	19,028	25,080	36,368	49,086	62,919	48,406	41,695	34,932	28,247	21,421	14,630	7,856	1,076	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings C/f	25,080	36,368	49,086	62,919	48,406	41,695	34,932	28,247	21,421	14,630	7,856	1,076	(0)	(0)	(0)	(0)	(0)	(0)	(17,728)
Retained Earnings Check	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Balance Sheet

Balance Sheet	2017	2018	2019	2020	2021	2022	2023	2024
Current Assets								
Cash	-	-	1,958	-	-	-	-	-
Trade Debtors	-	-	9,710	9,997	10,320	10,654	10,921	11,353
Deferred Tax Asset	-	-	-	-	-	-	-	-
Major Maintenance Reserve A/c	-	-	-	-	-	-	-	-
Rehab Reserve	-	-	-	-	-	-	-	-
DSRA/c	-	7,759	7,774	7,774	7,773	7,772	7,772	7,772
Working Capital Account	-	-	-	-	-	-	-	-
VAT Control Account	752	4	(298)	(326)	(349)	(398)	(397)	(426)
Total	752	7,764	19,144	17,444	17,744	18,028	18,296	18,699
Non-Current Assets								
Major Equipment	152,388	152,388	144,769	137,149	129,530	121,910	114,291	106,672
Balance of Plant	319	319	303	287	271	255	239	223
Grid / Step up	-	-	-	-	-	-	-	-
Spare4	-	-	-	-	-	-	-	-
Spare5	-	-	-	-	-	-	-	-
Intangible	-	-	-	-	-	-	-	-
Non Tax Deductible	5,048	5,411	3,608	1,804	-	-	-	-
Deductible Financing Fees	-	-	-	-	-	-	-	-
IDC/Insurance	5,985	11,394	10,824	10,255	9,685	9,115	8,545	7,976
Total	163,740	169,513	159,504	149,495	139,486	131,281	123,076	114,871
Liabilities								
Trade Creditors	-	-	(7,757)	(7,858)	(8,035)	(8,043)	(8,319)	(8,560)
Tax Creditors	-	-	-	-	-	-	-	-
Deferred Tax Liability	-	-	(964)	(2,368)	(4,127)	(6,580)	(9,141)	(12,129)
Senior Debt Facility	(93,582)	(106,366)	(99,016)	(91,088)	(82,518)	(73,265)	(63,273)	(52,488)
Spare 2	-	-	-	-	-	-	-	-
Mezzanine Facility	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-
Total	(93,582)	(106,366)	(107,737)	(101,314)	(94,680)	(87,888)	(80,732)	(73,177)
Net Assets	70,910	70,910	70,910	65,625	62,550	61,421	60,639	60,393
Equity								
Share Capital	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728
S/h Loan	53,183	53,183	53,183	47,274	41,364	35,455	29,546	23,637
Retained Earnings	-	-	-	624	3,458	8,238	13,365	19,028
Total	70,910	70,910	70,910	65,625	62,550	61,421	60,639	60,393

Balance Sheet	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Current Assets																			
Cash	-	-	-	-	-	-	-	-	-	-	-	-	5,711	12,458	12,265	11,874	11,530	11,194	-
Trade Debtors	11,720	12,099	12,525	13,098	13,729	14,174	14,530	15,105	15,594	16,098	16,665	17,156	17,710	18,282	18,741	19,793	20,773	21,500	-
Deferred Tax Asset	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Maintenance Reserve A/c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rehab Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSRA/c	7,771	7,770	7,769	7,769	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VAT Control Account	(453)	(482)	(518)	(560)	(602)	(649)	(688)	(740)	(767)	(801)	(837)	(873)	(907)	(948)	(983)	(1,053)	(1,115)	(1,176)	-
Total	19,039	19,387	19,776	20,308	13,128	13,524	13,842	14,365	14,827	15,297	15,828	16,283	22,515	29,792	30,022	30,613	31,187	31,517	0
Non-Current Assets																			
Major Equipment	99,052	91,433	83,813	76,194	68,575	60,955	53,336	45,716	38,097	30,478	22,858	15,239	7,619	0	0	0	0	0	0
Balance of Plant	207	192	176	160	144	128	112	96	80	64	48	32	16	-	-	-	-	-	-
Grid / Step up	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spare5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Intangible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non Tax Deductible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deductible Financing Fees	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IDC/Insurance	7,406	6,836	6,267	5,697	5,127	4,558	3,988	3,418	2,848	2,279	1,709	1,139	570	0	0	0	0	0	0
Total	106,666	98,461	90,256	82,051	73,846	65,640	57,435	49,230	41,025	32,820	24,615	16,410	8,205	0	0	0	0	0	0
Liabilities																			
Trade Creditors	(8,752)	(8,939)	(9,127)	(9,428)	(9,784)	(9,915)	(10,019)	(10,250)	(10,562)	(10,846)	(11,174)	(11,432)	(11,764)	(12,065)	(12,295)	(12,886)	(13,459)	(13,790)	-
Tax Creditors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Liability	(15,580)	(14,740)	(13,512)	(12,284)	(11,055)	(9,827)	(8,599)	(7,370)	(6,142)	(4,913)	(3,685)	(2,457)	(1,228)	(0)	(0)	(0)	(0)	(0)	(0)
Senior Debt Facility	(40,836)	(28,255)	(14,670)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Spare 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mezzanine Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Capital Facility	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(65,169)	(51,934)	(37,308)	(21,712)	(20,840)	(19,742)	(18,618)	(17,621)	(16,704)	(15,760)	(14,859)	(13,889)	(12,992)	(12,065)	(12,295)	(12,886)	(13,459)	(13,790)	(0)
Net Assets	60,536	65,914	72,723	80,647	66,134	59,423	52,660	45,975	39,148	32,358	25,584	18,804	17,728	17,728	17,728	17,728	17,728	17,728	0
Equity																			
Share Capital	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728	17,728
S/h Loan	17,728	11,818	5,909	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	25,080	36,368	49,086	62,919	48,406	41,695	34,932	28,247	21,421	14,630	7,856	1,076	-	-	-	-	-	-	(17,728)
Total	60,536	65,914	72,723	80,647	66,134	59,423	52,660	45,975	39,148	32,358	25,584	18,804	17,728	17,728	17,728	17,728	17,728	17,728	(0)

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Balance Sheet Check 1	Ok	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance Sheet Check 2	Ok		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IFS -> AFS Links	Ok																											

Summary Graphs

Tariffs - partial and fully indexed

	Unit	Input	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Partial																													
Peak	USD/Kwh	-																											
Standard	USD/Kwh	100.00%																											
Off Peak	USD/Kwh	-																											
Weighted Avg. Tariff	USD/Kwh																												
Fully indexed																													
Peak	USD/Kwh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard	USD/Kwh		-	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.38	0.39	0.40	0.42	0.43	0.45	0.46	0.48	0.50	0.51	0.53	0.55	0.57	0.59	0.61	0.63	0.65	-
Off Peak	USD/Kwh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Weighted Avg. Tariff	USD/Kwh		-	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.38	0.39	0.40	0.42	0.43	0.45	0.46	0.48	0.50	0.51	0.53	0.55	0.57	0.59	0.61	0.63	0.65	-

Debt Ratios Vs. Breach Ratios

	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DSCR	x	0.00x	1.21x	1.54x	1.67x	1.84x	1.99x	2.03x	2.18x	2.19x	2.13x	2.28x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x
LLCR	x	0.00x	1.90x	1.99x	2.05x	2.12x	2.15x	2.19x	2.22x	2.21x	2.28x	2.36x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x	0.00x
Lock Up DSCR	x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x	1.20x
Lock Up LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default LLCR	x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x	1.30x
Default DSCR	x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x	1.10x

Debt/(Debt+Equity)

	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Both Senior	USD '000	93,582	102,758	95,129	86,882	77,977	68,361	57,984	46,772	34,665	21,592	7,476	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equity	USD '000	70,910	72,232	67,956	64,016	61,985	60,888	60,429	60,378	62,837	69,123	76,439	69,402	62,738	55,999	49,229	42,449	35,653	28,860	22,071	17,728	17,728	17,728	17,728	17,728	17,728	17,728	(0)
Both Senior	%	56.89%	58.72%	58.33%	57.58%	55.71%	52.89%	48.97%	43.65%	35.55%	23.80%	8.91%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						
Equity	%	43.11%	41.28%	41.67%	42.42%	44.29%	47.11%	51.03%	56.35%	64.45%	76.20%	91.09%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%						

LNG Calculations

	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Annual Quantity	Mmbtu p.a	-	-	2,874,333	2,878,379	2,870,795	2,867,080	2,853,331	2,849,757	2,855,878	2,852,125	2,852,323	2,871,048	2,903,845	2,919,083	2,901,439	2,894,166	2,896,735	2,889,285	2,885,843	2,878,265	2,866,937	2,859,488	2,842,054	2,857,397	2,905,730	2,926,526	2,932,657
Annual Quantity	MTPA	-	-	0.0584	0.0584	0.0583	0.0582	0.0579	0.0579	0.0580	0.0579	0.0579	0.0583	0.0590	0.0593	0.0589	0.0588	0.0588	0.0587	0.0586	0.0584	0.0582	0.0581	0.0577	0.0580	0.0590	0.0594	0.0595
Cost per uint	USD/Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regas cost per uin	USD/Mmbtu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total cost p.a	USD '000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix 5 LNG Terminal & 100MW Power Plant Financial Model – Inputs

Project	Mauritius LNG Terminal
Document Purpose	The purpose of this document is to list the key project assumptions: - Technical - Financial - Market - Production In a non excel based format for the client / technical advisor / market advisor confirmation and sign off
Key CRESCO Contact	Francois Viljoen
Excel file	20140716.1.LNG.Terminal.xlsm
Version	1
Date	18 Jul. 14

CRESCO Scope:

CRESCO involvement only related to the preparation of a financial model based on external consultant inputs. CRESCO did not validate any of these assumptions to source and thus relied on the inputs. CRESCO does not accept responsibility for the final outputs of the model based on the external inputs provided.

Source of assumptions:

Information has been provided by the following people, per responsible areas:

Mario Patel **WorleyParsons**	•Timing Assumptions
Madhavendra Bhatia **WorleyParsons**	•Capex •Opex
Gauthier van Marcke **Galway Group**	•Opex •Production •LNG Price

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Disclaimer:

This document is based on the assumptions provided by project stakeholders. CRESCO has reproduced the assumptions from the excel based financial model. CRESCO requires the stakeholder confirmation and sign off of the input assumptions for accuracy and consistency.

TIMING ASSUMPTIONS

	Item	Input (Date yyyy/mm/dd)	Comment / Rationale	Source
1.1	Financial Close	2016/09/01	In line with Cons Start Date	CRESCO assumption
1.2	Construction Start Date	2016/09/01	Considering timing of key milestones; EIA, FEED, etc. Received on 2014/03/13	Mario Patel (WorleyParsons) File name: Mauritius LNG Implementation Plan Draft Option 1.pdf
1.3	Scheduled COD	2018/07/31	Based on experience. 23 Months construction period	Mario Patel (WorleyParsons) File name: Mauritius LNG Implementation Plan Draft Option 1.pdf
1.4	End of operations	2043/07/31	25 years of Operations	Basis of design
1.5	Index Base Date for inflation indices	2016/09/01	Financial close date as Base date	CRESCO assumption

CAPEX INPUTS

	Item	Input (Amount '000)	Comment / Rationale	Source
2.1	Jetty Structure	USD 52 421	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.2	Jetty Topsides Equipment	USD 6 900	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.3	Jetty Topsides Construction	USD 23 184	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.4	Export Gas Spipeline	USD 14 421	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.5	ORF Equipment	USD 9 000	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx

	Item	Input (Amount '000)	Comment / Rationale	Source
2.6	ORF Construction	USD 3 001	At +-50% accuracy excluding contingency. Received on 2014/03/172014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.7	ORF Misc	USD 22 621	At +-50% accuracy excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.8	Feasibility Study - LNG Terminal	USD 989	At 0.75% of LNG Import Facility, based on experience. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.9	FEED - LNG Terminal	USD 14 289	At 13% of LNG Import Facility less Implementation cost, based on experience. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.10	Implementation - LNG	USD 2 935	Based on experience. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx

	Item	Input (Amount '000)	Comment / Rationale	Source
2.11	Contingency	USD 29 365	At 20% of all costs above. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
	TOTAL CONSTRUCTION COSTS	**USD 179 713**		

OPEX INPUTS: FIXED & VARIABLE

	Item	Input (Amount '000)	Comment / Rationale	Source
3.1	FSRU Charter Cost	USD 45 625	FSRU Charter Cost of USD125k per day (CAPEX Component Only) No Escalation- Annual Cost: $45.625 Million (15 year charter)	Gauthier van Marcke File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)
3.2	Crew cost at Jetty & ORF	USD 600	USD 0.3m for the Jetty crew and USD 0.3m for the ORF crew	Madhavendra Bhatia File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)

	Item	Input (Amount '000)	Comment / Rationale	Source
3.3	Maintenance & Spares	USD 1 810	Composed of the following: • Jetty top side & Moorings = Based on 3% of Total Equipment cost • ORF = Based on 3% of Supply cost • Sub-sea Pipeline = Based on 1% of Supply cost	Madhavendra Bhatia File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)
3.4	Own Consumption (FSRU Fuel)	Op Yr 1= USD 44 Op Yr 5= USD 66 Op Yr 10= USD 121 Op Yr 15= USD 195 Op Yr 20= USD 222 Op Yr 25= [USD 260]	1.5% of LNG throughput at [DES] LNG Price. Assuming open loop mode on FSRU. Fuel retainage is a pass through to Charterer under Time Charter Party Agreement. 1.5% fuel usage is a guaranteed fuel rate for open loop, but at minimum send-out of usually 100 MMCFD.	Gauthier van Marcke File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)

	Item	Input (Amount '000)	Comment / Rationale	Source
3.5	Crew cost at FSRU	USD 8 030	USD22k per day	Gauthier van Marcke File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)
3.6	Project Management + Insurance	USD 1 797	1% of CAPEX	Madhavendra Bhatia File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)
3.7	Electricity (FSRU, Jetty, ORF)	USD 300	Electricity unit cost 0.22 USD/KWH	Madhavendra Bhatia File name: Galway Comments to OPEX CAPEX Summary_CC_MB_080314.xlsx (Received on 2014/03/11)

PRODUCTION INPUTS

	Item	Input Per Unit	Unit	Source
4.1	Total Capacity	1	MTPA	Gauthier van Marcke & Madhavendra Bhatia (Basis of design)

	Item	Input Per Unit	Unit	Source
4.2	Required LNG • Base case 50% load factor	Base case: Op Yr 1=0.061 Op Yr 5=0.154 Op Yr 10=0.226 Op Yr 15=0.302 Op Yr 20=0.301 Op Yr 25=0.302	MTPA	Original inputs: Gauthier van Marcke Adjustment for load factors: CRESCO Demand is from New 100MW plant, other plants after conversion and other industries mainly transport. File name: 20140716 LNG requirement projections Galway 03122013 (2)fv.xlsx
4.3	Ramp Up	100	%	CRESCO assumption
4.4	Planned Shutdowns	1.43	# Weeks p.a	Gauthier van Marcke (Not impacting Availability as redundancy is built in: "10 days is not unusual and therefore I would use that... For large scale terminals, it is not unusual to have built in redundancy to operate 100% of the time (barring extraordinary circumstances).
4.5	Utilisation	100	%	Gauthier van Marcke
4.6	Availability	100	%	Gauthier van Marcke

FUNDING ASSUMPTIONS

	Item	Input Per Unit	Unit	Source / Rationale

	Item	Input Per Unit	Unit	Source / Rationale
5.1	Debt:Equity	60:40	Ratio	CRESCO assumption based on experience
5.2	Debt tenure	10	Years	CRESCO assumption based on experience
5.3	Upfront fees	1.5	%	CRESCO assumption based on experience
5.4	Commitment fees	0.6	%	CRESCO assumption based on experience
5.5	Agency fees	During Construction=55 During operations=45	UDS'000	CRESCO assumption based on experience
5.6	DSCR (Debt Service Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.7	ICR (Interest Cover Ratio)	1.10	Ratio	CRESCO assumption based on experience
5.8	PLCR (Project Life Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.9	LLCR (Loan Life Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.10	Method of repayment	Annuity		CRESCO assumption based on experience

	Item	Input Per Unit	Unit	Source / Rationale
5.11	All in interest	7.98	%	CRESCO assumption based on experience
5.12	Debt Service Reserve Account	6 (pre funded at the start of operations)	Months	CRESCO assumption based on experience

MACRO-ECONOMIC ASSUMPTIONS

	Item	Input Per Unit	Unit	Comment / Rationale	Source
6.1	Inflation (CPI)	3.5	%	For Op year 1 – 25	Statistics Mauritius website Q4 2013 (MoFED)
6.2	Prime Rate	4.15	%	For Op year 1 – 25	Mauritian prime (State Bank of Mauritius - website)
6.3	Interest on Positive Balance (Applied)	0.65	%	For Op year 1 – 25	Prime -3.5% Based on State Bank of Mauritius (website)
6.4	Forex: • USD:MUR • USD:EUR	• 0.03 • 1.4	• USD:MUR • USD:EUR	For Op year 1 – 25	Current rates as per Bloomberg website. CRESCO assumed constant over time.
6.5	Brent Crude: Forward curve	• 2018: 98.2 • 2022: 109.37 • 2027: 138.99 • 2042: 212.14	• $/Barrel	• US DOE curve	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12

	Item	Input Per Unit	Unit	Comment / Rationale	Source
6.6	Brent Crude: Henry Hub[1]	• 2018:5.27 • 2022:5.64 • 2027:7 • 2042:8.91	• $/Mmbtu	• US DOE curve	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12
6.7	LNG Pricing[1]	High oil case: • Margin = 14.5% • Difference =$-0.5 Low oil case: • Margin = 11.8% • Difference =$-0.9 Mid oil case: • Margin = 13% • Difference =$0.6 Henry Hub pricing: • Margin = 125% • Difference =$6	• $/Mmbtu	For the High, Low and Mid cases the LNG price is derived from the brent crude oil price as follows: (Brent Crude price*Margin) + Difference. For the Hunry Hub case, LNG price is derived as: (Henry Hub price of oil*Margin) + Difference.	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12

[1] See Appendix below.

Appendix A: Brent Crude price and LNG

LNG Price

Brent Crude		2016	2017	2018	2019	2020	2021	2022
Forward curve	$/Barrel	101.95	99.57	98.20	101.54	105.21	109.37	109.37
Henry Hub	$/Mmbtu	4.41	4.76	5.27	5.19	4.96	5.37	5.64

				Op Yr 0	Op Yr 0	Op Yr 1	Op Yr 2	Op Yr 3	Op Yr 4	Op Yr 5
LNG		Margin	Difference	2016	2017	2018	2019	2020	2021	2022
High Oil case	$/Mmbtu	14.5%	$ -0.50	14.28	13.94	13.74	14.22	14.76	15.36	15.36
Low Oil case	$/Mmbtu	11.8%	$ -0.90	11.13	10.85	10.69	11.08	11.51	12.01	12.01
Mid Oil case	$/Mmbtu	13.0%	$ 0.60	13.85	13.54	13.37	13.80	14.28	14.82	14.82
Henry Hub Linked case	$/Mmbtu	125.0%	$ 6.00	11.51	11.95	12.59	12.49	12.20	12.71	13.05
Applied				13.85	13.54	13.37	13.80	14.28	14.82	14.82

Project	Mauritius New 100MW Power Plant
Document Purpose	The purpose of this document is to list the key project assumptions: - Technical - Financial - Market - Production In a non excel based format for the client / technical advisor / market advisor confirmation and sign off
Key CRESCO Contact	Francois Viljoen
Excel file	20140717.100MW.LNG.PowerPlant.xlsm
Version	1
Date	18 Jul. 14

CRESCO Scope:

CRESCO involvement only related to the preparation of a financial model based on external consultant inputs. CRESCO did not validate any of these assumptions to source and thus relied on the inputs. CRESCO does not accept responsibility for the final outputs of the model based on the external inputs provided.

Source of assumptions:

Information has been provided by the following people, per responsible areas:

David Stauffer Mario Patel **WorleyParsons**	•Timing Assumptions
Madhavendra Bhatia David Stauffer **WorleyParsons**	•Capex
David Stauffer **WorleyParsons**	•Opex •Production

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Disclaimer:

This document is based on the assumptions provided by project stakeholders. CRESCO has reproduced the assumptions from the excel based financial model. CRESCO requires the stakeholder confirmation and sign off of the input assumptions for accuracy and consistency.

TIMING ASSUMPTIONS

	Item	Input (Date yyyy/mm/dd)	Comment / Rationale	Source
1.1	Financial Close	2017/01/01	In line with Cons Start Date	CRESCO assumption
1.2	Construction Start Date	2017/01/01	Considering timing of key milestones; EIA, FEED, etc. Received on 2014/03/13	Mario Patel (WorleyParsons) File name: Mauritius LNG Implementation Plan Draft Option 1.pdf
1.3	Scheduled COD	2018/10/01	Based on experience and after completion of Terminal. 21 Months construction period	Mario Patel (WorleyParsons) File name: Mauritius LNG Implementation Plan Draft Option 1.pdf
1.4	End of operations	2043/09/30	25 years of Operations	Basis of design, David Stauffer
1.5	Index Base Date for inflation indices	2017/01/01	Financial close date as Base date	CRESCO assumption

CAPEX INPUTS

	Item	Input (Amount '000)	Comment / Rationale	Source
2.1	Total plant EPC	USD 126 990	Specialised equipment, labour and materials with contingencies at 4% for equipment, 15% for labour and 25% for materials. At +-50% accuracy. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.2	Feasibility Study - New 100MW PS	USD 266	At 21% of Total EPC cost, excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.3	FEED - New 100MW PS	USD 1 578	At 1.25% of Total EPC cost, excluding contingency. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
2.4	Implementation - New 100MW PS	USD 1 593	At +-50% accuracy excluding contingency, based on experience. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx

	Item	Input (Amount '000)	Comment / Rationale	Source
2.5	Contingency	USD 26 086	At 20% of all costs above. Received on 2014/03/17	Madhavendra Bhatia File name: Capex Summary and Cost Flows - 17 March 2014 Rev03.xlsx
	TOTAL CONSTRUCTION COSTS	**USD 156 523**		

OPEX INPUTS: FIXED & VARIABLE

	Item	Input (Amount '000) or Units	Comment / Rationale	Source
3.1	O&MC: Operations and Maintenance Contract	USD 1 959	[Rationale] No inflation.	David Stauffer File name: 2014-03-03 Financial Model Input- 100 MW Power Plant - RevB.docx (Received 2014/03/10)
3.2	LNG import cost (SPA)[1]	In US$/Mmbtu • 2018:5.27 • 2022:5.64 • 2027:7 • 2042:8.91	US DOE curve, see macro-economic assumptions. No inflation	Gauthier van Marcke (US DOE EIA - AEO 2014) Source name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx (Received 2014/03/12)

	Item	Input (Amount '000) or Units	Comment / Rationale	Source
3.3	Terminal usage fees (TUA)[2]	For Ops yr 1 in US$/Mmbtu: • 50% load factor = 29.31 • 35% load factor = 41 • 65% load factor= 12.52 • 85% load factor = 10.77	The Terminal model determines a tariff based on amounts of LNG required by the industry. The terminal usage fees decrease with increasing demand.	Mauritius LNG Terminal model. Terminal Model results based on 4 LNG demand scenarios. File name: 20140716.LNG.Terminal.xlsm
3.4	Water Requirement	2.8 US$/m3	Based on technology specifications	David Stauffer File name: 282570-MauritiusLNG-Pre-FS Rpt R0 (draft) - RDG - 2014-02-18 - No Google Earth.docx (Received 2014/02/23)
3.5	O&M (Maintenance, chemicals & consumables)	4.5 US$/MWh	Based on technology specifications	David Stauffer File name: 282570-MauritiusLNG-Pre-FS Rpt R0 (draft) - RDG - 2014-02-18 - No Google Earth.docx (Received 2014/02/23)

[1]See Appendix A below
[2]See Appendix B below

PRODUCTION INPUTS

	Item	Input Per Unit	Unit	Source / Rationale
4.1	Total Capacity	97.93	MW	David Stauffer & Madhavendra Bhatia (Basis of design)
4.2	Ramp Up	100	%	David Stauffer NA. Only single Phase project. Full power after construction/commissioning
4.3	Loss Factors: • Network losses • House load	0	%	David Stauffer 8%-10% network losses not paid for by Plant. House load already accounted for by engineers, production input provided net generation losses.
4.4	Planned Outages	0.07	# Weeks p.a	David Stauffer As per LM6000 Typical Scheduled Maintenance Actions, Intervals and Duration.
		0.57	# Weeks every 8 years	
4.5	Forced Outages	0.5	%	David Stauffer Aero engines have high reliability.

	Item	Input Per Unit	Unit	Source / Rationale
4.6	Utilisation	50	%	David Stauffer The new plant will be dispatched and likely to be a base loaded unit. In the economic analysis, we assumed 50% as the default.
4.7	Power Output Degredation	0 to -2.8	%	David Stauffer At this stage of the project, we suggest that we ignore the saw tooth nature of the curve and just assume a linear degradation with operation hours. (0% degradation at 0 hours, full degradation at 50,000 hours. Linear interpolation in between.)
4.8	Heat Rate Degredation	0 to +1.4	%	David Stauffer At this stage of the project, we suggest that we ignore the saw tooth nature of the curve and just assume a linear degradation with operation hours. (0% degradation at 0 hours, full degradation at 50,000 hours. Linear interpolation in between.)
4.9	Availability	96	%	David Stauffer [Rationale]

FUNDING ASSUMPTIONS

	Item	Input Per Unit	Unit	Source / Rationale
5.1	Debt:Equity	60:40	Ratio	CRESCO assumption based on experience
5.2	Debt tenure	10	Years	CRESCO assumption based on experience
5.3	Upfront fees	1.5	%	CRESCO assumption based on experience
5.4	Commitment fees	0.6	%	CRESCO assumption based on experience
5.5	Agency fees	During Construction=55 During operations=45	UDS’000	CRESCO assumption based on experience
5.6	DSCR (Debt Service Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.7	ICR (Interest Cover Ratio)	1.10	Ratio	CRESCO assumption based on experience
5.8	PLCR (Project Life Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.9	LLCR (Loan Life Cover Ratio)	1.30	Ratio	CRESCO assumption based on experience
5.10	Method of repayment	Annuity		CRESCO assumption based on

	Item	Input Per Unit	Unit	Source / Rationale
				experience
5.11	All in interest	7.98	%	CRESCO assumption based on experience
5.12	Debt Service Reserve Account	6 (pre funded at the start of operations)	Months	CRESCO assumption based on experience

MACRO-ECONOMIC ASSUMPTIONS

	Item	Input Per Unit	Unit	Comment / Rationale	Source
6.1	Inflation (CPI)	3.5	%	For Op year 1 – 25	Statistics Mauritius website Q4 2013 (MoFED)
6.2	Prime Rate	4.15	%	For Op year 1 – 25	Mauritian prime (State Bank of Mauritius - website)
6.3	Interest on Positive Balance (Applied)	0.65	%	For Op year 1 – 25	Prime -3.5% Based on State Bank of Mauritius (website)
6.4	Forex: • USD:MUR • USD:EUR	• 0.03 • 1.4	• USD:MUR • USD:EUR	For Op year 1 – 25	Current rates as per Bloomberg website. CRESCO assumed constant over time.
6.5	Brent Crude: Forward curve	• 2018: 98.2 • 2022: 109.37 • 2027: 138.99 • 2042: 212.14	• $/Barrel	• US DOE curve	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12

	Item	Input Per Unit	Unit	Comment / Rationale	Source
6.6	Brent Crude: Henry Hub[1]	• 2018:5.27 • 2022:5.64 • 2027:7 • 2042:8.91	• $/Mmbtu	• US DOE curve	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12
6.7	LNG Pricing[1]	High oil case: • Margin = 14.5% • Difference =$-0.5 Low oil case: • Margin = 11.8% • Difference =$-0.9 Mid oil case: • Margin = 13% • Difference =$0.6 Henry Hub pricing: • Margin = 125% • Difference =$6	• $/Mmbtu	For the High, Low and Mid cases the LNG price is derived from the brent crude oil price as follows: (Brent Crude price*Margin) + Difference. For the Hunry Hub case, LNG price is derived as: (Henry Hub price of oil*Margin) + Difference.	Gauthier van Marcke (US DOE EIA - AEO 2014) File name: 20140312 LNG requirement projections Galway 03122013 (2).xlsx, received 2014/03/12

[1] See Appendix below.

Appendix A: Brent Crude price and LNG

LNG Price

Brent Crude			2016	2017	2018	2019	2020	2021	2022
Forward curve	$/Barrel		101.95	99.57	98.20	101.54	105.21	109.37	109.37
Henry Hub	$/Mmbtu		4.41	4.76	5.27	5.19	4.96	5.37	5.64

				Op Yr 0	Op Yr 0	Op Yr 1	Op Yr 2	Op Yr 3	Op Yr 4	Op Yr 5
LNG		Margin	Difference	2016	2017	2018	2019	2020	2021	2022
High Oil case	$/Mmbtu	14.5%	$ -0.50	14.28	13.94	13.74	14.22	14.76	15.36	15.36
Low Oil case	$/Mmbtu	11.8%	$ -0.90	11.13	10.85	10.69	11.08	11.51	12.01	12.01
Mid Oil case	$/Mmbtu	13.0%	$ 0.60	13.85	13.54	13.37	13.80	14.28	14.82	14.82
Henry Hub Linked case	$/Mmbtu	125.0%	$ 6.00	11.51	11.95	12.59	12.49	12.20	12.71	13.05
Applied				13.85	13.54	13.37	13.80	14.28	14.82	14.82

Appendix B: Brent Crude price and LNG

		Op Yr 0	Op Yr 0	Op Yr 1	Op Yr 2	Op Yr 3	Op Yr 4	Op Yr 5	Op Yr 6	Op Yr 7	Op Yr 8	Op Yr 9	Op Yr 10
Terminal Fee		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50% load factor	$/Mmbtu	-	-	29.31	14.51	14.40	14.32	13.45	12.73	12.20	11.70	11.29	10.88
35% load factor	$/Mmbtu	-	-	41.00	16.80	16.55	16.34	15.15	14.19	13.48	12.81	12.28	11.77
65% load factor	$/Mmbtu	-	-	12.52	6.57	6.48	6.36	6.04	5.77	5.55	5.36	5.18	4.99
85% load factor	$/Mmbtu	-	-	10.77	6.07	6.01	5.93	5.66	5.44	5.25	5.07	4.91	4.77
Applied		-	-	29.31	14.51	14.40	14.32	13.45	12.73	12.20	11.70	11.29	10.88