Report Overview

Feasibility Study for the Adoption of Liquefied Natural Gas (LNG)

Prepared for

Ministry of Energy and Public Utilities, Republic of Mauritius

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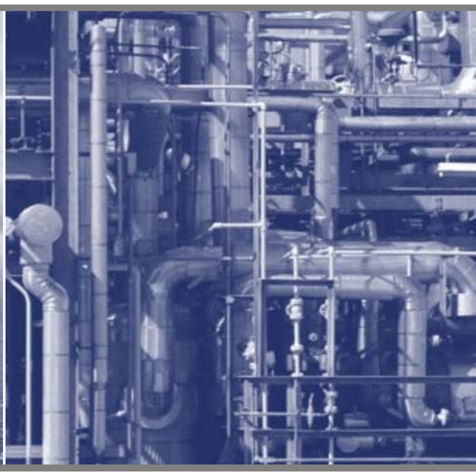


Section 10 REPORT OVERVIEW

This report overview relates to the findings of the Feasibility Study for the Adoption of Liquified Natural Gas (LNG) prepared by Poten & Partners in 2018 (the Report). It summarises the study and key conclusions and recommendations are underlined in the report.

10.1 ASSESSMENT OF LNG DEMAND IN MAURITIUS

The Report assessed the demand for LNG in Mauritius across five broad market segments: power generation, industrial/commercial/residential, transportation, LNG bunkering for ships and re-exports to regional countries.

10.1.1 LNG Bunkering

A detailed assessment of the LNG bunkering potential for all types of ships calling at Port Louis was carried out and showed limited potential for LNG bunker sales out of Mauritius. Most of the ships calling regularly in Port Louis are smaller ships, such as feeder containerships, fishing boats, shuttle LPG tankers or passenger cargo ships with relatively low annual fuel requirements. Larger ships such as tankers and bulkers operate on a tramping basis i.e. not making regular calls at Port Louis. Similarly, Neo-Panamax containerships or cruise liners only return to Port Louis infrequently. Shipping companies with activities in and out of Mauritius tend to operate second generation ships (older ships) in the Indian Ocean, whereas LNG-fuelled ships are almost exclusively recent newbuilds and conversion of existing vessels tends to be impractical. In view of this assessment, base case LNG demand does not include any LNG bunker sales in Mauritius.

However, the Report recognised that future growth of LNG bunker demand is difficult to forecast, given the uncertainties surrounding this nascent market. A high case was developed on the basis that some ships seeking LNG would pass through Port Louis. The high case assessment adopted the assumption that LNG bunkers in Mauritius could grow faster than overall local bunker demand which is a mature market. On the other hand, LNG bunker demand in Mauritius should not grow as fast as the demand in the global market generally, due to the specific limitations highlighted in the LNG bunkering base case e.g. lack of regular calls by large ships. The high case has been estimated as the average of the demand growth rate for bunkers of all types in Mauritius and the global demand for LNG bunkers. Based on this approach, the high case demand for LNG bunkering would be 63 thousand tonnes/year (kt/y) in 2023, increasing to 280 kt/y in 2040.

<u>If Mauritius chooses to go down the LNG path the government should pursue a process of seeking proposals from LNG bunkering industry participants to establish an LNG bunkering business i.e. let the industry participants decide if they believe there is a viable business.</u>

10.1.2 LNG Re-exports

The Report reviewed the potential for regional LNG re-exports. The assessment was carried out using public domain assessments of energy use in the region and some market intelligence on the Seychelles. Attempts were made to investigate the LNG potential in Reunion in greater depth, because of its proximity to Mauritius, but there was little interest in LNG and no meetings could be arranged with Reunion.

The assessment showed there is "potential" LNG demand across the region e.g. Madagascar, Comoros, Reunion and the Seychelles. However, unless there is a strong drive from the governments of these countries to pursue LNG the international relations and commercial complexities of re-exporting LNG will be challenging.

Nevertheless, the Report developed a case study looking at LNG re-exports of 100 kt/y to the Seychelles to provide an indicator of the feasibility of re-exports. The case study considered the logistics chain between Mauritius and the Seychelles i.e. transportation, using both small scale ships and ISO containers, and a small-scale LNG terminal in the Seychelles. The case study found that the ex-terminal cost of LNG would be higher than heavy fuel oil (HFO) but less than the price of diesel. On this basis the incentive for the Seychelles to switch from HFO to LNG would not be great. However, the decision would not be based on price alone and if social and environmental factors are included in the equation, the Seychelles may choose to switch to LNG. Based on the case study results and the potential challenges in achieving international co-operation on LNG, the Report does not include any LNG re-exports in the base case for LNG demand but includes 100 kt/y of re-exports to the Seychelles in the high case LNG demand.

The proximity of the other counties in the region to Mozambique also poses a threat to regional re-exports from Mauritius. If the onshore Mozambique LNG project commences operations, estimated to be after 2025, with small scale LNG facilities included, the project may consider the direct supply of LNG to nearby countries and thereby pose a competitive threat to potential supplies from a Mauritius LNG hub.

<u>If Mauritius chooses to go down the LNG path the government should pursue a process of dialogue with regional countries to promote and test the potential for re-exports of LNG.</u> While LNG may cost more than alternative fuels a switch to LNG could still occur, justified on environmental grounds.

10.1.3 Power Generation Demand

The Report reviewed the potential for use in power generation in Mauritius and found power generation demand is expected to be the main user of LNG in Mauritius. Power generation is expected to represent 99% of demand initially, decreasing to 86% of demand in 2040.

The Report reviewed the existing power system in Mauritius including the Central Electricity Board (CEB) heavy fuel oil (HFO) power plants and the coal/bagasse Independent Power Producers (IPPs). All the CEB thermal power plants were visited, as well as two of the IPP power plants to discuss the technology and operation with the respective plant operators. An assessment was made on the potential to convert the CEB and IPP power plants to run on gas. The assessment concluded that the Saint Louis and Fort Victoria power plants were good candidates for conversion to gas but the CEB Fort George and Nicolay power plants and the IPPs were not.

The Report also considered future electricity demand in Mauritius and power generation expansion plans. Power generation expansion plans considered the plants currently under consideration i.e. the proposed CEB Combined Cycle Gas Turbine (CCGT) power plant at Fort George and a new Alteo IPP. Estimates were made for future renewable power plants i.e. solar and wind. The remaining future need for power was assumed to be met by further CCGTs being installed as necessary to ensure an adequate supply margin as electricity demand continues to grow.

Power generation modelling was carried out for several different operating scenarios to estimate the demand for LNG. As a fundamental premise for the Report it was assumed that LNG is intended to displace more polluting fossil fuels i.e. HFO and coal due to environmental advantages such as lower emissions of carbon dioxide (CO_2) and other pollutants. Therefore, the power generation base case assumes that generation from coal will be minimised consistent with the CEB’s Power Purchase Agreements (PPAs) with the IPPs and PPA renewals would be for bagasse fueled power only. In addition, the Saint Louis and Fort Victoria power plants would be converted to use regasified LNG.

A low case for power generation with LNG was developed on the basis that coal burning continues on a “business as usual basis” i.e. maximizing coal burning in the IPPs. A high case was built based on an early phase-out of all coal use by renegotiating the PPAs and the high demand case for electricity production. The LNG requirements for the power generation base and low cases are shown in the table below.

Table 10-1 LNG Volumes for Power Generation (kt/y)

Case	2023	2025	2030	2035	2040
Base	240	270	340	390	440
Low	150	150	260	330	410

10.1.4 Industrial/Commercial/Residential Demand

The Report reviewed potential LNG demand in the industrial, commercial and residential sectors and found that demand is expected to be small.

The base volume for the industrial segment of the market is expected to be limited. Overall energy use in the industrial sector has been, and is expected to continue to decline, and the larger industrial energy consumers are price sensitive e.g. the textile industry. In the industrial sector, LNG is expected to be more expensive than HFO on a delivered basis. In this case, the base volume assumption in the industrial segment, is estimated to be 10% of industrial oil product consumption (heavy fuel oil and gasoil). Based on this approach, the base case demand for the industrial use of LNG would be 0.4 kt/y in 2023, increasing to 4 kt/y in 2040.

The demand for LNG in the commercial and residential sectors is expected to be negligible. In the commercial sector LNG would be seeking to replace LPG e.g. in resorts and hotels. In this sector the cost of replacing the existing LPG infrastructure with LNG infrastructure would be expensive and the environmental benefits of switching from LPG to LNG are much less than in switching from HFO or coal to LNG. In the domestic sector, LNG could potentially replace LPG used in homes. To achieve this would require a major investment in gas distribution infrastructure. Using distribution tariff information from other locations indicates the cost of domestic gas from LNG would be significantly more expensive than LPG (which is currently subsidised).

10.1.5 Transportation Demand

In the transportation sector, LNG is expected to achieve some penetration, albeit with slow take up. In the light vehicle sub-sector, LNG as Compressed Natural Gas (CNG) is expected to be lower priced than gasoline, however, there are several barriers that will hold vehicles owners back from choosing CNG vehicles e.g. reticence to adopt new technologies, higher vehicle costs, a limited choice of CNG models from manufacturers and competition from hybrid/electric vehicles.

In the heavy-duty vehicle sub-sector, LNG and CNG should be lower priced than diesel and be environmentally cleaner. In this sector LNG/CNG use should be less difficult to implement than for light vehicles, particularly for fleets such as buses and waste collection trucks where refueling can take place at a central depot. The Report estimates 5% penetration of CNG into light vehicles and a 10% penetration of CNG/LNG into the heavy vehicle fleet. Based on this approach, the base case demand for the use of LNG in transportation would be 1.7 kt/y in 2023, increasing to 55 kt/y in 2040.

10.1.6 LNG Demand Summary

The Report developed a base case volume as well as a low case and a high case for LNG demand in Mauritius. The base case volume was built up using the base cases for power generation, industrial and transportation and is shown in the table below.

Table 10-2 LNG Import Base Case Volume (kt/y)

Sector	2023	2025	2030	2035	2040
Power	240	270	340	390	440
Industrial	0.2	0.4	4.0	4.6	4.8
Commercial/Domestic	0	0	0	0	0
Transportation	1.7	5.3	27.9	41.7	55.4
LNG Bunkering	0	0	0	0	0
Re-exports	0	0	0	0	0
Total	242	276	372	436	500

The low case for LNG demand adopted the low case power generation demand. The high case LNG demand added LNG bunkering and LNG re-exports to the base case. The three cases are summarised in the table below.

Table 10-3 LNG Import Volume Scenarios (kt/y)

Sector	2023	2025	2030	2035	2040
Low Case	152	156	292	356	470
Base Case	242	276	372	436	500
High Case	365	473	662	776	890

10.1.7 LNG Terminal Sizing

The LNG demand analysis was used as a basis to size LNG terminal concepts. Review of the base case volume indicates an initial terminal capacity of 300 kt/y would be appropriate. This level of throughput would be reached relatively quickly (around 2026) so any initial under utilisation of the terminal would be small. Throughput grows steadily to reach 500 kt/y in 2040. For terminals with onshore regasification, throughput could be readily increased to satisfy 500 kt/y with the inclusion of an additional module in the regasification plant. This would be a cost-effective expansion required sometime after 2030. Other elements of the terminal e.g. berth and storage would not need expansion.

In the low case, initial throughput would be around 150 kt/y so there would be significant under utilisation of the terminal until near 2030 but thereafter expansion would also become necessary after 2035.

In the high case, initial throughput would be around 360 kt/y which exceeds the proposed 300 kt/y starting size for the terminal. However, most of the growth in the high case (above the base case) is associated with LNG bunkering and re-exports which involves the supply of LNG not regasified LNG, hence expansion of the regasification facility in the high case would be the same as in the base case.

The base case LNG demand supports the development of an LNG import terminal in Mauritius with and initial throughput of 300 kt/y that would be expandable to 500 kt/y.

10.2 SOURCES OF LNG AND SHIPPING

The Report addressed sources of LNG for Mauritius and covered four areas: the global LNG market, LNG supply sources for Mauritius, LNG pricing and LNG shipping.

10.2.1 The Global LNG Market

10.2.1.1 Global LNG demand

Global LNG demand has grown as the number of importing countries, largely to meet power generation needs, increased from 12 in 2000 to 39 countries in 2017. A combination of growing environmental and regulatory pressures, new LNG production capacity and competitive pricing are projected to drive a strong expansion of LNG imports, from around 290 MMt in 2017 to over 450 MMt/y by 2040.

10.2.1.2 Global LNG supply

LNG was produced and exported from 18 countries in 2017. LNG exports more than doubled from 114 MMt in 2000 to 290 MMt in 2017, driven in large part by production growth in Qatar and Australia.

Forecasts show LNG production surpassing 350 MMt/y by 2020 and 450 MMt/y by 2040. While Qatar led the supply expansion from 2008 to 2011, Australia is leading the current LNG export expansion. The growth in Australia will be followed by a large expansion in North American projects through to 2020 and then eventually East African projects post 2020.

10.2.1.3 Supply/demand balance

In 2018, the LNG market was absorbing a wave of LNG supply from projects that were committed earlier in the decade. The LNG market has been struggling to absorb this supply wave, and as a result, LNG suppliers have found it difficult to sell LNG and LNG prices have trended downward. However, this situation, along with low oil prices in the 2015 to 2018 period, has seen commitments to new LNG projects become relatively rare. This will lead to a tightening of supply over the next few years as demand continues to grow while new LNG supply is slow to emerge. Post 2020, the market is expected to tighten putting upward pressure on pricing.

The initial Mauritius LNG demand of 300 kt/y represents less than 0.1% of global LNG production in what is an increasingly flexible (commoditised) market. If Mauritius seeks to purchase LNG around 2019 the market should be favourable with more than enough supply available and prices near the bottom of the market cycle.

10.2.2 LNG Supply Sources for Mauritius

From an LNG supply viewpoint, Mauritius will be looking for potential LNG supplies to satisfy its demand starting at around 240 kt/y in 2023 and growing to 500 kt/y by 2040. The potential LNG suppliers for the Mauritius project will consider the size of the import terminal to be small which will complicate technical/commercial supply discussions. LNG supply for Mauritius could come direct from LNG projects or through the secondary LNG market via LNG aggregators and traders.

10.2.2.1 LNG supply projects

There will be opportunities for Mauritius to purchase LNG directly from liquefaction projects, although this may not be the easiest form of supply for the project to secure. The two nearest large supply sources would be north-west Australia (e.g. the North West Shelf, Pluto, Gorgon and Wheatstone projects) and the Middle East (e.g. Qatar). However, none of these projects currently have the facilities to load small sized LNG ships and may not be willing to do so in future. LNG supply direct from these projects would most likely need to be on conventional sized ships.

The Bontang LNG project in Indonesia and the Bintulu project in Malaysia both regularly load small sized ships, but they are at a slightly longer distance than the Middle East or north-west Australia. These projects may be able to supply volumes to Mauritius on small and medium sized ships. Bontang (Pertamina) is an older project with currently declining sales volumes but may still have some capacity available. Bintulu (Malaysia LNG) is a project that has recently expanded and is facing potential long-term contract expirations over the next few years and may therefore be more willing to consider supply to Mauritius.

Closer to Mauritius, the Coral FLNG project is under development in Mozambique and is expected to be operational around 2023. While the project offers short shipping distances, all volumes from the project have already been sold to BP and it is unlikely that the project would be willing to load small ships due to the operational challenges with loading small ships at an FLNG project. Future, larger land-based projects in Mozambique may include facilities to load small/medium ships but first LNG from these projects is currently predicted to be after 2025. A project on this timeline is too late to provide LNG to Mauritius in 2023 but may become an important supply opportunity in the longer term.

10.2.2.2 LNG aggregators and traders

Changing patterns in LNG trade over the last decade have seen the emergence of aggregators in the LNG industry i.e. companies that have a portfolio of supply contracts and market outlets, and the shipping capacity to connect the two. The key aggregators that have been operating in the industry include: Shell, Total, BP and Naturgy. Each of these aggregators has access to multiple, large sources of supply across both Asia Pacific and the Atlantic Basin and have the capability to provide all volumes required for Mauritius.

In addition to aggregators, the main commodity trading houses also have an active presence in the LNG market e.g. traders such as Vitol, Trafigura and Gunvor. These types of trading companies are also able to take on mid- to long-term commitments to supply volumes of LNG. Trading houses tend to be more aggressive when taking on short- to mid-term risk including credit risk.

In today’s LNG market it is likely that LNG for Mauritius will come from this aggregator/trader group, some of whom may be attracted to Mauritius through a combined LNG supply/terminal development deal.

10.2.3 LNG Pricing

10.2.3.1 Global LNG Pricing

The gas industry has developed on a regional, rather than a global basis. As a result, gas and LNG do not currently have a single international benchmark price.

There are three key regional price mechanisms for gas and LNG are as follows:

- Asia – gas is mostly priced through indexation to crude oil but some indexation to Henry Hub and the Japan Korea Marker price have emerged recently
- North America – pricing is driven by gas supply and demand fundamentals as demonstrated by gas hub pricing e.g. Henry Hub (HH) in the US
- Europe – pricing has traditionally been based on indexation to crude/oil products but increasingly it is being based on supply and demand fundamentals as demonstrated by gas hub pricing e.g. the National Balancing Point (NBP) in the UK and the Title Transfer Facility (TTF) in the Netherlands.

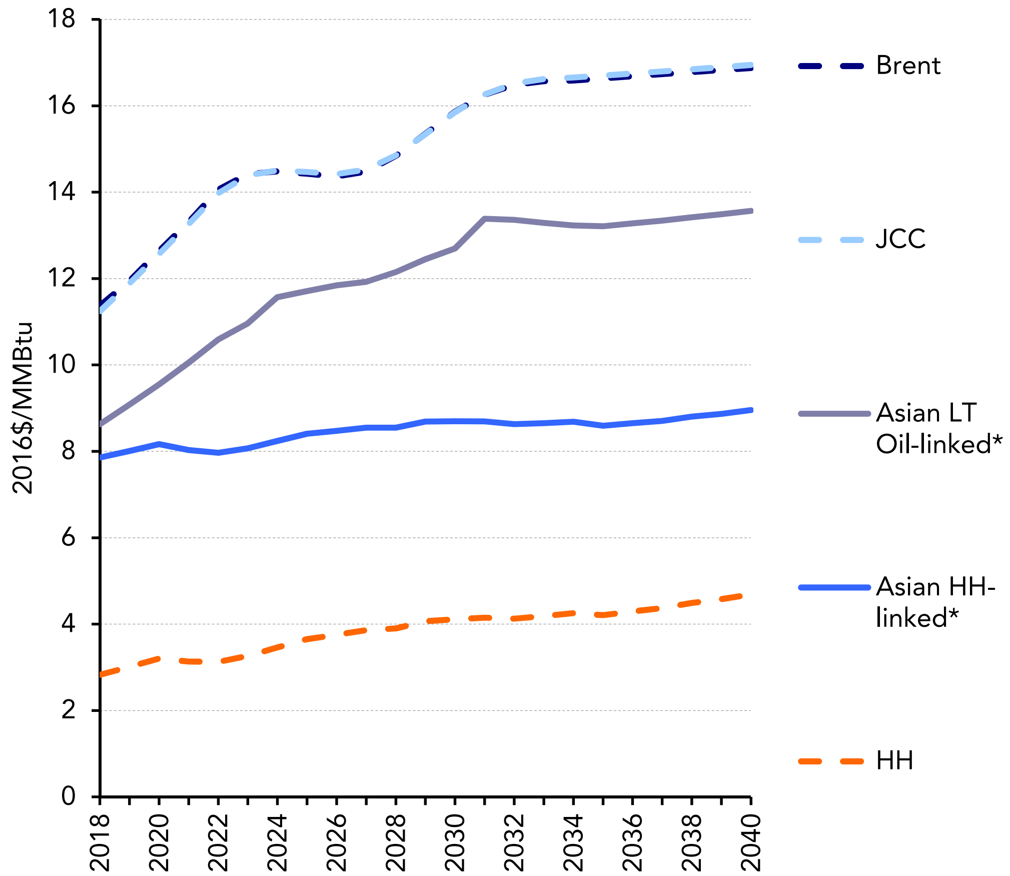
Asian LNG prices (including the Indian Ocean) are expected to continue to be mostly derived from oil indexation. However, the large ramp up of North American LNG exports with pricing based on US gas market prices (HH indexation) is bringing a new dynamic to global LNG pricing. It is also leading to the emergence of "hybrid" pricing (a mixture of HH based and oil-linked pricing).

In the short-term, downward pressure on the oil indexation slope is expected to continue due to a combination of: supply competition, the shift in marginal supplies from Australia to other regions (e.g. East Africa) and the intrusion of HH linked contracts into the global LNG market. The average slope of oil-linked contracts in Asia Pacific in 2017 was 11.3% with some contracts having slopes in the 10% range. The current oversupply situation is not expected to last long and the market will recover over time. Modelling predicts that long-term slopes will gradually increase post 2020 to around 12%.

Global oil, gas and LNG price forecasts are shown to 2040 in the Figure below. Long-term (LT) oil-linked LNG prices in Asia are expected to closely track Brent and Japanese Customs Cleared (JCC) oil prices and are expected to become more expensive in the long term as oil prices trend upwards. Long-term HH linked prices in Asia are expected to be lower due to a low projected HH price in the US.

Figure 10-1 Forecast Oil, Gas and LNG Prices

$/MMBtu (Real $2016 terms)



Note: DES price at Japan*

10.2.3.2 Pricing for Mauritius

Oil-linked pricing for Mauritius will be generally available from LNG supply projects, aggregators and traders on conventional sized ships. The Bontang project in Indonesia and the MLNG project in Malaysia can load small ships and hence are likely sources of supply for Mauritius. These two projects are very traditional Asia Pacific projects and generally offer oil-linked pricing.

Henry Hub linked LNG for Mauritius may be available from aggregators or trading houses. Almost all of the HH linked supply is likely to originate from the US Gulf Coast. Theoretically, US projects have "sold" much of their LNG production capacity but, buying opportunities remain from projects in operation or under construction. In addition, about 50% of US LNG supply is contracted to aggregators and trading houses and is available in the secondary market.

Oil-linked prices were used as the basis for LNG pricing elsewhere in the Report and was considered the best basis to frame thinking on LNG prices for Mauritius.

10.2.4 LNG Procurement Overview

This discussion on LNG procurement is based on the situation where the Mauritius Government or a designated government owned entity purchases LNG. However, this might not be the most likely outcome as a private developer who builds and operates the LNG terminal could also be the regasified LNG supplier ex-terminal.

The LNG supply required in Mauritius is a relatively small amount initially, 240 kt/y growing to 500 kt/y near 2040.

It typically takes one to two years to go through the procurement process for an LNG Sale and Purchase Agreement (SPA).

Traditionally, there have been two common ways to purchase LNG: bilateral negotiations between a buyer and a seller or a tender style process with the buyer following a Request for Proposals process with multiple suppliers. Many governments or government owned entities follow an RFP process. With the current state of the market and recognising public procurement processes in Mauritius it would be expected that Mauritius would follow an RFP process.

In considering an RFP process, there are 20 to 30 LNG projects, aggregators and traders who could be issued with RFP documents. For large cargoes all the suppliers could be approached but for small cargoes only suppliers willing to load, or transport small cargoes could be considered.

There are many key terms in an LNG Sale and Purchase Agreement (SPA) but the most critical ones to be considered by Mauritius are: volume, term, responsibility for delivery and pricing:

- A volume of 300 kt/y would be a sensible base volume
- For Mauritius, where a long-term commitment will be required in parallel to an LNG terminal investment and as a long-term fuel supply to CCGT power plants a term of approximately 10 years would be sensible
- Responsibility for LNG delivery would be best left to the LNG supplier (Delivered ex Ship – DES)
- Pricing for Mauritius was described in the previous section. An oil linked formula is most common in the Asia Pacific region and in the Indian Ocean/South Asian/Middle East region where the nearest LNG buyers to Mauritius are located. Most LNG suppliers would be likely to offer LNG on an oil-linked basis
- Some suppliers may be willing to offer LNG prices based on a HH linkage or a hybrid approach (part oil and part HH linkage). On balance, while an oil-linked pricing formula would be suitable for Mauritius, there may be a favourable price impact from purchasing LNG

based on a HH linkage or a hybrid formula. As the lowest price possible for Mauritius is important it would be worthwhile seeking pricing proposals from suppliers on both an oil-linked and HH linked basis to explore the potential benefits of a HH linkage.

10.2.5 LNG Shipping

10.2.5.1 LNG shipping/supply options

A wide range of shipping options were considered for Mauritius including two LNG demand cases, six supply sources and four shipping arrangements. This range of options needed to be considered to allow a complete analysis of all shipping/terminal concept combinations. For example, some terminal concepts i.e. those with small storage capacity dictate that small parcel sizes on small ships will be required. The shipping study assumed an annual shipping requirement based on demand for LNG imports in Mauritius of 300 kt/y with a high case demand of 500kt/y.

The study considered several types of shipping arrangements:

- Full cargoes delivered on ships – typically with capacity assumed to be 160,000m³, which is the most standard ship size currently, or 125,000 m³ ships
- Partial cargoes delivered by LNG ships en-route to their final destination. Under this case, the ship capacity is also assumed to be 160,000m³ with a partial cargo being approximately 60,000 m³
- Full cargoes delivered by one mid- or small-scale LNG ship of 44,000, 24,000 or 10,000 m³ capacity
- Full cargoes delivered by two mid- or small-scale LNG ships.

The study analysed routes from six different LNG supply sources, selected on the basis of geographical proximity to Mauritius, LNG availability and ability to accommodate mid- and small-scale LNG ships. These sources were:

- Bonny (Nigeria): Bonny was used as the reference load port for partial cargoes from LNG ships en-route to India
- Mozambique offshore: this option was only considered feasible for LNG ships with capacity greater than 120,000m³ and is available only from 2023
- Mozambique onshore: this project is yet to be sanctioned, therefore this supply option was only considered applicable after 2025
- Ras Laffan (Qatar): considered as a possible source for large to mid-scale cargoes (125,000 to 160,000 m³
- Singapore: LNG would be reloaded onto mid- or small-scale LNG ships from the Jurong trans-shipment terminal
- Bintulu (Malaysia): Bintulu loads small-scale LNG ships on a regular basis so presents less technical and scheduling issues than the other sources.

10.2.5.2 LNG shipping costs

All the above options were modelled in Poten's proprietary shipping model.

For large cargoes, the shipping cost benchmark was estimated to be \$0.68/MMBtu for deliveries from Qatar. For partial, cargoes the shipping cost benchmark was estimated to be \$1.55/MMBtu from Bonny. For the mid-size ship (44,000 m³), the shipping cost benchmark is \$1.63/MMBtu from Bintulu as Bintulu is known to be a location where small and mid-size ships are regularly loaded. The cost benchmark for a 125,000 m³ cargo delivered to an FSU was estimated to be \$0.97/MMBtu, which allows for delivery from Qatar on a 125,000 m3 ship or a partially loaded large-ship possibly paying demurrage while the larger ship waits to discharge fully.

The results also show the potential attractiveness of shipping from Mozambique, if and when, Mozambique LNG becomes available i.e. shipping from Palma was estimated to \$0.35/MMBtu for large cargoes and \$2.18/MMBtu on the smallest ship considered (10,000 m^3).

In conclusion, shipping LNG to Mauritius is feasible on a wide range of ship sizes, 10,000 m^3 to 160,000 m^3. However, the results show there is a significant cost advantage in shipping LNG to Mauritius on large ships.

10.3 LNG TERMINAL SITE SELECTION

The Report covered LNG Terminal site selection considering the following topics: a review of available metocean data, a review of the entire Mauritius coastline, marine aspects of potential sites, onshore aspects of potential sites and pipeline routes.

10.3.1 Metocean Overview

Mauritius lies within the South-East Trade wind belt which extends from about latitude 30°S to 10°S and which generates seas of about 1-2 m in all seasons with waves up to 3-4 m during the period from July to September. The South-East Trades generate most of the swell conditions around Mauritius, but this may be supplemented by swells from further south, mainly coming from the south-west.

Winds will be typically 10-20 knots (kn) but on occasions get up to about 30 kn around Mauritius but this only lasts a few days at a time. The frequency of gales is about 5% throughout the year but can be 8-10% in July to September. Thunderstorms with winds of 30-40 kn are most common from December to March and will usually only last a few hours.

Tropical cyclones can also generate heavy seas and swells. The main cyclone period is from November to April with December to March being the most likely period. The probability of a cyclone occurring is one cyclone in every one and a half years.

Tide and current conditions around Mauritius pose no challenges.

10.3.2 Coastal Review

A detailed desk-top review of the coast of Mauritius was carried out using British Admiralty Charts, nautical publications and Google Earth to determine potential sites for an LNG import terminal. The review looked at all potential breaks in the fringing reef or where there were natural inlets along the coast.

This detailed review of the Mauritian coastline indicated that the only viable areas for an LNG import terminal are the Albion site and sites in Port Louis. These locations are typically protected from the South-East Trade winds.

10.3.3 Marine Site Review

10.3.3.1 Albion

The stretch of coastline between the Albion lighthouse and Pointe aux Sables to the north is an irregular coastline with sloping cliffs about 10-15 m high. Offshore, the water deepens relatively quickly, reaching about 40 m deep about 400 m offshore. This rapidly increasing water depth could present some difficulties for LNG jetty construction. A berth would most likely need to be built at an angle to the coastline (on an approximate east-west heading) or have a dog-leg shape, maintaining the berth pilings in no more than 20-25 m of water.

The dog-leg arrangement for the berth described above allows vessels to berth such that they are bow into the incoming swell off Albion providing the most comfortable, safe and secure mooring arrangement. The swell, generated by the South-East Trade winds or in the Southern Ocean, refracts around the southwestern tip of Mauritius and approaches the shore from a westerly direction along the Albion coastline, particularly at the south-west end where there is deep water close offshore. Towards the north-east end of the Albion coastline, shallow water extends further offshore, reducing the impact of the swell, causing it to refract further and approach the shore nearly perpendicular to the shoreline. The orientation of any berths along the Albion coastline therefore has to strike a balance between being head into the swell and staying in sufficiently shallow water for construction.

The Albion site is potentially a location for a petroleum hub that would include a jetty and onshore storage for oil products. If this development proceeds it would be possible to modify the oil product jetty to incorporate LNG ship berthing and unloading facilities. This arrangement could be for LNG ships supplying onshore storage or for a Floating Storage and Regasification Unit or Floating Storage Unit (FSRU or FSU) moored on the opposite side of the jetty to where oil product tankers would berth and discharge.

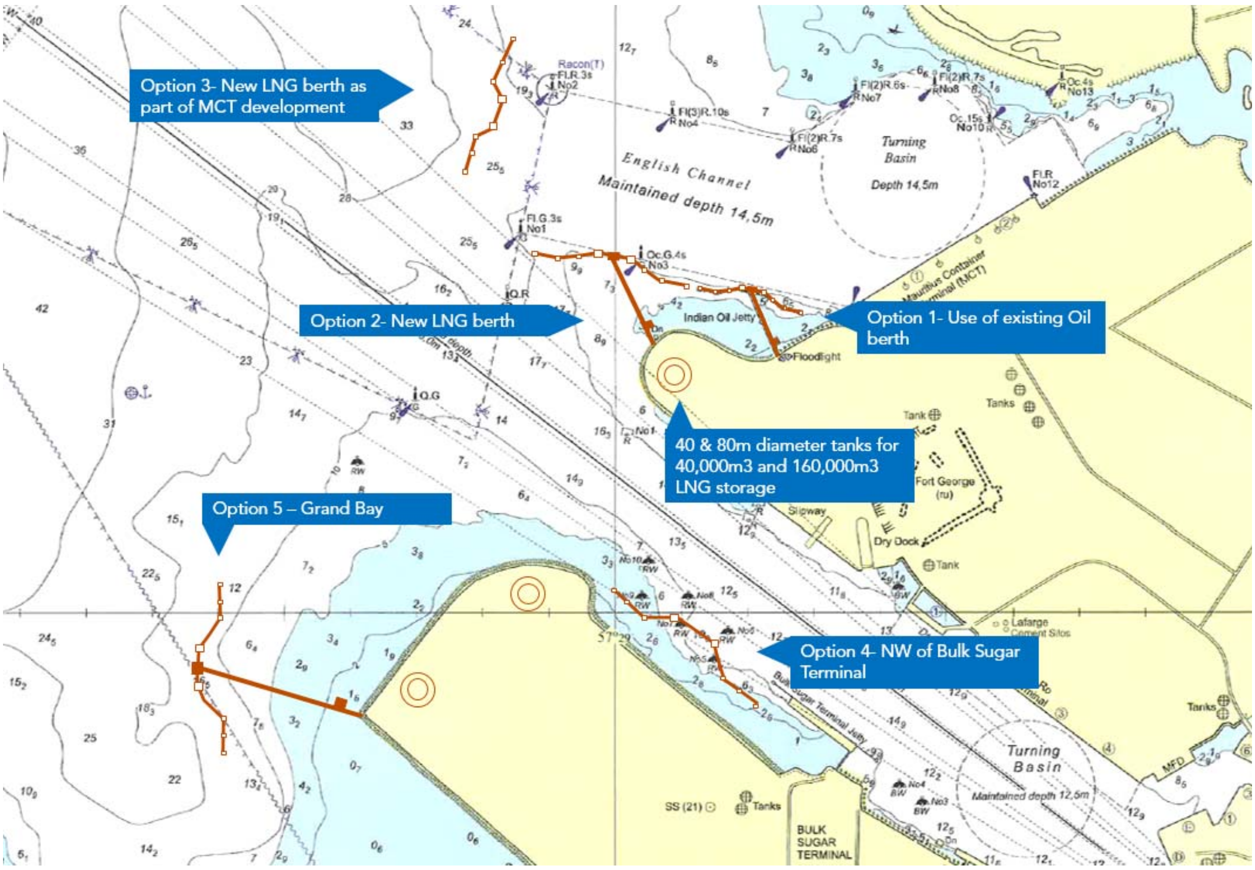
10.3.3.2 Port Louis

Recognising the requirement to keep the handling and storage of hazardous cargoes as far away as possible from the populated area of Port Louis, the site assessment has considered options to allow the importation (and possible re-export) of LNG from the port area. As shown on the chart below, five potential locations were identified at the outer extremities of Port Louis for an LNG berth and LNG storage.

The site assessment recognises that in respect of reclaimed land areas at both the north and south entrances of the port, the Port Master Plan has already allocated certain land areas to future uses. However, the site assessment adopted a "clean sheet of paper" approach unless there were existing commitments to other land users for Port land. As a project that is potentially of strategic importance to Mauritius, the site assessment has been conducted on the basis that the placement of an LNG terminal should be carefully considered first with adjacent land then being assigned to complementary and compatible industry use on a risk-based approach.

Near Port Louis, there is a shallow water shelf extending a considerable distance offshore that damps the swell conditions so that swell has less impact in Port Louis than at Albion.

Figure 10-2 Plan of Port Louis showing LNG berth options
(described in detail in the following sections)



Existing Oil/LPG Berth (Port Louis Option 1)

The oil/LPG Berth is located close to the entrance to English Channel and the Mauritius Container Terminal (MCT) and was designed for vessels up to 210 m length overall (LOA) although it is used to berth vessels up to about 228 m LOA. If this berth were to be considered for LNG imports, the berth may prove suitable for small and mid-scale LNG ships but would need to be expanded with additional breasting dolphin(s) and mooring dolphins (or buoys). The management of any modification works on the berth would need to avoid any conflict with its existing use for petroleum product and LPG imports. In addition to the possibility of requiring additional breasting dolphins and other structural work (e.g. additional mooring dolphins) for LNG ship handling, the berth is likely to require significant upgrades for LNG operations. An FSRU cannot be located on this berth as it would prevent oil products and LPG tankers using the berth.

New Berth (Port Louis Option 2)

This would be a berth, either full sized or scaled down for smaller vessels, located immediately west-north-west of the existing oil/LPG berth with the berthing face parallel and coincident with the south side of English Channel. At this point, the channel is 350m wide and the use of a berth here for LNG imports (and possible re-exports) would not hamper shipping coming in and out of the container terminal, even with an FSRU/FSU and LNG ship alongside, occupying about 100m of the channel width.

The berth would be connected to the shore by a trestle jetty approximately 230 m long, with the berth being in 14.5 m water depth which is a maintained dredged depth for the container terminal and ideal for the LNG berth. The berth could be sized appropriately to the proposed vessels supplying LNG and could be designed to accommodate small, mid and large-ships as well as a large-size FSU or FSRU.

The main disadvantage of this location is that if the MCT expansion goes ahead as planned and the approach channel is substantially realigned as envisaged in the Port Master Plan, the berth proposed as Option 2 could conflict with these future plans.

New Berth (Port Louis Option 3)

This option was not considered in detail as it would be located on the breakwater of a potential MCT expansion. The MCT expansion is uncertain in terms of timing, or whether it proceeds at all, and would not support the timely start-up of an LNG terminal.

New Berth (Port Louis Option 4)

This option was also not considered in detail as there is limited room to turn an LNG ship near the berth and a moored LNG ship could create navigation challenges for ships passing by to enter the Port Louis inner harbour.

New Berth (Port Louis Option 5)

The Option 5 berth would involve a berth extending west-north-west from the western tip of the reclaimed land area at the southern side of the harbour entrance. A trestle jetty extending about 420m offshore would result in a berthing line on a north-south heading in a natural depth of about 14m with deeper water lying west of the berth. An LNG ship could be turned in about 25m of water and maneuvered alongside the berth without any dredging requirements.

Of the berth options considered in the Port Louis area, Option 5 represents possibly the simplest and easiest solution from a berth location perspective and lends itself to all sizes of ship and FSU/FSRUs. The construction of either a sea island or berth with trestle access to shore has no impact on other shipping activities in Port Louis and there are no dredging requirements.

Offshore Option

The remaining option close to Port Louis is an offshore location about 3 km to the west of Port Louis and part of the existing anchorage area available to the port. An offshore location would require a 500m radius safety zone or restricted area around it to avoid encroachment from other vessels and the pipeline corridor to shore would also become a restricted area where there would be no anchoring or fishing, even if the high-pressure gas line is trenched into the seabed.

Options for mooring an FSRU at this offshore location are to have it capable of weather-vaning, or to hold it on a fixed heading using an appropriate mooring system. Given that extreme wave heights can come from a westerly direction during the passage of a cyclone, a dis-connectable mooring system would be required so that the FSRU could put to sea for safety during a cyclone. If this was required, it would result in some unavoidable disruption to gas supply when the FSRU is off station but this is not unique to Mauritius.

10.3.4 Onshore Site Selection Review

In conjunction with the review of possible locations for LNG terminal marine facilities the site assessment also reviewed onshore aspects at the LNG terminal locations preferred from a marine point of view. The assessment considered the availability and suitability of land adjacent to the proposed berthing facilities and pipeline routes to the major gas consumers which are the CEB power plants.

The marine site selection produced five feasible berth locations. For the purposes of an onshore assessment, these five locations can be grouped into three onshore areas as follows:

- North Harbour – Port Louis berth Options 1 and 2
- South Harbour – Port Louis Option 5 and the Offshore Option
- Albion.

These three onshore sites are shown in the figure below.

The CEB power plants to be potentially supplied with gas are a new CCGT plant at Fort George, the Fort Victoria and Saint Louis fuel oil plants and in future further CCGT plants. The Report indicates that initially the major consumer of gas will be the CCGT power plant at Fort George. It is key to get gas to this plant at its start-up in CCGT mode.

Figure 10-3 LNG Terminal Onshore Sites

10.3.4.1 North Harbour site

The North Harbour site is an area of reclaimed land at the north-west entrance to Port Louis harbour (shown in the Figure below). The site is approximately 2.5 hectare (ha) which should be sufficient for small or mid-size onshore LNG terminal facilities but will not be sufficient for large-size terminal facilities. The site is remote from Port Louis city and is surrounded by like activities i.e. the oil/LPG jetty, a petroleum products tank farm and a bulk LPG storage facility.

From a planning perspective the land is within the Port Louis port area and is controlled by the Mauritius Port Authority. While normal regulatory approvals processes will need to be followed e.g. planning, safety, environmental and social impact, the process should be relatively straightforward as the port area is essentially an industrial area tolerant of developments like an LNG terminal. Road access to the site is through the port area.

The site has been recently reclaimed and a geotechnical assessment will be required to establish soil conditions before civil design can proceed. However, it is not uncommon to construct LNG facilities on reclaimed or "soft" land.

Figure 10-4 North Harbour Terminal Location

10.3.4.2 South Harbour site

The South Harbour site is an area of reclaimed land at the south-west entrance to Port Louis harbour (shown in the Figure below). The proposed site is approximately 12 ha which should be enough for small, mid or large-size onshore LNG terminal facilities. Another 10-20 ha of land could be available for installing additional CCGT plants, but it would require the MPA to revise their Port Master Plan as the area is currently earmarked for other future developments.

The site is remote from Port Louis city and is an isolated area. If this site is selected for the LNG terminal, re-planning would be required to assess what activities would be suitable outside the boundary of the LNG terminal. From a planning perspective the land is within the Port Louis port area and is controlled by the Mauritius Port Authority. While normal regulatory approvals processes will need to be followed e.g. planning, safety, environmental and social impact, the process should be relatively straightforward as the port area is considered an industrial area tolerant of developments like an LNG terminal. Road access to the site is via the roads to the bulk sugar terminal and Fort William oil storage tank farm. Some parts of the road leading to the motorway pass through residential/commercial areas.

The site has been recently reclaimed and a geotechnical assessment will be required to establish soil conditions before civil design can proceed. However, it is not uncommon to construct LNG facilities on reclaimed or "soft" land.

Figure 10-5 South Harbour Terminal Location

10.3.4.3 Albion site

The Albion site is a greenfield area approximately 8 km south-west of the entrance to Port Louis harbour. The area is being considered as a site for a petroleum hub development that could include an LNG terminal, a petroleum storage facility and power plants. The total area of available land is approximately 400 ha located to the north-east of the Albion Lighthouse. The land is 15 to 20 m above sea-level at the shoreline which is a rocky slope. The proposed site is approximately 12 ha which should be enough for small, mid or large-size onshore LNG terminal facilities.

The site is in a remote area with minimal nearby activity. From a planning perspective, some of the land is government owned but the majority is privately owned. The Ministry of Housing and Lands is progressing planning processes through a Subject Plan for the development of the area including an oil terminal, a power plant, an LNG terminal. a PV solar project and road infrastructure. The plan covers 410 ha including 260 ha for buffer zones. Following approval of the Subject Plan other regulatory approvals processes will need to be followed e.g. safety, environmental and social impact. The process could be relatively straightforward as the Subject Plan deals with key issues such as zoning and buffer zones. However, the acquisition of private land will take time and there is scope for local opposition. In the past a coal fired power plant, to be located at a similar location, was cancelled for several reasons including strong local opposition. This situation makes the development of an LNG terminal at Albion more problematic than developments in Port Louis where the land is already part of the Port.

Road access to the site is limited but the Subject Plan considers construction of new roads. The site is a considerable distance from Port Louis by road and LNG road tankers would have to navigate narrow roads and residential areas to get to the motorway.

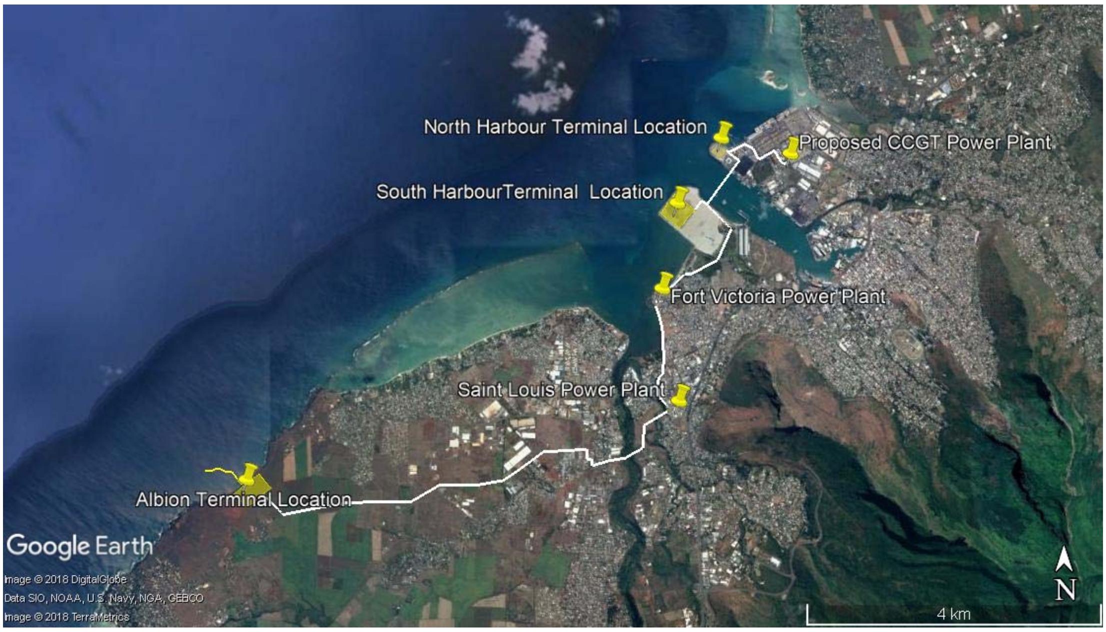
Figure 10-6 Albion Terminal Location

10.3.5 Pipeline Routes

The site assessment considered possible pipeline routes from each of the potential LNG terminal sites to the CEB power plants that could be significant consumers of gas. There are three firm CEB power plants that have good potential to consume gas: Fort Victoria, Saint Louis and the proposed CCGT plant at Fort George.

The pipeline routes were reviewed to identify any major risks associated with each route. The routes appear feasible, although some are more challenging than others. The routes between Fort Victoria and Saint Louis and Saint Louis and Albion have right of way and constructions issues to overcome. The routes are intended to be indicative and further work will be required later to consider the routes in greater depth for constructability and right-of-way issues. An overview of the potential pipeline routes is shown in the Figure below.

Figure 10-7 Pipeline Routes from Terminals to Power Plants



10.3.6 Site Selection Summary

The Report reviewed potential sites for marine berths and onshore LNG facilities. Five marine/onshore site combinations were considered in detail and all are feasible.

In summary, each marine/onshore site alternative has a range of pros and cons, and all are considered feasible. The pros and cons at each site tend to balance each other such that no particular alternative stands out from the others. On this basis the cost of an LNG terminal concept should be the most important factor in deciding the preferred site and terminal combination.

10.4 LNG TERMINAL CONCEPTS

The Report reviewed LNG terminal concepts for three onshore sites and five berth locations: North Harbour (Option 1 - existing oil/LPG jetty and Option 2 - new jetty), South Harbour (Option 5 - new jetty and offshore) and Albion.

For each site/berth combination a range of concepts were assessed by considering the following key components:

- LNG ship size (10,000, 24,000, 44,000, 125,000 and 160,000 m3)
- Berth types (jetty or offshore)
- Onshore LNG storage options (40,000, 75,000 and 175,000m³)
- Offshore storage (FSU) and offshore storage and regasification (FSRU)
- Regasification rates (60 and 90 million standard cubic feet/day (MMscf/d))
- LNG ship and truck loading.

The concepts were screened based on terminal tariff and associated shipping cost.

10.4.1 Terminal Concepts and Results

A total of 28 concepts were analysed: 14 at North Harbour, 9 at South Harbour and 5 at Albion.

The two best concepts for each site/berth alternative were shortlisted for comparison. These shortlisted options are described in the table below.

Table 10-4 Short-Listed Concept Descriptions

Case ID	Concept No	Location	Storage	LNG Ship Limit	Regasification Rate
Opt1-OS75-44-60	1.1	Existing Oil/LPG Berth	75,000 m^3 onshore	44,000 m^3	60 MMscf/d
Opt1-OS75-160-60	1.2	Existing Oil/LPG Berth	75,000 m^3 onshore	160,000 m^3	60 MMscf/d
Opt2-FSU138-125-60	2.1	New Berth	138,000 m^3 FSU	125,000 m^3	60 MMscf/d
Opt2-OS75-160-60	2.2	New Berth	75,000 m^3 onshore	160,000 m^3	60 MMscf/d
Opt5-FSU138-125-60	5.1	South Harbour	138,000 m^3 FSU	125,000 m^3	60 MMscf/d
Opt5-OS75-160-60	5.2	South Harbour	75,000 m^3 onshore	160,000 m^3	60 MMscf/d
Off -FSRU75-160-60	O.1	Offshore	75,000 m^3 FSRU	160,000 m^3	60 MMscf/d
Off -FSRU175-160-60	O.2	Offshore	175,000 m^3 FSRU	160,000 m^3	60 MMscf/d
Albion-FSU138-125-60	A.1	Albion	138,000 m^3 FSU	125,000 m^3	60 MMscf/d
Albion-OS175-160-60	A.2	Albion	175,000 m^3 onshore	160,000 m^3	60 MMscf/d

Based on screening terminal tariffs alone the lowest cost concepts are the two concepts at North Harbour using the existing oil/LPG berth and mid-sized onshore storage. This is due to the lower capital costs in upgrading the jetty compared to a new build jetty and the lower cost of building a mid-sized LNG tank compared to larger storage. However, these concepts with mid-sized storage require the use of 44,000 m^3 ships or partial cargoes (60,000 m^3) which have a high shipping cost. The total tariff for these concepts, after including shipping costs is not the lowest. This demonstrates an important finding. In looking at the total tariffs for different concepts, generally the cost savings in down-sizing terminal facilities are outweighed by higher shipping costs associated with the smaller ship or partial cargoes required to match the smaller LNG storage size.

Based on the total tariff (for terminal and shipping) the lowest cost concept is a 138,000 m^3 FSU at North Harbour receiving cargoes on relatively small conventional ships i.e. 125,000 m^3 cargoes. The FSU would be a leased second-hand vessel moored at a new jetty adjacent to the existing oil terminal and an onshore regasification plant on the North Harbour site. The cost of delivering cargoes on a conventional ship is lower than the shipping costs associated with the small ships or partial cargoes. This lower shipping cost outweighs the higher LNG terminal capex and FSU leasing costs when compared to the concepts with mid-sized storage. This concept would be very similar to an FSU LNG terminal developed at Delimara in Malta shown in the Figure below.

Figure 10-8 FSU based LNG Terminal, Delimara, Malta

The spread in total tariffs is relatively small between the five lowest cost concepts ie the fifth lowest cost concept (an FSU at Albion) is only 6% more expensive than the lowest cost option. Hence, there is a range of potential concepts that have a relatively similar cost.

The two next lowest cost concepts are:

- Receiving cargoes on 44,000 m^3 LNG ships at the existing but upgraded oil/LPG terminal at the North Harbour site with mid-sized onshore storage and onshore regasification
- A similar concept to the lowest cost option (an FSU at North Harbour) but moved to South Harbour.

The best Albion based concept is also a similar concept (an FSU at North Harbour) but moved to Albion.

Four jetty sensitivities were considered for Albion as Albion concept options could potentially benefit from sharing the cost of the jetty with other users.

- An FSU concept at Albion would require a dual berth jetty. Sharing the cost of a dual berth jetty on a 50/50 basis with another user could lower the tariff
- For a concept at Albion with 175,000 m3 of onshore storage that only needs intermittent access to the jetty, a reasonable assumption would be that the LNG terminal would only pay to access a single berth jetty when a ship is expected. On this basis, sharing the cost on a 25/75 basis with other users has been assumed which could also lower the tariff
- For both the above options, if the LNG terminal did not have to pay any capex associated with the jetty, the respective tariffs would decrease further.

Sensitivities were also run to test the effect of greater terminal throughput. Several cases were run at a greater capacity (500 kt/y, 90 MMscf/d) and on average, terminal tariffs (excluding shipping) dropped by approximately 40%. This highlights the importance of achieving greater terminal throughput, for example in the transportation and LNG bunkering segments where a significant throughput difference could possibly be achieved.

10.4.2 Pipelines

The routes for installation of the pipelines were discussed in detail in the Report and can be considered in two segments:

- A pipeline interconnecting the existing power plants at Fort Victoria, Saint Louis and the proposed CCGT plant at Fort George (which also includes the North and South Harbour sites)
- A pipeline connecting Albion to Saint Louis which will give access to the other plants through the interconnecting pipeline.

A single diameter was selected for the pipeline based on a forecast maximum flow rate of 90 MMscf/d, which results in a pipeline diameter of 12 inches.

The pipeline routes were divided into sub-sections, each of which was characterised in terms of complexity of pipeline construction and separately costed to provide a total capital cost estimate. This has been converted into an indicative tariff for combination with terminal costs, based on a throughput of 60 MMscf/d.

The indicative cost and the tariff for the pipelines is relatively low compared to the cost of the terminal and shipping. The indicative tariff for the pipelines to connect the existing power plants at Fort Victoria, Saint Louis and the proposed CCGT plant at Fort George is estimated to be $0.06/MMBtu. The indicative tariff to connect Albion to Saint Louis which will give access to the other power plants is also estimated to be $0.06/MMBtu. These tariffs are considered to be indicative as only limited visual route surveys have been carried out and the final configuration of the pipeline network is yet to be determined.

10.4.3 LNG Sites, Concepts and Pipelines Conclusions

The LNG terminal concept section found that multiple concepts would deliver LNG to Mauritius at a similar tariff. However, on a tariff basis the preferred concept was Concept 2.1 - a 138,000 m^3 FSU on a new jetty with cargoes (125,000 m^3) delivered on conventional ships and an onshore regasification plant on the North Harbour site.

In addition to the pros and cons described in the site selection section for the North Harbour site there are additional pros and cons associated with the FSU concept. The FSU concept has the following advantages. The concept has the lowest cost of all concepts studied and it is proven concept. The concept has relatively large storage that allows standard industry ships to deliver cargoes at a relatively low shipping cost. By adopting larger storage and conventional shipping Mauritius should be in a better negotiating position in dealing with LNG suppliers. The large storage provides capacity for Mauritius to better manage LNG supply disruptions and supports future growth opportunities.

The FSU concept also has disadvantages. The main concern being that during cyclones the FSU must put to sea and cease LNG supply to shore. For the Fort George CCGT, Fort Victoria and Saint Louis there is existing storage capacity to hold liquid fuels as backup. Any additional CCGTs would also need to include liquid fuel storage as a backup. Alternately, a small onshore LNG storage tank (approximately 10,000 m^3) could be built to provide backup for the expected number of days that the FSU would be at sea.

One of the two concepts that was in equal second place in terms of total tariff was Concept 1.1 - which is based on cargoes on 44,000 m^3 LNG ships at the existing, but upgraded, oil/LPG terminal at the North Harbour site with mid-sized onshore storage (75,000 m^3) and onshore regasification. This concept has the following advantages. By using the existing berth, albeit with significant upgrading, and adopting mid-sized storage tanks this concept has the lowest capital cost and terminal tariff. However, shipping costs are high, although this cost is an operating cost rather than an upfront capital cost. There is some potential upside in this concept in relation to shipping costs. The estimated shipping cost for 44,000 m3 ships is high and based on the cost of building a new ship. There is some potential that an older mid-sized LNG ship could be purchased to lower the shipping cost, but such ships are rare. The other advantage of this concept is that it is a conventional onshore terminal which has high reliability in terminal performance and as the storage is onshore it would be expected to maintain supply during cyclones. The only disadvantage with this concept is the storage size. While it is adequate for the LNG demand cases considered, larger storage provides greater supply security and growth potential.

The other concept that was in equal second place in terms of total tariff was Concept 5.1 - which is like Concept 2.1, an FSU with an onshore terminal, but moved to the South Harbour site. The pros and cons for this concept are like those for Concept 2.1. There are two other potential advantages. The South Harbour berth is more remote and clear of other Port Louis shipping traffic. If port traffic was considered an issue for Concept 2.1 at North Harbor any concerns would be removed for a small additional cost by moving to South Harbour. The other potential advantage at South Harbour is that it offers space for a combined LNG terminal/CCGT power station precinct.

The fourth ranked concept in terms of total terminal tariff is Concept 1.2 – which is similar to Concept 1.1 (using the existing oil/LPG berth at North Harbour with a mid-sized storage tank) but expanding the berth to take large LNG ships (160,000 m^3) delivering partial cargoes (60,000 m^3). There is some potential upside in this concept in relation to shipping costs. The estimated shipping cost for partial cargoes is high and based on realistic market assessments. However, is possible that an LNG supplier might view a potential LNG sale, shipping and terminal combination in a manner that they could lower the shipping cost for partial cargoes.

The fifth ranked concept in terms of total tariff is Concept A.1 - which is similar to Concept 2.1, an FSU with an onshore terminal, but moved to the Albion site. There is some potential upside in this concept in relation to terminal costs. An FSU concept at Albion would require a dual berth jetty but sharing the cost of a dual berth jetty on a 50/50 basis with another user could lower the tariff by 3% to bring it closer to the lowest cost option. In addition, if a future Government policy decision places additional CCGTs at Albion they would be adjacent to the LNG terminal.

The second-best Albion concept is Concept A.2 – an onshore terminal with a large storage (175,000 m^3). This concept has the same advantage as Concept 1.1 (an onshore terminal at North Harbour) i.e. a conventional onshore terminal which has high reliability in terminal performance and as the storage is onshore it would be expected to maintain supply during cyclones. There is also some potential upside in this concept in relation to terminal costs. A terminal with onshore storage at Albion only needs intermittent access to the jetty with a single berth (approximately five shipments per year). It would be reasonable to assume that the LNG terminal would only pay to access the jetty when a ship is expected. On this basis, sharing the cost on a 25/75 basis with other users has been assumed which could lower the tariff by nearly 10% and bring the tariff cost closer to the lowest cost alternative. However, for both the Albion cases there is uncertainty about whether and when there will be a jetty developed by others at Albion.

The pipelines required to connect the LNG terminal to the power plants don't appear to be a decisive consideration. The costs of pipeline development are small compared to the cost of the terminal and shipping. Potential pipeline routes were reviewed to identify any major risks associated with each route. The routes appear feasible, although some are more challenging than others. The development of a pipeline between Albion and the Saint Louis power station would need to be carefully managed. However, to keep the challenge in perspective, the Albion to Saint Louis pipeline is a relatively small diameter pipeline and just 7 km in length. This would be considered a very straightforward pipeline development in countries where a gas industry already exists. All terminal concepts require a similar pipeline network between Fort George and Albion. The only exception would be if future CCGT power plants were to be located at the South Harbour site rather than Albion, then a pipeline to Albion would not be required for the concepts in the Port Louis area.

Many concepts were considered, and a number of potential upside opportunities were identified. As more detailed work proceeds on an LNG terminal there appears to be reasonable prospects of optimizing further e.g. optimizing storage tank size/costs and shipping costs.

In conclusion there are multiple concepts that have a relatively similar cost in terms of total tariffs. There are differences between pros and cons of the concepts but on balance they do not justify moving away from the lowest cost concept, an FSU at North Harbour, as the preferred option.

However, in saying this the feasibility study has been prepared based on general LNG market and industry knowledge not on the basis of the specific strategies that could be adopted by potential LNG suppliers and terminal developers. With this in mind the LNG terminal developer should be given the opportunity to propose what it thinks will be the best concept for an LNG terminal in Mauritius as a tool to further lower the LNG supply/terminal development cost structure. In going down this path the Government would need to set some key boundaries for the process after evaluating this feasibility study e.g. in terms of terminal site and fundamental performance parameters i.e. minimum storage volume and gas send-out requirements.

10.5 CONVERSION TO LNG

The Report reviewed the potential to convert coal and heavy fuel oil users to LNG. The demand data from converting energy users to LNG has been reviewed in the assessment for the demand of LNG - Section 10.1 above. Findings other than those related to the demand for LNG are discussed in this section.

10.5.1 Power Generation Conversion

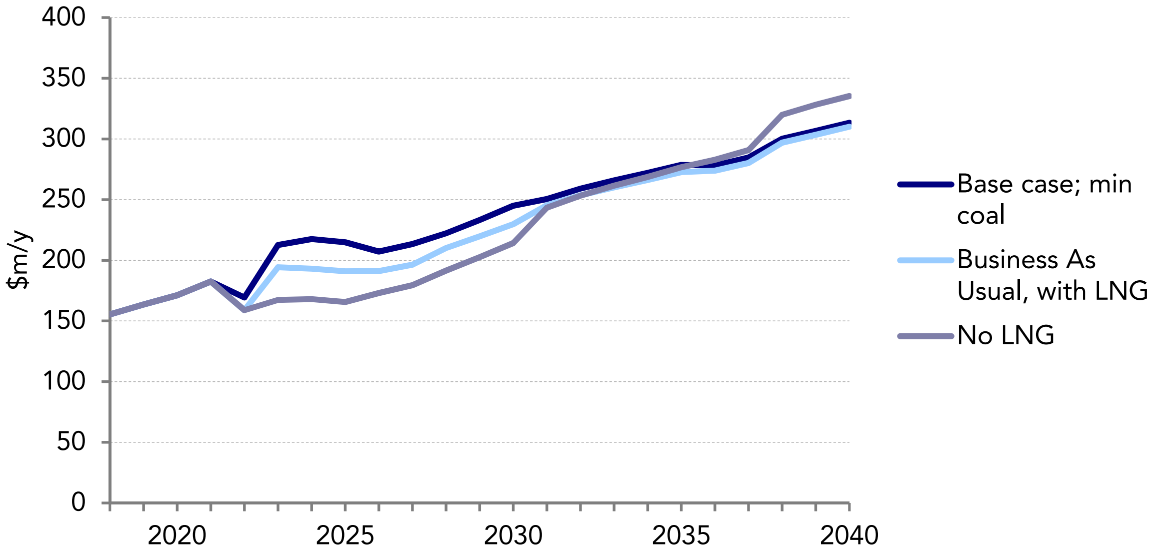
The power generation base case assumed that generation from coal will be minimised consistent with the CEB's PPAs with the IPPs and PPA renewals would be for bagasse fueled power only. In addition, the Saint Louis and Fort Victoria power plants would be converted to gas. A low case for power generation with LNG was built on the basis that coal burning continues on a "business as usual (BAU) basis" i.e. maximizing coal burning in the IPPs. In addition to these two power generation cases, a no LNG case was prepared particularly to compare from a cost perspective.

10.5.1.1 Fuel Costs

The cost of importing fossil fuels for power generation was calculated in the Report from projected fuel prices and estimated fuel consumption by each plant and each fuel. Infrastructure costs were added for the LNG terminal, for pipelines and for power plant conversions (Saint Louis and Fort Victoria). The total cost of fossil fuels and LNG related infrastructure for the three cases is shown in the Figure below.

The total cost in the base case over the period 2018 to 2040 would be $5.4 billion (5 % more than with no LNG), $5.2 bn for the BAU Case (1 % more) and $5.2 bn for the No LNG Case. In the initial years of switching to LNG the costs of fuel (including infrastructure) are significantly higher than the no LNG case. However, in the longer term this position reverses and the cost of fuel in the LNG cases becomes lower.

Figure 10-9 Fossil fuel costs
Fuel import bill + infrastructure



These fuel price differentials would be expected to have an impact on electricity prices. After 2030, electricity prices in all cases become similar and after 2035 prices in the LNG cases become cheaper.

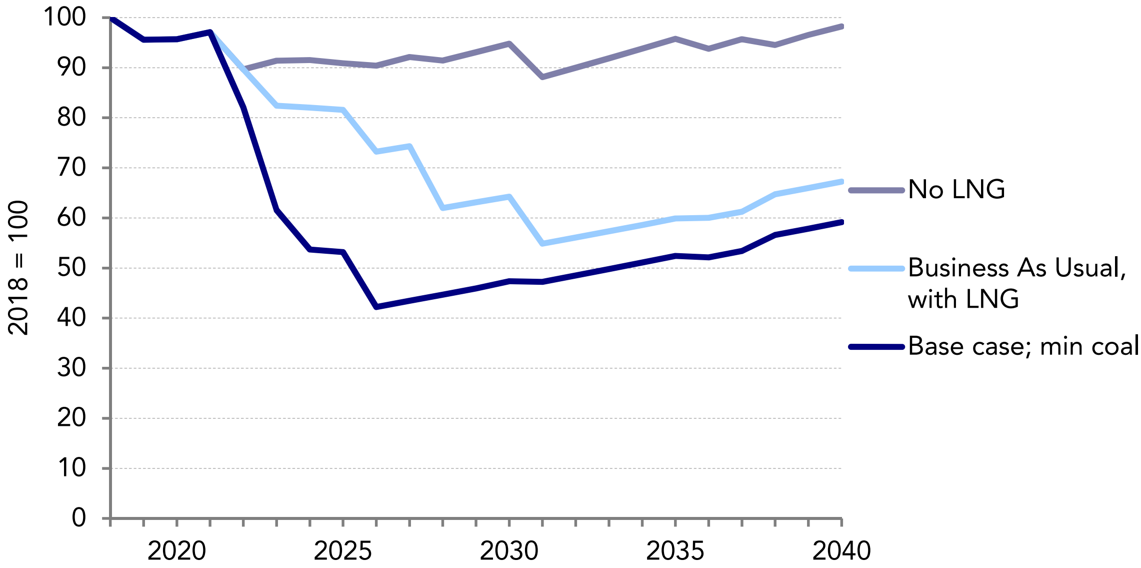
10.5.1.2 Emissions

The introduction of LNG would reduce emissions significantly. In addition to essentially eliminating emissions of sulphur oxides (SO_x) and particulate matter and reducing nitrogen oxides (NO_x) emissions by about 85 %), it would also reduce CO_2 emissions by up to 50 % as shown in the figure below.

Switching to LNG would result in more efficient use of fuel and a significant reduction in greenhouse gas emissions. CO_2 emissions would be 15.6 million tons lower over the period to 2040 in the Base Case compared with a no LNG case.

Figure 10-10 CO_2 emissions for Base Case, Business As Usual and No LNG cases

Base year 2018 = 100



10.5.1.3 Power Generation Conversion Conclusion

Almost all LNG use in Mauritius will be in power generation, particularly in the initial years after start-up of an LNG terminal. So, the question of the feasibility of LNG really hangs off its feasibility in power generation.

The two key points are that Mauritius can switch to LNG as a fuel for power generation for a small increase in total costs (5%), including the cost of LNG infrastructure, and achieve a significant reduction in total greenhouse gas emissions (15%). This can be concluded as being feasible.

10.5.2 Industrial, Commercial and Residential Conversion

The Report assessed that the demand for LNG from the industrial sector would be modest as LNG is expected to be more expensive than HFO on a delivered basis.

To increase demand in the industrial segment, would either require taxes on fossil fuels based on their level of emissions (thereby increasing the price of coal and heavy fuel oil) or by subsidising the price of LNG for industrial users. The former approach could be counterproductive where Mauritian industry is often competing in international markets (eg textiles) and is therefore price sensitive. Nevertheless, once the path to LNG is clear, the Government should consider means of making LNG available to industry by running a process seeking expressions of interest from private parties and selecting one of those parties, to distribute and market LNG, using an RFP process.

The demand for LNG in the commercial and residential sectors is expected to be negligible and it will be difficult to find ways of encouraging demand. However, in both the commercial and residential sectors the most widely used form of energy used is electricity. Therefore, rather than trying to establish LNG distribution in these sectors, encouraging the use of electricity that is produced from LNG, could be a better way to increase the demand for LNG. For example, the government could promote all electric homes.

10.5.3 Transportation Conversion

In the transportation sector, LNG has good prospects as it could be cheaper than both gasoline and diesel delivered into the transportation sector. However, take up of LNG is expected to be slow because of vehicle owner inertia and other barriers particularly for the light vehicle sub-sector.

It is possible that the demand for LNG in the transportation sector could be significantly increased with strong government policies to promote the use of CNG and LNG vehicles. For example, this could follow the current trend in Europe where cities are placing near-term bans on diesel cars and in the long-term new vehicle sales will be banned for vehicles with gasoline or diesel engines. The Government can also focus on price signals that encourage CNG/LNG use e.g. by keeping fuel and vehicle taxes on LNG lower than on diesel and gasoline.

For heavy-duty vehicles, there is a greater probability of increasing LNG demand as LNG has a greater advantage over diesel in terms of pricing and the barriers against LNG/CNG in heavy-duty vehicles are lower than for light duty vehicles. Bus fleets are a prime example where LNG/CNG could make good inroads. For buses, the Government could mandate bus fleets switch to LNG/CNG and could take the lead by switching the government owned bus fleet to LNG/CNG e.g. the National Transport Corporation's 500 buses. Demonstrated examples of success in using LNG/CNG will be important to increasing penetration rates for LNG.

To operate vehicles on LNG/CNG will require a distribution system. The government should run a combined expressions of interest/RFP process to distribute and market LNG for the industrial and transportation sectors.

10.6 LNG TERMINAL COMMERCIAL, IMPLEMENTATION AND FINANCING

10.6.1 Commercial Structures

There are three basic commercial structures that can be applied to both land-based and floating terminals. These structures are:

- An integrated model – LNG supply, terminal operations and marketing of regasified LNG are all controlled by a single entity or joint venture
- A proprietary model (utility structure) – an entity (LNG Buyer) purchases LNG, operates the terminal and markets regasified LNG
- An unbundled model (tolling structure) – The owner of the terminal provides an unloading, storage and regasification service to other companies who buy LNG and sell regasified LNG.

The Report proposed developing the project using an integrated structure for the LNG import terminal i.e. one nominated company will build the infrastructure on a build own and operate (BOO) basis. The same company would arrange LNG supply and deliver regasified LNG to customers. The major advantage for Mauritius in adopting an integrated structure is that it will allow the chosen developer to optimise the value chain. This is particularly important given the small size of the terminal and small quantity of gas needed by the Mauritius market. An integrated developer can optimize supply, shipping arrangements and storage utilisation. Another advantage in adopting an integrated structure is that the commercial and technical complexities of developing an LNG import project can be left to an experienced LNG player i.e. one with extensive LNG supply/procurement, shipping and terminal experience.

To achieve the best outcome for Mauritius, the procurement process will need to create a competitive environment. This will require a tender process to select the terminal developer/gas supplier. Government control of the terminal developer/gas supplier will be maintained through negotiating a BOO agreement for the terminal, setting a regulatory framework and negotiating a GSA for the supply of regasified LNG (through the CEB). A build own operate and transfer (BOOT) arrangement is also possible.

10.6.2 Project Implementation

Implementing an LNG terminal in Mauritius should follow a number of steps in sequence. The core element of the implementation process should be a tender/RFP process to select a terminal developer.

10.6.2.1 Confirm project structure

Once the LNG terminal project's viability has been confirmed and the Government makes a decision to proceed, the first step will be for the Government to settle on the project structure as the implementation path depends on the chosen structure. For the implementation section of the Report the project structure was assumed to be an integrated project structure using a private developer.

10.6.2.2 Stakeholder buy-in

Decisions on the LNG import terminal need to be "owned" by all the relevant stakeholders. Without this ownership, the project may suffer delays as different stakeholders are brought on board. Key project stakeholders will include: Government heads, key ministries, government entities such as the CEB, MPA, STC etc, regulatory bodies, private sector companies e.g. oil companies, NGOs, the media and the public. A plan will be required to manage each stakeholder group and show how their buy-in to the decision will be obtained.

10.6.2.3 Project parameters and data

Essential initial steps in the implementation process are to define the project and obtain the data needed for the project.

Project Definition

Key project parameters will need to set up-front. These will include: gas volumes required, maximum and minimum daily send out required and seasonality of demand, the extent of take or pay commitment to be offered, the duration of the project, LNG storage volumes, regasification and send out options from the terminal e.g. pipeline routes, trucking, etc.

Terminal proponents should be encouraged to offer innovative (but reliable) alternative solutions but the project parameters should also include an outline of a preferred solution: location, floating terminal or onshore and size of terminal.

Project Data

The government entity who will request proposals for the LNG terminal development should first gather the data needed for the design of the LNG terminal. This type of data would include specific metocean data, including wave data for the proposed location and geotechnical data on the site. This data may be replaced during the detail design process by more detailed surveys, but it should be sufficient at the RFP stage to enable accurate proposals to be made. The data required may include: survey data, climate data, metocean data, pipeline design data, and socio/environmental survey data.

10.6.2.4 Terminal developer selection

If the Government chooses to proceed with an LNG project, on the basis of an integrated structure with a private developer, an overview of the steps to be followed is outlined below.

Project promotion

The terminal developer selection process should commence with Mauritius creating interest in a project through initial meetings and a non-confidential project pitchbook. The pitchbook would summarise the project and assist in generating interest in the project. The objective will be to present Mauritius as an attractive LNG end user. Initially this will require raising the project's profile by: general publicity on the need for LNG in Mauritius, a road-trip to promote Mauritius as an LNG demand centre and where possible conference presentations.

Long list of potential developers

The Project promotion phase will generate approaches from a wide variety of companies i.e. Mauritius could attract considerable interest. Many LNG players should find Mauritius LNG demand to be an attractive market and it is expected many would be willing to act as a developer for the project. The list below is an example of the companies that may be interested:

- LNG suppliers/majors: Shell, BP, Chevron, ExxonMobil, Gaz Natural, Gazprom, Engie, Eni, Total, Qatar Petroleum, Woodside, Sempra, Cheniere and Petronas
- LNG buyers: Centrica, E.ON, Fluxys, GAIL, Petronet, IOC, Kogas, GS Energy, SK E&S, JERA, Osaka Gas, Tokyo Gas, Pavilion Gas, PetroChina and CNOOC
- Traders: EDFT, Itochu, Marubeni, Mitsubishi, Mitsui, Sojitz, Sumitomo, Trafigura, Vitol, Gunvor and Glencore
- FSRU/FSU providers: BW Gas, Golar, Hoegh, MOL, Maran Gas, Gaslog, Dynagas, MISC, Teekay, Bumi Armada, NYK, K-Line and Exmar
- Mid-stream/storage players: Vopak, Wespac Midstream, Fortress Energy and EIG.

Developer prequalification

The long list of potential developers for this opportunity should be screened down to 6-10 qualified bidders. Screening could be based on the following criteria: LNG supply portfolio, previous relevant experience of developing an LNG import terminal, access to LNG shipping, evidence of financial resources sufficient to implement the project and evidence of a competent project development team able to execute the project. The screening activity could also adopt an Expression of Interest process to further inform potential LNG developers/suppliers about the project and obtain preliminary information on their capabilities and interest.

Request for Proposals preparation

The Government entity in charge of the process to select an LNG terminal developer/gas supplier will need to prepare a Request for Proposals (RFP) document that will provide the data required for a bidder to produce a price that is as firm as possible. All available data on the project should be provided under confidentiality to the shortlisted bidders.

The RFP would be comprehensive and would take some months to prepare. A typical RFP document would cover the following areas:

- An introduction on the RFP process and the entity conducting the process
- A description of the project
- A description of the precise services required e.g. LNG supply, development and operation of an LNG terminal, supply of gas to end users
- A description of the RFP process and instructions to proponents including subjects such as the RFP schedule, communication, RFP clarification, form of proposals, validity of proposals, clarification of proposals, etc
- A timeline for the RFP
- A description of the proposal evaluation process
- A description of the short-listing and selection process.

A form of BOO agreement and a GSA would be included as attachments to the RFP. These documents could be draft agreements or more likely term sheets outlining the essential terms of the agreements to be developed.

The Government entity in charge of the process would need to engage specialist advisers, LNG commercial and technical as well as legal, to assist in preparing the RFP, conducting subsequent negotiations and finalising agreements.

RFP process

Once the RFP is prepared an RFP process will be followed and will include at least the steps below:

- Issue RFP to shortlisted companies and confirm receipt
- Respond to clarifications requests from proponents
- Site visits
- Receipt of proposals
- Review proposals
- Clarify proposals
- Final bid evaluation

- Government review
- Negotiations with preferred bidder or bidders
- Execution of agreements.

A schedule for the RFP process is included in the Schedule section below but experience indicates that it will take about 6 months to prepare for the RFP process and about 12 months to execute the process.

Developer selection and evaluation criteria

In selecting a terminal developer/gas supplier Mauritius should select the lowest price offer for the supply of energy subject to technical standards being met. General technical evaluation criteria would include; general LNG experience and capability, quality of LNG implementation plan, project schedule, terminal performance criteria and deviations from proposed agreements. Proposals that achieve a satisfactory technical rating could then move on to the financial evaluation, which would take into account the fixed costs of providing the infrastructure and the variable cost, which is primarily the cost of LNG.

From the evaluation process the Government entity in charge of the process would be able to rank the proponents. At this stage of the process 2 or 3 proponents should be selected for further negotiations.

Negotiation and final agreement development

The Government entity in charge of the process will enter into negotiation with the preferred proponents to finalise the deal with Mauritius. The critical path to completing negotiations is likely to run through legal drafting and negotiations of the definitive agreements – a BOO agreement and a GSA. It would be normal in a gas/LNG RFP process to negotiate key commercial terms e.g. price, with the preferred proponents after they have been selected and no proponent would agree to terms of a GSA or BOO agreement without significant negotiations considering legal, commercial and operational aspects of the agreements.

10.6.2.5 Project schedules

The overall schedule for an LNG import terminal project is estimated to be a 50 month period between the Government deciding to proceed with a project and the start of operations.

This schedule is based on an FSU concept, where an LNG ship can be acquired and converted to an FSU in an estimated 16 months. Development options with an onshore storage tank would be expected to take significantly longer. The critical path for the project would switch from the jetty to the storage tank which is estimated to take around 36 months to construct.

10.6.3 Financing

Financing for the LNG terminal project would be a task for the terminal developer but general principles for financing an LNG project are discussed. In summary, there are a number of sources of financing available that make project financing feasible.

10.6.3.1 Development phase financing

The first phase of a project is the development phase. For a project such as Mauritius a budget of $15 million should be sufficient to develop the project. This phase of the project is not normally financed as it is too high risk. If Mauritius follows the strategy suggested, then the majority of the costs at this stage will be carried by the developer selected. The costs to be carried by the Mauritius Government once the developer is selected will be restricted to facilitation and legal drafting and negotiation of the interfaces with the Government.

10.6.3.2 EPC phase financing

Financing during the EPC Phase will be the responsibility of the terminal developer (owner of the facility). The responsibility with the Government for financing will be whatever is negotiated in the agreement with the Developer. This is likely to include: purchase of land that will be leased to the project, purchase of rights of way for any gas pipeline and provision of back stop guarantees for the Government entities that will be the foundation customers for gas.

It will be up to the Developer on how they finance the project. The following information is provided as an illustration on how this may be achieved and some of the potential sources for financing.

If an FSU is chosen as the preferred option, then the vessel is likely to be chartered. Ships are attractive to banks to finance as they are often chartered on a long-term basis providing assured cash flow to the bank and they are easy to seize and charter out in the event of a default. For this reason, ships can be highly leveraged and financial terms can be attractive.

International Financial Institutions (IFIs)

At least three IFIs should be willing to consider financing the infrastructure for an LNG import project in Mauritius provided that the project clearly shows both sound economics and a move away from coal and heavy fuel oil. These are: International Finance Corporation (World Bank), African Development Bank, and Trade and Development Bank.

The advantage of these organisations is that they are more willing to lend to Africa and accept higher risks. The disadvantage is that their lending must satisfy politically determined criteria as well as financial criteria. Their processes to satisfy these political criteria and the higher standards of public consultation required does increase the time required to gain approval for a loan. Typically, these institutions will need to engage consultants to review the project for technical, economic and environmental due diligence. The bid and contract cycles for this process may take a year. They will also require public consultation periods before they can make a loan commitment, and this typically takes three to six months. Although almost all the other banks now subscribe to the World Bank's Equator Principles (standards for environmental due diligence), the reality is that the IFIs are still more rigorous and sensitive in their public consultation processes than commercial banks.

Export Credit and bilateral loans

The traditional source of finance for oil and gas projects is export credit and to a lesser extent bilateral loans. Export credits are loans made available to finance the purchase of equipment or services from country A by country B. Some countries, and particularly Japan, will also offer export credits to finance projects that would deliver products to Japan, such as LNG. Export credits are guaranteed by the government of the supplier's country or by an institution or company established for this purpose. This guarantee is paid for through a fee that must be paid when the loan is committed.

The appetite of a particular export credit agency depends on its risk evaluation and its existing portfolio of loans. Not all agencies place their policies in the public domain but, for example, the UK Export Finance currently states that Mauritius is a Consensus Category 2 country, they have an appetite for Pounds Sterling 2 to 3 billion and they are open to lending on short and long-term basis. UKEF also have online information on the insurance premium required and the indicative fee for Mauritius, which is rated as a Category 3 country, for a loan drawn down over 3 years and repaid over 7 years the premium is 3.57%. A well formulated project may improve on this level of insurance cost. The interest rate on an export credit loan is set by the OECD Consensus rates and are intended for countries such as Mauritius to reflect the cost of a competitive bank loan. The rate published for US Dollar loans for the last two weeks of June is 3.93% for loans greater than 8.5 years duration. Rates are published for most major currencies.

Conventionally, export credits only cover up to 85% of the value of the goods or services. Some export credit agencies will also finance a percentage of local construction costs. The balance must be funded by equity.

Mauritius banks

Mauritian registered banks are familiar with lending for hotels, power plants and renewable energy projects but for banks in Mauritius lending to an LNG project would be new and they may find it difficult to evaluate the risks. Among the foreign banks listed in Mauritius, several of them have teams devoted to energy projects and have financed LNG projects. We therefore believe that loans from these foreign banks registered in Mauritius for an LNG project should be feasible as they can draw on their sector specific project experience. An interest rate of 5.5% to 6.5% should be feasible. Borrowing to cover the Mauritian Rupee denominated local construction costs could be covered this way.

Alternative credit mechanisms

The conversion to LNG will have a significant impact on greenhouse gas emissions. The total CO_2 emissions by Mauritius will be significantly reduced by the project. If this reduction is not committed by the government for other purposes, then there are programs where this can be used by another country.

The Clean Development Mechanism (CDM) is described as: "the CDM allows emission-reduction projects in developing countries to earn certified emission reduction (CER) credits, each equivalent to one tonne of CO2. These CERs can be traded and sold and used by industrialized countries to a meet a part of their emission reduction targets under the Kyoto Protocol." (https://cdm.unfccc.int/about/index.html)

Projects have gained grants and soft financing using this mechanism. It would require some work to identify a counterpart who needs to reduce their CO_2 emissions and who is willing to take this route to achieving reductions.

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