CHAPTER 2

PROJECT DESCRIPTION
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2 PROJECT DESCRIPTION (PREFERRED ALTERNATIVE)

2.1 INTRODUCTION

The proposed Quantum project is expected to install commission and operate the infrastructure to import, store, re-gasify Liquefied Natural Gas (LNG) and deliver re-gasified LNG to off-takers in Tema area for an initial period of ten (10) years. The project is expected to have the following components;

- Floating Storage and Re-gasification Unit (FSRU)
- Offshore Mooring and Support for Floating Units
- Primary Support Facilities and Systems
- 16 inch Flexible Riser
- Pipeline End Manifold Structure
- 24 inch Subsea Pipeline, Tie – in Spool and Landfall
- Onshore Reception and Metering Facilities
- Gas Distribution Pipelines

This section of the report presents the stage-by-stage description of the proposed project components, activities and logistics. It is proposed that activities for the Tema LNG project shall be carried out in different stages i.e. Construction; Testing and Pre-commissioning; Operation and Maintenance; and Decommissioning. Description of the various project components is provided in the subsequent sections.

2.2 PROJECT OVERVIEW

The Tema LNG Import Terminal is being developed to supply natural gas to the Tema region in Ghana. Four power stations have been identified for the receipt of gas in the initial phase of the development (Sunon Asogli, VRA Kpone Thermal Plant, CEN Power and CENIT Energy) with potential for expansion to further end users in the future.

The development comprises a Floating Storage and Regasification Unit (FSRU), permanently moored offshore Ghana, which receives LNG which is then regasified and then exported via a 16” riser, Pipeline End Manifold (PLEM) and 24” pipeline to an onshore metering and distribution terminal.

From the onshore terminal the gas is supplied to each of the end users via an onshore pipeline network constructed of up to 20” diameter pipe. There is a metering skid at each of the end users to enable fiscal metering of the gas supply.

The system is designed for 750 Million Standard Cubic Feet per Day (MMscfd) peak throughput for short periods; however, the FSRU initially deployed will have a maximum steady state throughput capacity of 500 MMscfd. In the event of increasing demand such that the 500 MMscfd capacity of the initial vessel is inadequate, a replacement larger capacity FSRU will be mobilized. In addition, to enable capacity of greater than 750 MMscfd a second riser will be required.

Figure 2-1 illustrates the Tema LNG Import Terminal Field Schematic.
Figure 2-1: Tema LNG Import Terminal Field Schematic
2.3 PROJECT LOCATION AND GEOGRAPHICAL SETTING

The geographical setting for the proposed Tema LNG project is within the heavy industrial enclave of Tema, in the Greater Accra Region as shown in Figure 2-2. The area is mainly zoned by the Town and Country Planning Department (TCPD) for large industrial activities. In close proximity to this proposed LNG project is the West Africa Gas Pipeline (WAGP) project.

The proposed development will have network distribution pipes across onshore land use areas and supply gas to five (5) Identified Independent Power Plant stations. This development will have other facilities and services across two (2) administrative districts of the Greater Accra Region i.e. Ningo Prampram District Assembly and Kpone Katamanso District Assembly. Environmental and Socio-economic characteristics of the various project locations are described in Chapters 8 to 10 of this ESIA report.

2.3.1 Site Description

The landfall site is located approximately 2.5km northeast of Tema new town and approximately 10 km southeast of Prampram. Sandy beaches constitute about 70 percent of the coastline in Ghana; the sediments along the coastline are redistributed primarily by an eastward alongshore current in the form of littoral drifts and less importantly by tidal currents.

2.3.1.1 Terrain/Geology

The terrain and geology at the landfall area will impact on cost and schedule owing to the potential rock volumes to be excavated in the beach and nearshore area where trenching is necessary for pipeline stability and protection.

At this stage geotechnical survey assessments are yet to be undertaken, hence the extent of lower lying rock cannot be confirmed. The WAGP EIA report indicates that the Tema nearshore zone is characterized by medium- to high-energy intertidal rocky platforms with extensive algal growth and diverse fauna. Where the pipeline transition from the beach to onshore, the pipeline route and metering station is located on tilted, acidic gneiss rocks. The nearshore sediment is sandy, while the offshore is more of a sandy-mud.

2.3.1.2 Topography and Bathymetry

The beach to landfall area is relatively flat, with a maximum slope elevation of 5%. The nearshore area is also very shallow, Salt pond to Tema Admiralty charts and WAGP Tema as-built alignments points to only a meter drop in sea bed profile up to 650m offshore after which the sea bed profile changes to a meter drop every 65m (approx.) up to 900m offshore (see Figure 2-3). This means a shallow draft vessel for landfall installation may potentially be required to anchor at least 1km offshore where the water depth would be approximately 5m should this option be utilised.

A detailed topographical survey of the landfall and nearshore bathymetry is still required to determine the current conditions of the coast and seabed prior to any construction activities. Once this information is available, an estimate for earthworks and refinement of costs for the landfall construction can be made.
Figure 2-2: General Arrangement of Project Infrastructure
2.3.2 Offshore Location

The 20km² study area is located approximately 6km south west of Tema Port (as shown in Figure 2-3). QPRGG appointed INTECSEA (Worley Parsons) to perform a metocean study for four potential locations for the LNG terminal / mooring, of which two were selected for additional analysis (Refer to Chapter 4). The water depth ranges between approximately 20 m and 40 m.

As a part of the INTECSEA study (INTECSEA, 2014) a preliminary (Stage 1) uptime assessment was conducted to understand the implication of the metocean conditions on the facility functional viability. Two other points were also analysed, but were excluded from further analysis.

Further location assessment revealed three route options as described in Chapter 4 (Project Alternatives), of which option 1 is selected as the base case for front end engineering design (FEED). The FSRU is located on the east side of the WAGP and within the fishing and shipping exclusion zone (see Figure 2-2). The riser hang off is on the east of the FSRU and the PLEM is located on the same side on seabed. The import pipeline is routed north towards the boundary of exclusion zone corridor where it is routed outside of the exclusion zone to avoid the mooring anchor exclusion zone. A total of 525m length of import pipeline falls outside the exclusion zone and extends out of exclusion zone by 43m. The pipeline route maintains a minimum 50 m separation between WAGP pipeline from about 1 km to landfall tie-in which is required to be trenched and backfilled. Detailed offshore route description is provided in section 2.4.8.2.

2.4 LNG PROJECT COMPONENTS AND SITE LAYOUT

2.4.1 Floating Storage and Regasification Unit (FSRU)

The FSRU for the Tema LNG Project, known as “Golar Tundra” would be supplied by Golar and built by Samsung Heavy Industries Company Limited. It would resemble a marine vessel, both in appearance and design, and would remain moored in place for the duration of the Project. It would be approximately 295 m overall length and 44 m wide with a draft of 12.3 m at summer freeboard (extreme). The FSRU would not be self-propelled but would be equipped with a pair of stern thrusters to assist when required to maintain a constant heading during mooring operations with LNG carriers.
The main deck of the FSRU would be approximately 14m above the water line, with a “trunk deck” extending about 10m above the main deck to support some of the process equipment. Figure 2-4 depicts the layout of the primary equipment on the FSRU. LNG storage tanks would be located below the decks and would not be visible. To enhance physical protection of the LNG storage area, the FSRU would be double-hulled on all sides in a manner similar to LNG carriers.

The FSRU would be designed to accommodate storage of up to approximately 170,000 m$^3$ of LNG, equivalent to 100 million cubic meters of natural gas. It will have an initial send-out rate capability of 250MMscfd (29,497 m$^3$/h) (able to supply approx. 1250 MW of combined cycle capacity) with ability to deliver up to a peak throughput of 750MMscfd (88,490 m$^3$/h).

The terminal will have a re-gasification system to “vaporise” the LNG and send it as natural gas to the coast. The LNG re-gasification will be carried out in heat exchangers mounted on the terminal, using sea water as a heating medium. LNG would be delivered in LNG carriers with cargo capacities ranging from 125,000 to 145,000 m$^3$. The LNG will be delivered into the FSRU from a delivery carrier approximately every two weeks and steadily re-gasified.

The FSRU will be permanently held in position on a spread mooring and connected to a 24 inch subsea pipeline via a flexible riser pipe. A single carrier berth would be on the starboard side of the FSRU, along with unloading arms and other LNG unloading equipment and facilities. Living quarters to accommodate a minimum of about 20 officers and about 30 crew members would be included on the aft end (stem or rear) of the FSRU.

Design and material specifications for the FSRU have been determined in consultation with a ship classification society, Det Norske Veritas (DNV). Classification societies are organisations that develop and apply design, construction and maintenance rules for ships and offshore structures based on opinions of industry experts. These rules apply to the strength and integrity of a vessel or the structure’s hull and appendages, and the reliability of steering, power generation and other systems needed to maintain essential services. Details of the FSRU design and specifications are presented in Annexure A.
Figure 2-4: Proposed FSRU Conceptual Design
2.4.1.1 *LNG Storage and Containment*

The double hull of the FSRU (on the bottom, the sides and the deck above the cargo containment system) would effectively provide double-walled containment around the entire LNG storage system (see Figure 2-5). Each storage tank would be separated by cofferdams from adjacent storage tanks and from spaces fore and aft of the cargo region.

Eight thermally insulated LNG storage tanks would maintain the stored LNG at a temperature of 256°F (-160°C) and at or near atmospheric pressure. Each storage tank would be equipped with a retractable pump that would be used to transfer LNG to the vaporizer system.

Golar proposes to use a design similar to the Gaz Transport, Technigaz Mark III, or Technigaz No. 96 membrane tank systems. Each of these LNG storage designs consists of the following three layers:

- A 1.2-millimeter-thick stainless steel primary barrier constructed of chromium nickel stainless steel with very low carbon content; the primary barrier would be corrugated to allow for expansion and contraction associated with heat changes;
- Polyurethane foam insulation with reinforcing glass fibers between two sheets of plywood; and
- A secondary barrier comprised of laminated glass cloth and aluminum foil, designed to contain LNG in case of leakage through the primary barrier.

All materials, material testing procedures, and selection of manufacturers for all components of the LNG containment system would be in accordance with the classification society rules.

![Figure 2-5: Generic Membrane Tank](image)

2.4.1.2 *Regasification Unit*

When the consumer demands the gas, the LNG has to be processed back into its gaseous state and transported by pipeline to its desired location. The FRSU will vaporize the LNG for subsequent shipment to the coast as natural gas through the re-gasification units.

The main components of the regasification unit are listed below:

- Sea water pumps which are used to pump seawater to the vaporizers.
- Vaporizers warm up the LNG so that it can be transformed back to its natural gaseous state.
- Booster pumps pump the LNG under high pressure into the vaporizers
- Boil of Gas (BOG) compressors, compresses gas that boils off (resulting in vaporization of the LNG). This compressed boil-off gas is typically added to the natural gas send-out. It may also be re-liquefied and returned to the LNG storage tanks.

LNG is sent from the tanks to the regasification unit situated in front (see Figure 2-6). The regasification unit essentially comprises booster pumps and steam heated vaporizers. The booster pumps will increase the pressure, before the high pressure LNG is vaporized after which the gas is sent to the subsea pipeline via jumpers and flexible risers.

![Regasification Unit](image)

**Figure 2-6: Regasification unit on the FSRU**

In the vaporisation units, heat needs to be added to the LNG so that it can change to its gaseous state. Since the FSRU are located on sea, seawater is available in unlimited quantities compared to other sources of heat, and is therefore the preferred heat source.

Open-loop water-based systems are typically used as the heating medium where warm water is available in sufficient amounts throughout the year. Detailed description of the regasification process is presented in section 2.7.3.1.

### 2.4.2 Offshore Mooring and Support for Floating Units

The FSRU will be spread-moored and the LNG carrier will berth alongside for the LNG transfer via ship-to-ship transfer. The platform would be designed for long-term mooring of an FSRU and for receipt of LNG carriers ranging in size from 125,000 to 145,000 m$^3$.

The FSRU will be permanently held in position on a spread mooring and connected to a 24 inch subsea pipeline via a flexible riser pipe. The spread mooring chains or wires will be anchored to the seabed either using conventional anchors or more specialist systems if the ground conditions require this.

LNG cargo would be transferred from the LNG carrier via ship to ship transfer, with conventional LNG carriers berthing against the FSRU. Figure 2-7 and Figure 2-8 show a model diagram and schematic drawing of the facilities respectively.

Specific components of the proposed offshore mooring platform include:
The spread mooring systems are oriented to be aligned with the swell (i.e. N to S orientation) with the FSRU/LNG carriers (LNGC) bows towards the South;
berthing fenders and mooring and breasting dolphins at berth;
LNG loading arms, LNG drain tanks, and LNG piping between the LNG loading arms to facilitate transfer of LNG between vessels;
high-pressure gas loading arms to connect to the FSRU and facilitate natural gas discharge to the send-out pipeline;
utility platforms providing docking facilities for lifeboats and service vessels, control and switch gear rooms, utility equipment, personnel access/egress, and laydown and work areas; and
utility systems, including process support systems, electrical systems, safety systems, gas- and diesel-fuelled electricity generators, nitrogen generators, electric seawater pumps, diesel fire pumps, diesel storage tanks, lubrication oil storage tanks, potable water and waste water tanks, sewage treatment unit, and fire water monitors.

2.4.2.1 Berthing and Unloading Facilities

Berthing operations are limited by different environmental conditions depending on whether specialised or standard tugs are used. Specialised tugs are designed with an enhanced hull shape and equipment allowing operations in higher sea states but at considerably higher cost.

The planning of tug requirements for berthing operations needs careful consideration of the forecasted metocean conditions and berthing method. Tug requirements for side by side offloading are as follows:

- Two standard tugs in push berthing operations, <1.5 m Hs (wave height)
- Four standard tugs in pull berthing operations (working on long towlines), < 2.0 - 2.2 m Hs
- Four specialised tugs in pull berthing operations (working on long towlines), < 2.5 - 2.9 m Hs

LNG carriers would berth along the starboard side of the FSRU; only one LNG carrier would be allowed to berth at a time. Each LNG carrier would be secured to the FSRU using mooring lines equipped with quick-release hooks that would be permanently attached to the FSRU. Floating pneumatic fenders would be used to separate and prevent contact between the hull of a moored vessel and the side of the FSRU while the vessel is berthed at the FSRU.

The unloading area the carrier berth would support the primary equipment needed to safely unload LNG, including four LNG loading and vapour return arms; loading arm power packs and controls; LNG and vapour transfer piping and manifolds; gas and fire detection, fire protection, and fire fighting facilities; life-saving equipment; telecommunications equipment; an access gangway; and a small crane.

LNG loading and vapour return arms would be 16-inch-diameter fixed structures attached along the starboard side of the FSRU approximately midship, with two arms serving as LNG loading lines, the third arm serving as a vapour return line, and the fourth arm serving as either a loading or vapour return line. The loading arms would be similar in design to those used at existing onshore LNG terminals, but a more flexible articulation at the point of connection with the LNG carriers would permit LNG transfer under a wider range of sea state conditions.

The portion of the hull beneath the LNG loading arms would be armoured to provide additional structural protection in the event of an LNG spill during loading. The berthing area would be equipped with protective and emergency safety systems, including emergency release mechanisms in the LNG loading arms, protective steel cladding on the FSRU in the vicinity of...
the loading arms, leak and fire detection and alarm systems, and personnel protection equipment.
Figure 2-7: Model Diagram of a Proposed Offshore Terminal

(source: Golar LNG Energy)
Figure 2-8: Schematic Drawing of the Proposed Offshore Terminal
2.4.2.2 Loading Equipment

Offloading is usually only possible under relatively benign environments since the offloading mechanism is directly subjected to the relative motions during berthing of LNGC. These motions present various risks to the offloading system, such as potential mechanical failure, fatigue failure and exceedance of operating envelope. Based on past studies undertaken by WorleyParsons, “Chiksan® Marine Loading Arms for LNG Service” appear to be the most appropriate for offloading operations from LNGCs to the FSRU at the specific site location selected. This system is already used onshore and offshore on many units and all components are industry proven. However, hose technologies such as Gutteling or Trelleborg hoses can also be considered and are workable within similar operating envelopes as loading arms, however, the hose handling increases complexity and risk to day-to-day offloading operations.

Typically, based on past project experience, LNG loading arms have a design wind velocity of 25 m/s (3 second gust) when connected.

![New connecting mechanism added to the Chiksan Marine Loading Arm](image)

**Figure 2-9: New connecting mechanism added to the Chiksan Marine Loading Arm**

2.4.2.3 Side – by – Side Transfer

Side-by-side transfer involves manoeuvring an LNG carrier alongside the FSRU, mooring the two vessels together, separated by fenders, conducting the transfer operation via connection to the LNG carrier’s midship manifold. Manoeuvring would usually involve assistance of tugs. Typical separation of the vessels is then the diameter of the fendering, usually approximately 5 m.

For the transfer of LNG, an incoming LNGC will berth along the FSRU in a side-by-side configuration, offloading the cargo by means of “hydraulic arms”. Once the LNG is re-gasified, the gas will be transferred to a transfer platform by means of “jumpers” (flexible hoses). Subsequently, from the platform, the gas will be transferred via a “riser” to a fixed seafloor pipeline to the main land.

2.4.3 Primary Support Facilities and Systems

The primary support facilities and systems on the FSRU include power generation equipment and the associated selective catalytic reduction (SCR) systems, recondensers and boil-off gas compressors, metering andodorisation equipment and systems, an emergency flare, a ballast system, utilities/seawater system, waste and water treatment systems, and crew quarters and command control facilities. Information on these systems is presented below;
2.4.3.1 Power Generation

Four sets of 38,500 kW duel fuel engine generators on the FRSU would provide power to the facility. The primary fuel for the gas turbines would be natural gas (regasified LNG that has been reduced in pressure). One of the generators would be designed to use low sulfur diesel fuel to allow use in emergency situations.

All fuel and lubricating oil tanks would be of welded steel construction and integrated into the hull. The main diesel fuel tanks would consist of two storage tanks, two service tanks, and a tank for the emergency generator. Additional small diesel tanks or drums would likely be stored on the FSRU during operation.

All fuel and lubricating oil tanks and systems would be fitted with spill containment features in accordance with the Project-specific Spill Prevention, Control and Countermeasure (SPCC) Plan. The basic safety and spill features of the design would include drip pans; quick-closing, remotely operated tank isolating valves; and heat-resistant level gauges and alarms.

2.4.3.2 Ballast System

A port and starboard ring line ballast system, servicing all ballast tanks, with branch lines to the individual tanks shall be provided. The ballast valves shall be equipped with remote control led actuators of hydraulic type. Strainers shall be installed in the suction lines from the sea chests. One sea chest shall be arranged on each side of the vessel. The ballast pumps shall have suction from sea and from all ballast tanks and discharge overboard and to ballast tanks as well as transferring from one ballast tank to another. The ballast system shall be of capacity sufficient to maintain constant draught under all LNG loading conditions. A ballast tank eductor system, using one of the fire pumps shall be fitted to each double bottom ballast tank for stripping purposes. Three electrically driven horizontal ballast pumps with automatic suction device shall be installed in their own machinery compartment. One pump shall have stand-by functions. Each pump shall have a capacity to allow both pumping and gravity flow to/from the ballast tanks from/to the sea for the double bottom water ballast tanks for the full duration of the LNG cargo to be filled. The pumps shall also provide a constant draught during FSRU loading operations. An environmentally friendly ballast treatment system shall be installed.

2.4.3.3 Utilities

Sanitary Wastewater

Sanitary wastewater would be collected and routed to a holding tank. QPGGL is proposing to treat wastewater generated on the FSRU using a membrane bioreactor system. Wastewater would be discharged only if it met both local and international water quality discharge standards (i.e. IFC). If these standards could not be met, wastewater would be containerised and sent to an approved onshore disposal site.

The LNG facility operation will generate the following wastewater disposal streams:

- Stormwater from the LNG facility site
- Sewage effluent produced by the sewage treatment plant
- Brine from the seawater desalination plant
- Potentially contaminated wastewater from the facility process areas

Effluent Treatment Plant

The effluent treatment plant will be a tertiary treatment facility designed to treat wastewater to a quality suitable for re use in amenities or discharge to the Port. The effluent treatment plant will
be established early in the construction phase of the project and will include the following components:

- Main equalisation tank and off-specification tank
- Membrane bioreactor package
- Granular activated carbon filter package
- Ultraviolet (UV) disinfection package
- Chemical dosing package
- Sludge dewatering facilities

Mixed effluent will be filtered in the membrane bioreactor plant to produce clarified effluent, which will be passed through a granular activated carbon filter for total suspended solids removal followed by UV treatment. This clean effluent will be stored prior to use as toilet flushing water and make-up water in the effluent treatment plant.

Excess sludge from the membrane bioreactor plant will be pumped to the sludge holding tank and dewatered in a centrifugal system to produce a thick sludge cake for offsite disposal as a biosolid. Sludge dewatering liquid will be diverted back to the membrane bioreactor plant for additional treatment.

**Brine Disposal**

The brine discharge will be piped and discharged into the Port via an outfall and diffuser arrangement. The brine discharge point will be at a location sufficiently far offshore to prevent the formation of stagnant hyper-saline areas in harbour waters and include the following characteristics:

- Sufficient depth for mixing to occur and an adequate distance from the shoreline and from the seawater intake
- Free flowing current conditions that would disperse the brine discharge
- Available access for maintenance purposes
- Free from vessel contact and within the LNG facility’s marine lease area.

**Storm water Handling and Pollution Prevention**

Collection, treatment and discharge of storm water would vary with location on the FSRU. Uncontaminated storm water runoff, as well as firewater system test water, would be directed overboard via scupper drains. Storm water that collects in the vicinity of equipment that could release oil or oil-like substances and other chemicals would be collected with curbs and gutters and routed to a holding tank, brought to shore, and disposed of at an approved facility in accordance with EPA Permit conditions. The likelihood that storm water would be contaminated by hazardous materials onboard the FSRU would be minimized through the use of best management practices (BMPs). BMPs would include proper containment, storage and handling of hazardous materials; regular inspections; and spill prevention practices.

**Crew Quarters**

Living quarters on the FSRU would accommodate a total of 48 officers and crew members as shown in Table 2-1. Crew members would be transported to and from the FSRU on small boats or tugs. For safety reasons, all living, dining, and recreational areas would be contained within the crew quarters and separated from all processing areas. A helideck, which would be for emergency transport only, would be located on top of the crew quarters.
Table 2-1: Number of Crew Members

<table>
<thead>
<tr>
<th>Officer/Crew</th>
<th>No. of Persons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Officers (Minimum)</td>
<td>Captain class : 2</td>
</tr>
<tr>
<td></td>
<td>Senior officer class : 4</td>
</tr>
<tr>
<td></td>
<td>Junior officer class : 13</td>
</tr>
<tr>
<td></td>
<td>Pilot : 2</td>
</tr>
<tr>
<td>Number of Crew (Minimum)</td>
<td>Petty officer class : 4</td>
</tr>
<tr>
<td></td>
<td>Rating class : 13</td>
</tr>
<tr>
<td></td>
<td>Worker (Suez Crew ) : 6</td>
</tr>
<tr>
<td></td>
<td>Worker (Riding Squad) : 4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>48 people accommodated in 40 cabins</strong></td>
</tr>
</tbody>
</table>

Command and Control Facilities

Command and control facilities would be located in a central control room in the crew quarters area. These facilities would include control and monitoring systems for LNG and natural gas processing, ballasting, communication, radar equipment, electrical generation, emergency systems, and thruster controls.

2.4.4 16 Inch Flexible Riser

2.4.4.1 General

A 16 inch flexible riser is required for the export of gas from the FSRU to the subsea PLEM. The riser shall be in accordance with GS ISO 13628-2 and project documents.

2.4.4.2 Functional Requirements

The riser shall meet the following functional requirements as a minimum:

- Meet acceptable erosion limits for the given design capacity of the riser (500 MMscfd);
- Suitable for diver assisted installation and intervention;
- Include a means by which the carcass may be safely vented at the FSRU;
- Be suitable for installation using common construction techniques and vessels.

2.4.5 Pipeline End Manifold (PLEM) Structure

2.4.5.1 General

The field layout in the FEED study consists of one PLEM structure. The PLEM structure consists of piping, valves, a Subsea Isolation Valve (SSIV) and control equipment for the operation of the SSIV. The structure is designed to be installed with one single lift operation. The height of the structure is driven by the height of the equipment inside, including a minimum clearance of 300 mm between the protecting roof member and the top of the equipment.

The PLEM is to be located inside the exclusion zone and therefore the structure is not designed for trawl interaction. The foundation concept is based on a gravity foundation using mudmats. Should the structure location be outside the exclusion zone, structural foundation and protection design need to accommodate all requirements for that location.
2.4.5.2 Model Description

The structure consists of main members forming a base frame, 10 m long x 6.5 m wide on the beam centres. The foundation is two skirtless mudmats with base frame members acting as its stiffeners. Skirtless mudmat is assumed because there is no fishing activity considered.

Tubular columns and tubular top beams create a protection structure with a close space tubular roof for dropped object protection. The roof is made removable so that the SSIV, valves, actuators and other equipment could be easily accessed for retrieval and reinstallation.

The piping configuration consists of a 24-in header with two ball valves (one SSIV) and two 16-in branches. The structure provides support and protection for all the piping components, valves and other equipment. The components are all located within the structure envelope and are nominally supported at the base frame (see Figure 2-10).

![Figure 2-10: PLEM Typical Layout – SACS 3D View](image)

2.4.6 24 Inch Subsea Pipeline, Tie-In Spool & Landfall

2.4.6.1 General

The subsea system includes a 24 inch subsea pipeline and tie-in spool (at the PLEM) for transporting gas from the PLEM to the onshore terminal. The pipeline shall be in accordance with GS ISO 13623: 2009, Petroleum and Natural Gas Industries – Pipeline Transportation System.

2.4.6.2 Functional Requirements

The pipeline and tie-in spool shall meet the following functional requirements:

- The pipeline and tie-in spool shall be designed according to specific temperatures, pressures, fluid and flow rate as defined within the Basis of Design and Flow Assurance Report (Genesis, 2014);
- The pipeline and tie-in spool will be constructed of carbon steel as detailed within the Material Selection and Corrosion Prevention Report (Genesis, 2014).
• Connection of the pipeline and tie-in spool shall be by means of diver installed flange connections;
• The pipeline and tie-in spool shall allow for intelligent pigging.

2.4.7 Onshore Reception and Metering Facilities

The onshore reception/metering facilities are designed to receive the gas from the FSRU via subsea pipeline. The terminal will receive electrical power from the National Grid but will also include a backup generator. The design of the onshore reception facilities shall take into account the highly saline atmosphere, which shall be reflected in selection of materials, coatings, etc.

The subsea pipeline terminates at an Onshore Reception Facility where a temporary pig receiver may be connected to allow for periodic inspections of the subsea pipeline. An emergency shutdown valve (ESDV) is provided upstream of the pig receiver to allow the onshore reception facility to be isolated from the pipeline. A manual connection to the reception facility flare has been provided upstream of this ESDV to enable manual depressurisation of the subsea pipeline at the reception facility.

Gas will pass through filters which are fitted with differential pressure transmitters. These allow the condition of the filters to be monitored. Under normal operation no contaminants are expected, however during initial start-up, corrosion and debris related to the construction may accumulate in these filters.

The gas passes through a forward pressure control valve, where the pressure is regulated to meet the desired onshore pipeline operating pressure (set to ensure design flow to each end user). Under normal conditions this valve is expected to be fully open, and perform minimal control action as primary pipeline pressure control should be performed at the FSRU.

The gas then flows through the Fiscal Metering Package, where the flow rate is measured by 3 x 50% ultrasonic flow meters. Temperature, pressure and density measurements are also made to correct for fluctuations in these parameters thereby ensuring accurate measurement. Dual redundant water dew point and gas chromatographs analysers are provided to confirm that the gas is meeting the required specifications.

The gas is then routed to the onshore distribution network. An additional shutdown valve is provided to isolate the reception facility from the onshore distribution network.

The onshore reception facilities will incorporate the following;

• Inlet and pressure letdown facilities;
• Metering system including gas analysis;
• Metering system located in a logical equipment room;
• Back-up diesel generator;
• Battery back-up system;
• Analyser house;
• Manual vent system;
• Communication system.

The onshore metering facilities will meter the gas arriving onshore from the FSRU. The gas analysis will confirm the specification of the gas is acceptable for onward transmission to the gas users. Individual dedicated metering systems will be located at the boundary fence of each gas user.
Figure 2-11: Plot Plan Subsea Pipeline Onshore Reception and Metering Facility
2.4.8 Gas Distribution Pipeline Layout and Route Description

2.4.8.1 Routing Restrictions

The import pipeline is to be routed inside the existing fishing and anchor exclusion zone which was allotted for the existing WAGP pipeline. The exclusion zone is about 1 nautical mile wide to the east of the WAGP pipeline and Quantum has a strong preference not to seek approval for extension to the zone.

Due to the onshore routing constraints, the import pipeline landfall location is required to be to the east of existing WAGP pipeline landfall location. In addition to the above, the following restrictions constrain the routing of the Gas Import Pipeline:

- FSRU orientation is fixed as bow to south facing the sea and the riser hang off on the right side.
- A lay radius of 800 m is used for the import pipeline routing from the FSRU location to the landfall.
- A minimum of 200 m of straight pipe is required before any change in route curvature.
- Anchor chains from FSRU are 900 m long and reach within close proximity of the edge of exclusion zone corridor on stern side of FSRU and are also in close proximity of WAGP pipeline on bow side of FSRU.\(^1\)
- A 50 m exclusion zone is assumed around the anchor chain at seabed.
- A 500 m exclusion zone is assumed around existing Single Point Mooring (SPM).
- A minimum separation of 50 m from existing WAGP pipeline.

2.4.8.2 Offshore Pipeline Route Description

Using the design data and the routing restrictions stated in section 2.4.8.1, three route options were considered (refer to Chapter 4: Project Alternatives) with Option 1 selected as a base case at the FEED stage.

The pipeline will be laid between the existing West African Gas Pipeline (WAGP) and the existing pipeline through which oil offloaded at the Single Buoy Mooring (SBM) is transferred to shore. This option considers the FSRU, which will be spread-moored, to be located inside the existing Maritime exclusion zone on the east side of the WAGP pipeline. PLEM is located on the eastside of the FSRU; a tie-in spool approximately 100m in length connects the PLEM to the import pipeline.

From the spool tie-in (KP 0) the import pipeline routes north towards the corridor of exclusion zone which extends for 1 nautical mile on either side of the existing WAGP. The FSRU mooring anchors are located near the exclusion zone having a minimum of 50m exclusion zone at each anchor location. To avoid crossing the exclusion zone around anchors the import pipeline is routed outside the fishing and anchoring exclusion zone before routing back inside the corridor. A pipeline lay radius of 800m is considered while routing which will allow minimum pipeline outside the exclusion zone. A total of 525m length of import pipeline falls outside the exclusion zone and extends out of the exclusion zone by 43m.

The import pipeline, once inside the exclusion zone, routes north-west towards the WAGP pipeline. At approximately KP 5.6 it curves around the existing SPM exclusion zone to align for landfall tie-in point. The pipeline route maintains a minimum 50m separation between WAGP

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\(^1\)Note that the final position of FSRU may require anchors to be rotated by up to 11.25° clockwise
pipeline from approximately KP 10 to landfall tie-in section which is required to be trenched and backfilled.
Figure 2-12: Offshore Pipeline Location Map
2.4.8.3 Nearshore – Landfall Route Description

The proposed pipeline shall run parallel to the existing WAGP from the nearshore zone before transitioning onshore. There is sufficient space (80m X 75m) east of the proposed pipeline to serve as a construction equipment laydown area. It is important that the selected laydown area should be above highest astronomical tide (HAT).

Figure 2-13: Footpath Access to Beach Area

The area intended for equipment laydown is predominantly made up of rock and shale material and as a result will need to be graded and prepared before it can be used. The proposed laydown area shall be fenced and bunded for security and environmental contamination prevention purposes respectively. The view of the beach area east and west of the proposed pipeline is presented in Figure 2-14 and Figure 2-15.

Figure 2-14: East facing View of Beach Area
2.4.8.4 **Onshore Pipeline Route Description**

**Landfall to Proposed Metering Station**

This section of pipeline is within the Tema industrial area, and there are a relatively small number of buildings and other activities likely to adversely impact the QPGGL pipeline. There are currently no established roads, only tracks, and there are no pipeline crossings or significant cable crossings.

![Figure 2-15: West facing View of Beach Area](image)

![Figure 2-16: Landfall – Onshore Transition Overview towards Metering Station](image)

From the landfall area the proposed pipeline transitions onshore and runs almost parallel to the existing WAGP towards the WAGP and Volta River Authority (VRA) metering stations. The pipeline between landfall and the onshore Metering Station is approximately 710 m in length.
The Landfall Site Visit Report by Genesis suggests that there is limited flexibility for the exact location of the landfall because of nearby rock formations, and it is likely therefore that the landfall will be relatively close to the landfall of the existing WAGP.

A minimum separation of 15m centre to centre to the WAGP has been adopted for the onshore routing of the proposed QPGGL pipeline. Several WAGP marker points were identified giving a reference point for maintaining the required separation distance.

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2 Proposed Pipeline is on the east side of existing building in figure above
3 WAGP is west of existing building
Gas from the Metering Station will be routed into a distribution manifold, from which dedicated pipelines will route gas to each end user. The delivery point at each end user includes a fiscal metering skid.

Two main distribution routes, east and west, have been reviewed during a preliminary site visit undertaken by a Pipeline Engineer. These routes pass through more populated and industrialised areas than the pipeline from the landfall to the Metering Station, though population is still relatively sparse (refer to Figure 2-20).

The west route runs parallel to the VRA pipeline for much of its length, and includes crossings of pipelines, roads, electricity cables and a canal. This segment includes the distribution pipeline from the metering station to the GRIDCO substation along the Aflao main road. It covers a distance of less than 3km and is a heavy industrial area housing some bulk oil companies.

Pipeline route for western segment B (refer to Figure 2-19) covers the distribution channel behind the golf course opposite the GRIDCO substation along the Tema – Aflao road. It covers a distance of about 5km and runs through the Right of Way (RoW) for VRA. A few agricultural activities have been identified in the northern section of the RoW servitude.

From the metering station, the eastern segment distribution pipeline runs onshore adjacent CHASE Petroleum storage facilities to the Sunon Asogli and CEN Power facility areas. The route has similar obstacles to negotiate, but includes a river crossing which is bordered by mangroves and also crosses an overhead pylon-supported cable route. Various construction techniques have been proposed in Annexure A (Project design details and drawings) for watercourse and road crossing of pipelines.
Figure 2-19: Onshore Distribution Network and IPPs
Figure 2-20: Map showing Industrial Areas and Pipeline Routes
2.5 PROJECT CONSTRUCTION PHASE

The proposed LNG terminal and natural gas pipeline would be designed and constructed in accordance with safety standards that are intended to ensure adequate protection for the public and to prevent LNG and natural gas pipeline accidents or failures. The FSRU and proposed pipelines would be constructed in accordance to specific standards and regulations applicable. During final design, the EPC (Engineering, Procurement and Construction) contractor would prepare an Erosion and Sedimentation Control Plan specific to the Project that would be used during construction of the pipeline. Specific processes and activities to be carried out during the construction phase of the Tema LNG project are described below.

2.5.1 Site Preparation Activities

The overall approach to construction of the LNG terminal and distribution facilities is to minimize impacts to the environment and disruption to local communities. It is anticipated that construction activities will commence within the third Quarter (Q3) of 2015 with a start-up in 2016.

All construction equipment that will be transported to the site will be within the posted weight limits of the roadway system to minimize impacts to existing roadways and disruption of local traffic patterns. The majority of construction equipment used to construct the marine facilities will be delivered by barge as part of the marine fleet. Initial activities will include the mobilization of the initial resources and the preparation of the site for the subsequent construction activities that will take place. The start of construction work will consist of levelling the site by balancing the amount of cutting and filling required to reach the final grade elevations and the access roads to the project area. Other activities will include the installation of temporary facilities (i.e. fencing, parking, construction offices, staging areas, construction camp, laydown areas, equipment maintenance and fuel storage).

2.5.1.1 Construction Schedule

Anticipated commencement and completion dates for the various packages of construction are given in Table 2-2 below. It should however be noted that these are preliminary and shall be highly dependent on the overall Project and other influential factors such as approvals, and resource availability for example. Included within this are:

- temporary facilities (including the construction camp);
- all site preparation works;
- feed gas pipeline (offshore and onshore);
- all marine works for FSRU and associated equipment; and
- administration and maintenance buildings

<table>
<thead>
<tr>
<th>Activity</th>
<th>Anticipated Commencement</th>
<th>Anticipated Completion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temporary Facilities Installation</td>
<td>Q3 2015</td>
<td>Q4 2015</td>
</tr>
<tr>
<td>Civil Works</td>
<td>Q4 2015</td>
<td>Q2 2016</td>
</tr>
<tr>
<td>Piping and Steel Erection</td>
<td>Q1 2016</td>
<td>Q2 2016</td>
</tr>
<tr>
<td>Equipment Installation</td>
<td>Q1 2016</td>
<td>Q2 2016</td>
</tr>
</tbody>
</table>
2.5.1.2 *Earth Moving Activities and Temporary Works*

Mobilisation of the site preparation contractor will begin immediately after contract award and approval of the ESIA.

The site cut and fill activities will be accomplished using front-end loaders, backhoe, rippers, shovels, dozers, motor graders, rollers, water trucks and dump trucks for hauling spoils. Excavated cut material will be used for fill where suitable and the surplus deposited within the site. Water will be used for road bases and in building areas of structural fill to optimize compaction. Dust control will be maintained by the use of water spray application. All concrete will be mixed on-site using a concrete batching plant and delivered by transit mixer trucks to the foundations.

2.5.1.3 *Temporary Construction Camp*

The construction Contractor will install a temporary camp and facilities on the site to house Contractors’ personnel, subcontractor’s personnel and other personnel as required. The Contractor is expected to provide housing for the entire labour force, with an option of allowing the labour force from the adjacent communities to live at home and travel by bus to the site each workday. Additional temporary facilities will be installed to support construction such as craft training centre, material storage warehouses, workshops, fabrication shops and field offices. All temporary facilities will be self-sufficient and provide for its own power from diesel generators, water treatment and sewage collection and treatment.

2.5.1.4 *Construction Workforce*

The construction workforce is expected to peak at approximately 600 people. The majority of manpower and skills required to construct the Tema LNG Import Facility can be supplied from within Ghana. The contractor and some specialty subcontractors will bring existing key staff to Ghana from other worldwide locations to plan, organize, train and manage their work. Ghanaian nationals will be the source of a very large percentage of the remaining jobs. A list of craft categories needed for the construction activities are presented in Table 2-3.

### Table 2-3: List of craft categories

<table>
<thead>
<tr>
<th>CRAFT CATEGORIES</th>
<th>PEAK LEVEL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labourers, semi-skilled</td>
<td>150</td>
</tr>
<tr>
<td>Carpenters</td>
<td>30</td>
</tr>
<tr>
<td>Iron workers (Structural &amp; Rebar)</td>
<td>30</td>
</tr>
<tr>
<td>Cement Masons</td>
<td>20</td>
</tr>
<tr>
<td>Electricians/Instrument, helpers</td>
<td>25</td>
</tr>
<tr>
<td>Millwrights, Mechanics</td>
<td>20</td>
</tr>
<tr>
<td>Tank Fabricators</td>
<td>10</td>
</tr>
<tr>
<td>Pipe fitters, Welder helpers</td>
<td>100</td>
</tr>
<tr>
<td>Carbon Steel Welders</td>
<td>20</td>
</tr>
<tr>
<td>Alloy Welders</td>
<td>10</td>
</tr>
</tbody>
</table>
Other personnel categories will include management, engineering, supervision, technical personnel, quality control and inspection personnel and administrative support. These categories could represent an additional 10% in workers.

QPGGL aims at maximising the contracting of personnel from within the country to make every practical effort to provide preferential treatment (assessment, training, etc.) to using local craftsmen and labourers to supply the majority of the construction requirements for the Project. Some craftsmen that may be difficult to hire in the local area may be relocated to the site from other areas of Ghana, while some management, engineering, supervision and specialist personnel could be relocated from other parts of the world.

### 2.5.2 LNG Terminal Construction

#### 2.5.2.1 Construction and Support Vessels

The construction of the Project facilities would require the use of a variety of marine vessels, including:

- crane barges used during the fabrication of the offshore terminal and the lowering of some pipeline segments;
- a shallow water lay barge, secured to the bottom with temporary piles, used for the pipeline fabrication (e.g., welding and inspection);
- a dive support vessel, typically a spud barge, used for activities such as tie-ins, hydrotesting, and other dive-related functions;
- vessel support tugs used to spot the lay barge, other floating equipment, and to float pipeline segments into place;
- crew/supply boats used to shuttle personnel and supplies from the landside pier to the lay barge and dive support vessels; and
- pipe transport barges, shuttled by tugs, used to transport pipe segments from the pipe yard and the lay barge.

#### 2.5.2.2 Offshore Mooring Platform

The base case option for the offshore mooring configuration consists of a spread moored FSRU with import of LNG via ship to ship transfer, with conventional LNG carriers berthing against the FSRU. The offshore berthing platform would consist of tubular steel structures (jackets), pile structures, steel decks, and topside equipment.

A barge-mounted crane would be used to lift these structures from transport barges and then lower them into the water. Each structural jacket would be placed on mud mats on the seafloor.
prior to installation. A vibratory pile driver or diesel pile hammers would be used to drive the main piles through hollow jacket sleeves into the seafloor. The deck sections, module support frames, and module packages would be installed following the installation of the structural jackets and piles.

The topside equipment would be transported to the platform on prefabricated skid packages and a barge crane would be used to lift the equipment into place and secure them to the pier. All necessary connections would then be completed and the equipment would be tested.

QPGGL would pursue the use of prefabricated modular designs, made up of precast elements fabricated prior to delivery rather than on site. Use of precast elements would reduce the time and labour required on site, thereby reducing the potential safety and environmental impacts associated with working in a marine environment.

2.5.2.3 FSRU Fabrication and Installation

Golar LNG will provide an offshore FSRU, currently being constructed by Samsung Heavy Industries in South Korea, as well as technical, engineering, design and construction services. Details of the FSRU preliminary design and specifications are presented in Annexure A (Project design details and drawings).

LNG carriers and FSRUs normally do not have the capability to cool their cargo, but rely on efficient insulation (typically 30 –60 cm thick) to keep the LNG in a liquid state at a pressure very slightly above the ambient air pressure. The insulation may comprise bulk perlite material or rigid foam comprising polystyrene, polyurethane or phenolic resin. LNG carriers and FSRUs are adapted to use LNG vapours that boil off in the storage tanks as fuel gas.

As an FSRU, the vessel will be equipped with several 16-inch loading arms for the transfer of LNG from carriers and one 16-inch loading arm for vapour return to the LNG carriers. Water for the steam boiler and condensers will be extracted from the sea.

Once the FSRU mooring system and send-out pipeline are in place, deployment of the FSRU is a matter of bringing the FSRU from the shipyard to the intended installation site. Installation of the FSRU involves the hook-up to the pre-installed mooring lines and piles, tensioning of the lines, and the hook-up of the pre-installed risers to the turret. The PLEM serving as an anchor point for the pipeline must be pre-installed as well, using an offshore installation vessel.

2.5.3 Metering Facility

The Metering systems shall be designed to have a service life of at least 30 years. It is recognised that achieving this life will depend upon maintenance being carried out on the equipment at planned intervals. It is acceptable to replace consumables during planned maintenance interventions, such as worn parts, seals, gaskets and any components that cannot achieve the full service life. Details of the metering facility designs are presented in Annexure A (Project design details and drawings).

2.5.4 Pipeline and Associated Facilities

2.5.4.1 Applicable Codes and Standards

The primary design code shall be Ghanaian; where Ghanaian code is not available a relevant code from other codes and standards described below shall be used.

GS (Ghana Standards)
International Codes and Standards

Supplementary international codes and standards may be adopted for specific design areas. Codes and standards used for this project shall be the latest revisions including all addenda available at the time of purchase order placement.

- International Codes and Standards

- BS PD 8010-1 Code of practice for pipelines - Part 1: Steel pipelines on land,
- API ISO 3183 / API 5L Specification for Line Pipe,
- ASME B16.5 Pipe Flanges and Flange Fittings,
- API RP 2A WSD Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress Design,
- BS EN 1992-1-2 Eurocode 2: Design of concrete structures,
- IGEM/TD/1 Steel Pipelines and Associated Installations for High Pressure Gas Transmission.
- ASME/ANSI B 36.10 Welded and Seamless Wrought Steel Pipe.

2.5.4.2 Design Data

Pipeline design parameters for subsea spool, offshore pipeline and onshore pipelines are presented in Table 2-4.

Anti-Corrosion Coating

A suitable anti-corrosion coating should be used for subsea pipelines, spools and buried onshore pipelines. Piping or pipelines above ground (exposed) shall be required to be designed to withstand temperatures of up to 75°C, which is based on a black body temperature. These sections should be externally protected by an epoxy barrier paint system in accordance with ISO 12944-2 Category Im3 and qualified in accordance with ISO 20340.

Pipeline Trenching

The offshore pipelines will be laid on the seabed. Trenching/rock dumping/mechanical backfilling requirements will be determined in mechanical design.

The onshore pipeline shall be laid in trench with minimum 1.2 m top of pipe cover, except nearshore where the top of pipe cover shall be minimum 2 m. If trenching is not feasible, a suitable protection shall be provided either by rock dump or placing mattresses on the pipeline.

Mattress Protection/Concrete Weight Coating

If required, the pipeline/tie-in spool shall be mattressed for dropped object protection. Standard mattresses of 150mm, 300mm or 450mm thickness with a specific gravity between 2.4 and 3.6 shall be used. If required, concrete weight coating shall be based on a density of 2400 kg/m³.
<table>
<thead>
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<th>Property</th>
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<th>Subsea Spool</th>
<th>Offshore Pipeline</th>
<th>Pipeline to VRA and CENIT</th>
<th>Pipeline to KPONE</th>
<th>Pipeline to CEN POWER and ASOGLI</th>
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<th>Pipeline to ASOGLI</th>
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2.5.5  Proposed Landfall Construction & Pipe Installation Method

2.5.5.1  General

The following construction and pipeline installation options provide a basic typical installation methodology and should not be construed to limit installation to only these options.

The proposed method requires setting up an anchored winch some distance above HAT between the top of the landfall and the fishing harbour road. The pipe pull shall be from a shallow water pipelay barge (see Figure 2-24) through an already prepared trench protected with rock causeways.

Figure 2-21: Proposed Winch and Equipment laydown Location

2.5.5.2  Nearshore - Landfall – Onshore Site Preparation

Prior to any construction activity the site area will need to be cleared of all unwanted materials to provide safe access for construction equipment and personnel. It is envisaged that access ramps will have to be built from onshore down to the lower beach level. This can serve as entry and exit points for construction vehicles from the fishing harbour access road down to the site area. There is sufficient space above HAT to serve as equipment laydown area and temporary construction camp area.

2.5.5.3  Trenching and Trench Protection

A rock causeway 6 m wide (see Figure 2-22) shall be constructed either side of the proposed pipeline centre line from above HAT to -4m below Lowest Astronomical Tide (LAT) or marine dredging equipment access point. The sides of the causeways will be armoured with minimumD50 800mm stones (to be confirmed by installation contractor) to preserve the integrity of the causeways against waves and tidal action. The top of the causeway shall be prepared and graded to serve as access to the beach and nearshore zone.
The rock causeway shall also be built to a height greater than HAT to avoid flooding of the causeway running tracks.

Figure 2-22: Proposed Rock Causeway (seaward view)

A typical shallow water pipelay barge draft ranges from -3m to -5m water depth. Applying this to the offshore-nearshore-landfall profile requires that the rock causeway should run from HAT to approximately 900m offshore. Based on this length, it is envisaged that approximately 80,000 tonnes of rock is required to build both causeways. An alternative option is positioning the shallow water barge closer to shore by pre-dredging a channel through the sea bed as illustrated in Figure 2-23 below.

Figure 2-23: Proposed Dredging Works Profile

With the channel dredged as suggested above, the shallow water lay barge can achieve -4m water depth approximately 420m from shore. Consequently the rock causeways which were initially envisaged to run up to 900m offshore will now only be required up to 420m offshore. The resultant weight of rock required for the shorter causeway length will be approximately 44,000 tonnes. Other advantages to this option include:

- Using dredged material to build the causeways and
- A shorter lower risk shore pulls.
With the causeways in place, the trench in which the pipeline will be installed will be excavated using mechanical excavators working from the causeways (see Figure 2-22) or blasted with explosive chargers depending on the results of the geotechnical assessment.

To ensure the minimum protection cover requirement is met for the design life of the pipeline, the depth of burial at the landfall must account for potential erosion of soil cover, down cutting of the shore over the design life as well as protection against 3rd party damages. ISO 13623 does not specifically address the minimum required depth of trench or cover for the pipelines for a

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*Should results of the nearshore geotechnical assessment suggest that the area is made up of hard rock material thereby making typical dredging or trenching equipment inadequate for the planned works, the use of explosives may have to be considered. This may require sending divers down to drill holes in the sea bed to set up chargers. It is important that prior to any planned blasting activities a detailed methodology statement is pre-approved by Quantum. Blasting contractor will also have to demonstrate that blasting activities shall not have any detrimental effect on the environment and neither should it negatively impact on the structural integrity of the WAGP or any buried infrastructure within proximity of the Quantum Power proposed pipeline centreline.*
shore approach condition. It is therefore recommended that the pipeline minimum depth of cover between HAT and marine equipment access point is 2 m Top of pipe (T.O.P).

It is envisaged that the pipeline will be concrete coated to guard against buoyancy during the pipeline installation process. There is however significant risk to damaging the concrete coating on the pipe during pipe pull operations in excavated or blasted rocky areas. An even layer of bedding material (pea gravel) will be placed at the bottom of the trench; this bedding must be free of any object/material that could cause damage to the pipe coating and compromise the integrity of the pipeline.

2.5.5.4 Pipe-Pull

The proposed pipe-pull method is an onshore pull method which involves installation of a winch(s) pulling a pipe-string to the beach from a shallow water pipelay barge positioned as close as possible to the beach in order to minimise the length of a pipeline string to be pulled and to minimise the pull force required. Shallow water pipelay vessels generally require a minimum water depth of 3 to 5 metres\(^5\), which at the site will be in the order of 400 m to 500 m from HAT (post-dredging as illustrated in Figure 2-23).

This method of installation has been used successfully on many landfall projects with buoyancy sometimes added to a pipeline in order to ensure that there is sufficient reserve between the calculated pull-in force and the capacity of the pulling spread. All landfall preparations, including the setting-up of the winch(s) and pulling spread, are completed prior to the arrival on site of the pipelay vessel.

Once the lay vessel is in position offshore the pull-wires will be run from the lay vessel to the winch setup onshore. The vessel then commences a conventional pipelay installation with the winch(s) pulling the pipe off the vessel to a level above HAT as the welding of each pipe section is completed. Once the pull head is ashore, the shallow water barge will commence conventional pipelay operations laying away from the beach for the installation of the offshore portion of the pipeline.

The shallow water barge would lay the pipe to 20m to 25m water depth then laydown to be picked up by a deep water lay barge. In order to achieve the required pull force the onshore winch setup arrangement may consist of a single pull wire or multi-sheaved system. The winch(s) will be restrained by using buried sea-anchors onshore, rock anchors or a sheet piled anchor construction.

2.5.5.5 Landfall Reinstatement and Post-Construction

The construction area shall be reinstated and all excess spoil from trenching and causeway construction activities carted away and disposed of in an environmentally friendly manner. Excess spoil should also be re-used as trench backfill whenever possible. As a result of prevailing coastal erosion along the Ghanaian coast, it is recommended that the backfilled trench between HAT and -4m water depth be reinforced with rock armouring as part of reinstatement works.

It is also recommended that post installation monitoring surveys be carried out at the end of each rainy season to measure the effects of the elements on the pipeline cover.

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\(^5\) Vessel draft could be shallower than 3m depending of type of vessel and environmental conditions.
2.6 PROJECT PRE-COMMISSIONING PHASE

There are many different approaches, in terms of activities and sequences that may be adopted in testing and pre-commissioning the subsea, reception, distribution and delivery facilities. A practicable approach is outlined within this report, but it should be recognised that the EPC contractor may propose an alternative acceptable method of achieving the specified requirements.

2.6.1 Import Pipeline System Testing and Pre-commissioning

It is envisaged that the import and distribution sections of the pipeline system will each be tested separately. The import section will extend from the subsea PLEM/SSIV to a temporary test header at the onshore reception facilities. The distribution section will extend from the reception facilities to each user metering skid outlet ESDV.

The offshore section of pipeline will be pulled in from the pipelay vessel to the beach at the landfall and laid away to the FSRU location, terminating at the subsea end with a flange, which will be deployed to target box on the seabed. Where testing of the pipeline is to occur prior to tie-in to the PLEM/SSIV it is anticipated that the flange will be deployed with a PLR pre-installed.

The onshore section of the import pipeline will be installed from the beach up to the onshore reception facility area. Testing and pre-commissioning activities for the import pipeline system are described below:

Import Pipeline Cleaning, Gauging and Hydro-testing

Following installation, including any trenching and backfilling, the pipeline will be flooded from subsea to shore. Cleaning and gauging in accordance with ISO 13623 may follow, using pigs driven by the filtered and chemically treated testing medium from either the subsea or beach end to the PLR at the beach or SSIV/PLEM.

If a gauge plate cannot be used due to internal restrictions, an intelligent gauging tool such as a caliper pig will be used. Upon inspection and approval of the gauge plate the pipeline will be hydro-tested in accordance with ISO 13623 from either the offshore or onshore end.

Alternatively the complete import pipeline may be cleaned, gauged and hydrotested following installation of the PLEM/SSIV and tie-in spool.

PLEM/SSIV Structure

The SSIV structure will be pressure tested onshore as part of the Factory Acceptance Test (FAT). No post-installation strength tests are envisaged unless problems are subsequently encountered. The pig should be installed as far down the branch as possible to minimise the amount of water left in the piping, which may not be swept from the SSIV by the subsequent pigging operation.

Tie-in Spool

The spool to tie in the pipeline to the PLEM/SSIV structure will be fabricated onshore based on metrology carried out after installation of pipeline and PLEM/SSIV. The tie-in spool will be gauged and hydrotested at the onshore fabrication site as part of FAT. It will also be necessary to install a PLR at the PLEM/SSIV for subsequent operations.

Import Pipeline System Leak Testing
If the pipeline has been previously cleaned, gauged and hydrotested prior to installation of the tie-in spool, it will be necessary to perform a leak test on the spool connections.

**Import Pipeline Dewatering**

Following hydrotecting the pipeline may then be dewatered from the reception facilities to the SSIV/PLEM using dry air or nitrogen to run a pig train (see Figure 2-26). The inhibited water film left behind may be further swept by pigs driven by dry air or nitrogen. These pigs may form part of the dewatering pig train. Where further drying is not necessary and nitrogen is used, significant amounts will be required for dewatering.

The pipeline will be left filled with dry air or nitrogen slightly above the highest seabed ambient pressure. Alternatively the pipeline may be left full of water until after riser installation, when the riser and pipeline may be dewatered together. Where the pipeline is left full of air and is not to be further dried then it will be necessary to inject a slug of nitrogen at start-up to separate the air from the hydrocarbons.

![Figure 2-26: Dewatering Import Pipeline](image)

**Flexible Riser Leak Test and Dewatering**

The flexible export riser will be proof pressure tested prior to installation as part of its FAT test, and pressure/leak tested post installation. The riser will be installed flooded with test medium.

After a successful riser leak test the SSIV may be opened to drive the pre-installed pig(s) from the riser branch of the PLEM/SSIV to a temporary PLR installed at the top of the riser, using either the nitrogen/air in the import pipeline as a drive medium or by injecting nitrogen/air through the PLEM SSIV hot stab.

The pipeline system from the FSRU to the reception facilities is now nitrogen/air filled.

**Import Pipeline System Drying and Purging**

Should drying of the import pipeline be required, then dewatering may utilise air rather than nitrogen. Subsequent drying would then be accomplished either by vacuum or dry air, or both.

Following drying, the air will be purged from the import pipeline system using dry nitrogen. Alternatively the pipeline may be left air filled and a nitrogen buffer may be introduced to the pipeline at the FSRU during start-up to separate the air from produced hydrocarbons.

**2.6.2 Distribution Pipeline System Testing & Pre-commissioning**

The distribution pipeline system extends from the reception facilities to each end user metering skid. The system is comprised of two trunk lines with short branch lines to each end user. Each end of each trunk line and the end of each branch line will be provided with a flange to allow the connection of temporary PLRs for testing and commissioning purposes.

The onshore distribution pipeline system will be buried. It is envisaged that all branches will be installed and pre-commissioned along with the trunk lines, but that end users may come on-line at different times. The distribution pipeline system is shown in simplified form in Figure 2-27.
Cleaning and Gauging

The method selected to clean and gauge the branches may depend on their length, which will vary, depending on location. The method employed for the longest branch, which is expected to be circa 400 m long, may also be used for the shorter branches, although other acceptable methods may be considered to be more appropriate by the installer (see Figure 2-28).

Cleaning and gauging of trunk lines involves the installation of temporary PLRs at each end of each trunk line allowing a cleaning and gauging pig train to be run, probably using filtered and chemically treated seawater as a drive medium. Cleaning and gauging will most likely take place from the reception facilities. Any debris or gel plugs swept into the trunk line from the branches will be removed during this operation (refer to Figure 2-29).
Hydrotest and Dewatering

Upon inspection and approval of all gauge plates associated with a trunk line and its branches, the pipeline system will be hydrotested from the reception facilities. Following hydrotesting, the pipeline system may be dewatered. Unless the branch tees are equipped with a valve, bulk dewatering of the trunk lines will start prior to dewatering of the branches. A dewatering pig train will be driven through the trunk line by dry air. The train will probably be driven from the far end of the trunk line to the reception facilities, as disposal of the treated water may be easier at this location.

Following removal of the bulk of water from the trunk line by the initial pig train, gel pigs will be driven by dry air from the end of each branch line to sweep water into the trunk line. A second pig train will then be launched into the trunk line to sweep the water and gel pigs from the branch lines out of the trunk line. This process may need to be repeated several times until acceptably small volumes of water are removed from the trunk line with the final run.

The inhibited water film left behind may be swept by further pigs, which may form part of the dewatering pig train.

Drying

Should drying of the distribution pipeline be required, then this may be accomplished either by vacuum or dry air, or both. Vacuum drying can be a very slow process for long pipelines and therefore drying using dry air is probably the optimum method. Dry air may be introduced at either end of the trunk line and should initially be routed via the closest branch until the expelled air is dry to specification, at which time the air flow should be directed out of the next closest branch. In this manner a dry front will progress through the pipeline system until the entire distribution system is dry to specification.

Nitrogen Purging

Following drying and the hook-up and testing of the metering skids, the air will be purged from the distribution pipeline system using dry nitrogen. As for drying, purging should progress from branch to branch until the full system is nitrogen filled. Air/nitrogen may be expelled from the vent points at each metering skid and trunk line termination (see Figure 2-30).
2.6.3 SSIV Umbilical System Testing & Pre-commissioning

The SSIV umbilical system comprises a dynamic umbilical from the FSRU to the SSIV, plus the UTA and associated flying leads.

The umbilical will be fully tested by the manufacturer as part of FAT and umbilical EFAT, and hydraulic cores will be filled with the applicable hydraulic fluid at the manufacturer's facility.

Offshore tests will be in accordance with ISO 13628-5. During installation, the cores will be continuously or periodically monitored to confirm that all hydraulic cores and electrical cables are behaving as expected, and to give an early indication that damage has not occurred. Immediately following successful installation and connection to the TUTU at the FSRU the umbilical will be tested to confirm that no damage has occurred during installation and the TUTU connections are sound. The umbilical will then be tied in to the SSIV/PLEM and tested as described below. Tests will be carried out immediately after tie-in to confirm that no damage has occurred.

Testing of Hydraulic Cores

Once tied in, all connections will be leak tested by pressurizing each umbilical core in turn. A dedicated pump at the FSRU TUTU is usually used for this but it is sometimes more practical to use the HPU for this test.

Testing of Umbilical Cables

The subsea umbilical termination (UTA) will be provided with shorting caps on all electric lines to facilitate electrical continuity and IR testing in accordance with ISO 13628-5 from the FSRU. Additionally TDR testing may be performed to confirm integrity.

Testing of Flying Leads

All flying leads will be subject to FAT prior to shipping offshore and will be filled with the applicable hydraulic fluid.

Hydraulic flying leads will be tested after installation by pressurizing the umbilical cores and checking for pressure drop or visible leakage. These tests are normally conducted at working pressure using the HPU.

Figure 2-30: Nitrogen Purging
Electrical flying leads are generally tested during pre-commissioning of the SSIV. Successful powering of, and correct read-back from, the SSIV sensors is taken to indicate successful installation of the flying leads.

**Displacement of Umbilical Cores**

Hydraulic cores will be installed filled with hydraulic fluid and will not therefore require displacement. During pre-commissioning SSIV valve operations will be used to flush out the limited quantity of seawater that may be ingested during deployment of the controls equipment.

### 2.6.4 SSIV/PLEM Testing & Pre-commissioning

The SSIV will have been through FAT (including hydro-testing) and EFAT at the supplier’s facility.

Pre-commissioning of the SSIV will be controlled and monitored via a direct control system. Subsea sensors and solenoid valves within the HPU will be connected directly to the FSRU PAS/ESD system. Pre-Commissioning will be carried out from the FSRU with a vessel and/or ROV on station to observe at the SSIV. Testing and pre-commissioning will include:

- Valve operation tests including timing and foot-printing
- Subsea sensor tests
- Shutdown tests including ESD functions.
- Performance testing
- Partial closure tests
- De-isolation of SSIV

Many of these tests will be conducted in concert with the SSIV control system and PAS/ESD system pre-commissioning.

### 2.6.5 FSRU Testing & Pre-commissioning

Qualification requirements for platform equipment will be as for subsea equipment. However, because conditions on the FSRU are not extreme, it is likely that pre-qualified components will be available.

The main areas of work on the FSRU that are related to the import pipeline system are:-

**Installation and tie-in of riser(s)**

The riser will be tied in to the FSRU pipe work as part of the installation process. A leak test of the FSRU interface will be carried out as part of the riser leak tests

**Installation and tie-in of SSIV control system components**

All SSIV Control System (SCS) components will have completed the testing programme (FAT & EFAT) before being installed on the FSRU in the shipyard. After installation and tie-in, testing and pre-commissioning will consist of leak testing tubing, filling reservoirs, and power-up tests to confirm full functionality of monitoring, operating and shutdown functions of the SCS. Final interface testing will be performed on the HPU to ensure that it is fully integrated and working with the ICSS systems (PAS and ESD) prior to sail-away of the vessel.

**Installation and tie-in of the SSIV umbilical**

The SSIV umbilical will be pulled in to the FSRU, hung off and connected to the Topside Umbilical Termination Unit (TUTU). Leak testing and electrical testing of this interface will occur as part of the umbilical tests.
Instruments and ESD Interfaces

All instrumentation tied back to the ICSS, primarily instrumentation associated with the SSIV, will be tested and commissioned from the Control/Equipment Room. Tests would include functionality, alarms, trips, etc. All interfaces to the ESD system will be tested as part of package pre-commissioning.

2.6.6 Onshore Facilities Testing & Pre-commissioning

Qualification requirements for onshore equipment will be as for subsea equipment but as there are no novel features it is anticipated that pre-qualified components will be available. The main areas of work at the onshore facilities are:

Installation and tie-in of reception facility / end user metering skid

The metering skids at the Reception Facility and end user delivery points will have undergone FAT (including hydro-testing and functional tests) and EFAT at the supplier's facility.

Each metering skid will be controlled and monitored via the reception facility ICSS. The end user metering skids will be connected to the ICSS via the RTU and telemetry system. Pre-commissioning will include leak tests to verify the interfaces with the facility piping and confirmation that each metering skid is functioning and that data is transmitted correctly to the ICSS.

Installation of the reception facility / end user piping and valving

In addition to the metering skids, the reception and end user delivery facilities will be include further process piping components including pipe spools, isolation valves, pressure control valves, filters, ESDVs etc.

All items will have undergone hydrotesting and, where applicable, functional tests during FAT at the suppliers facility. Pre-commissioning will include leak tests to verify the integrity of connections and shut-offs and functional tests to confirm that the equipment operates correctly.

Installation of the reception facility ICSS

The ICSS will have undergone extensive FAT and EFATs at the suppliers' works to prove the functionality of the hardware and software, and the operability of interfacing equipment, either real or simulated.

Pre-commissioning will verify all interfaces and functionality, including read-back of all data points and operation of all control functions. This will include control and monitoring of the end user metering facilities via the telemetry links.

The ESD system(s) will undergo full end-to-end tests to verify functionality and the correct implementation of the relevant cause and effects. Similarly the fire and gas system will be fully tested.

Installation of the reception facility / end user control equipment

Controls equipment such as process transmitters and hydraulic power packs will have been subject to FAT at the suppliers' works. For relatively complex equipment such as HPU's this will also have included interface testing (i.e. EFAT) with the ICSS.

Individual pieces of equipment such as process pressure and temperature transmitters will be tested individually following installation and further tested along with the HPUs as part of ICSS pre-commissioning.
Installation of the reception facility power and utility systems

The power and utility systems, which may include generators, switchboards, compressors, HVAC, lighting, UPS etc. will be fully tested as part of pre-commissioning. For significant items, such as generators, this will follow FAT at the suppliers.

Installation of the telecoms system

The telecoms system will be fully tested during FAT and EFAT with the ICSS. Pre-commissioning will verify that the equipment operates correctly in isolation and in concert with the ICSS as part of ICSS pre-commissioning.

2.7 PROJECT OPERATION PHASE

The Tema LNG Import Terminal enables natural gas from a Floating Storage and Regasification Unit (FSRU) to be transported to shore, fiscally metered, distributed to various users, and controlled to maintain the required delivery pressure.

Operation of the proposed Project would involve importation and transfer of LNG to the FSRU from LNG carriers, regasification of LNG on the FSRU, and transfer of regasified LNG (natural gas) into the 24" subsea pipeline and ultimately into the onshore distribution pipeline network. Figure 2-31 presents a schematic diagram of the overall process. The key components of operation for each of these activities are described in the following sections.

2.7.1 Conditioning of Pipeline System for Start-Up

Pre-Commissioning of the FSRU, riser, PLEM/SSIV, umbilical, pipelines and onshore facilities will leave the import pipeline filled with nitrogen or air and the distribution pipeline systems filled with nitrogen. The ROV operated PLEM/SSIV isolation valves will have been opened in preparation for the start-up sequence as part of pre-commissioning.

Further de-isolations, which will be exercised from the FSRU control room as part of the start-up, would include opening the riser ESD valve and the ESD valves at the metering stations.

2.7.2 Initial Start-Up

After pre-commissioning and conditioning is complete, the pipeline system may be started up. The base case is that at the end of the pre-commissioning phase the import pipeline will be left packed with dry nitrogen at a pressure just above maximum ambient seabed pressure. The distribution pipe work system may be nitrogen packed at a lower pressure. Prior to, or during, start-up it will therefore be necessary to equalise the pressure in the two sections of pipeline. This may be achieved using the pressure control valve at the reception facility.

At start-up the nitrogen in the pipeline will be displaced by produced gas. The branched nature of the distribution pipeline means that it will be necessary to purge nitrogen from all branches, even though all end users may not be prepared for start-up at the same time. Consequently it is assumed that a temporary vent/flare stack(s) will be sited at the end of each distribution branch and that the pipeline contents will be diverted to the stack until gas is received which meets the required specification for the power station. Branches may then remain gas filled until the power station is ready to accept gas.

As for purging, nitrogen venting should progress from branch to branch, starting with the branch closest to the reception facility, until the full system is gas filled. Once the pipeline has reached operating pressure and any necessary shut-down verification tests have been completed, the
power stations may come on-line. Should the branches be provided with an isolation valve at the tee, then each branch may be commissioned separately as required.
Figure 2-31: Schematic diagram of the overall process
2.7.3 LNG Terminal Operation

The FSRU is to be capable of accepting LNG from LNG carriers (LNGC). The FSRU storage capacity is projected at 170,000m$^3$ of LNG equivalent to 100 million cubic meters of natural gas. The LNG will be delivered into the FSRU from a delivery carrier approximately every two weeks and steadily re-gasified. The terminal will have a re-gasification system to "vaporise" the LNG and send it as natural gas to the coast. The LNG re-gasification will be carried out in heat exchangers mounted on the terminal, which will use seawater.

The arrival and berthing of tankers with LNG cargo will be performed against the wind and preferably in daylight. During the manoeuvres, tugboats will be required and connected to the tanker when at its final docking position. Once the tanker is anchored, it should be noted that all tanker lines and connections allow for rapid release, and emergency tow lines should also be available to accommodate possible contingencies.

The LNG transfer from the tanker to the FSRU will be conducted using articulated arms as shown in Figure 2-32. When filling the FSRU tanks, BOG (boil off gas) will be generated; these gases will be returned to the tanker through a system of articulated arms.

Vapour return to the LNGC cannot be guaranteed and hence the FSRU boil-off gas compression system needs to accommodate the total vapour displacement capacity. However, consideration needs to be given to the re-vaporisation capacity of the LNGC which may dictate a longer load-out under these conditions. Hence, the use of the FSRU duty and stand-by compressor operating simultaneously under these conditions may be deemed acceptable.

![Figure 2-32: LNG Transfer Operations](image)

The loading arm and cryogenic hose system shall be integrated into the manifold system, to allow for loading of all cargo tanks individually but also simultaneously from any LNG loading arm. This shall be facilitated by valves and should not require removing of spool pieces. Each loading arm shall be able to be disconnected individually without compromising the ability to load LNG.

The manifold system shall be configured to allow all vessel operations to take place if one tank is taken out of service, and or one tank is in the process of being warmed-up or cooled down. The manifold shall allow for a recirculation of LNG and NG to maintain individual systems at cryogenic temperatures at all times.
During operation, the water line would remain at about the same level on the FSRU as a result of ballasting operations during unloading of both the LNG carriers and the storage tanks on the FSRU.

2.7.3.1 LNG Regasification Process

LNG supplied to the FSRU will be stored in LNG tanks at approximately -161°. Cryogenic pumps will supply LNG to Hamworthy ‘cascade-type’ regasification equipment under pressure. The cascade regasification system will use heat from sea water to raise the temperature of the LNG to convert it to gas in a three-stage process. Figure 2-33 illustrates a typical Hamworthy regasification system.

LNG will be regasified using the Open Loop Regasification Process as discussed below. For the re-gasification process, sea water will be extracted at up to 9,000 m³ per hour from an intake point of 1.5 m diameter, from the stern of the FSRU. It will be screened, treated with sodium hypochlorite and pumped through welded plate type heat exchangers. This heat exchanger will transfer heat from the seawater to a propane intermediate medium. The propane will vaporize in the heat exchanger and will leave the heat exchanger at 6°C and 5.7 barg.

The propane vapour will be circulated to Printed Circuit Heat Exchangers (PCHE) where the primary heating and regasification of the LNG takes place. The PCHE heat exchangers will transfer heat from the propane to the LNG that will be supplied from storage at -161°C. Heat loss will condense the propane in the PCHE and it will be pumped back to the welded plate heat exchanger as a liquid. Heat transfer to the LNG will raise the LNG temperature and vaporise the LNG, converting it to gas.

A final stage non-contact heat exchanger can be used to transfer heat from seawater to the LNG/gas stream exiting the PCHE heat exchanger without an intermediary fluid. The sea water will leave the regasification unit, 9°C colder than the ambient water temperature, and will be discharged to the sea. Figure 2-34 illustrates the regasification process and main emissions.

The pressure of the gas stream from the vaporisers will be regulated to a send-out pressure that will never exceed the pressure specification of the existing onshore pipeline.

Figure 2-33: Regasification Equipment
2.7.3.2 FSRU Water Discharge Characteristics

As part of the FSRU operation scheme, two seawater Intake-Outfall systems are included:

- One for the vaporiser unit, and
- One for the condenser unit

The vaporiser unit uses seawater at a rate of 9,000 cubic meters per hour (2.5 m³/s). This water will be treated and pumped through welded plate type heat exchangers. The heat exchanger will transfer heat from seawater to a propane intermediate medium. The vaporizer outfall will discharge cooled seawater from the heat exchangers in the regasification process with a temperature that has been lowered by 9 °C from ambient.

The condenser outfall will discharge cooled water with a temperature that has been increased by about 4 °C. This water will be warmer and less dense than the ambient seawater and will tend to rise to the surface.

Table 2-5 shows the main characteristics of the seawater Intake-Outfall systems.

Table 2-5: Main Characteristics of Water Discharge Sources

<table>
<thead>
<tr>
<th>Installation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Condenser Outlet</strong></td>
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<tr>
<td>Discharge Port Diameter</td>
<td>1.5 meters</td>
</tr>
<tr>
<td>Maximum Hourly Rate</td>
<td>10,000 m³</td>
</tr>
<tr>
<td>Flow (in m³/s)</td>
<td>2.77 m³/s</td>
</tr>
<tr>
<td>Thermal Change</td>
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</tr>
<tr>
<td>Position in Reference to MSL</td>
<td>-3 m</td>
</tr>
<tr>
<td><strong>Vaporiser Outlet</strong></td>
<td></td>
</tr>
<tr>
<td>Discharge Port Diameter</td>
<td>1.5 meters</td>
</tr>
<tr>
<td>Maximum Hourly Rate</td>
<td>9,000 m³</td>
</tr>
<tr>
<td>Flow (in m³/s)</td>
<td>2.50 m³/s</td>
</tr>
</tbody>
</table>
2.7.4 Subsea Pipeline

The subsea pipeline will not have any instrumented control devices which operate under normal operating conditions; however it will be fitted with a Subsea Isolation Valve (SSIV) located within the PLEM structure. The purpose of the SSIV is to provide a reliable means of remotely isolating the inventory within the gas export pipeline in the event of a leak from the subsea pipeline or riser. The SSIV will provide the following benefits:

- Limit the duration of a gas release and hence the size of any fully developed flammable volume which may result.
- The duration of a fire (should the gas release be ignited) and hence the potential that the fire might escalate, is reduced.

2.7.5 Import Terminal / Individual Gas User Metering (Functional Description)

The primary function of the Import Terminal Metering System is to meter gas arriving at the terminal and being exported from the terminal to the gas users.

The primary function of the Individual User Metering Stations is to fiscally meter gas supplied to the gas users. The metering design flow rate will be different for each user, as shown in Table 2-6 below:

<table>
<thead>
<tr>
<th>IPPs</th>
<th>Required Gas Flow rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>CENIT Energy Ltd</td>
<td>30 MMscfd</td>
</tr>
<tr>
<td>Sunon Asogli</td>
<td>36 MMscfd</td>
</tr>
<tr>
<td>VRA Tema Thermal 1 (TT 1)</td>
<td>30 MMscfd</td>
</tr>
<tr>
<td>VRA Tema Thermal 2 (TT 2)</td>
<td>15 MMscfd</td>
</tr>
<tr>
<td>VRA Mine Reserve Plant (MRP)</td>
<td>24 MMscfd</td>
</tr>
<tr>
<td>VRA Kpone Thermal</td>
<td>60 MMscfd</td>
</tr>
<tr>
<td>Cen Power Generation Co.</td>
<td>60 MMscfd</td>
</tr>
<tr>
<td>Sunon Asogli (Phase 2)</td>
<td>60 MMscfd</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>315 MMscfd</strong></td>
</tr>
</tbody>
</table>

2.7.6 Onshore Distribution Network

The onshore gas distribution network initially consists of a pipeline with tie-in connections for the four gas users:

- CENIT Energy Ltd
- Sunon Asogli
- Cen Power Generation Co.
- Volta River Authority (VRA)

An additional tie-in connection will be provided for supply of gas to ‘future users’.

At each end user, a gas user metering facility will be provided. This will comprise:
- Inlet and outlet ESDVs
- A PCV which will ensure a constant supply pressure eliminating fluctuations in the distribution network operating conditions.
- A metering skid, consisting of 2 x 100% ultrasonic flow meters.

These gas end user metering skids are located adjacent to the end users facility and will be fenced off with controlled access.

2.7.7 Utilities

2.7.7.1 Pipeline Leak Detection

A leak performance study that considers risk assessment shall be conducted that determines the impact of the pipeline leak or rupture on the neighbouring community, highway traffic, and environment. The study shall consider minimum response time and the amount of product expected to be released until total isolation is achieved. The study shall determine required leak detection system performance criteria and performance considerations for the pipeline or pipeline network under consideration.

The gas is metered before it leaves the FSRU and as it arrives at the Import Terminal. The difference between the gas mass flow at the FSRU and the Import Terminal could be used to indicate a leak. The position of the leak could then be determined using a pig with acoustic equipment onboard.

Detecting leaks in the onshore pipelines is more problematic as there is a common metering system (Import Terminal) measuring the supply of gas to the two onshore pipelines, which have several branches off each pipeline. The gas is metered at each the end of each branch and therefore by summating the flow from each branch metering system and comparing with the metered flow into the pipelines a leak could be detected. The problem arises in trying to locate the leak using a pig, as both pipelines could require pigging depending upon which pipeline is leaking and which pipeline was pigged first, also the branches to the end users have no connections/facilities to allow them to be pigged, therefore, during detail design, a review, of the commercially available leak detection systems shall be carried out to determine the most suitable system for detecting leaks in the sub-sea and onshore pipelines.

2.7.7.2 Power Supplies

Power to the Import terminal shall be supplied from the National grid with a back-up diesel generator. Power to the individual metering stations shall be supplied from the National grid.

Measurement and control systems are normally considered critical for the safe operation of the plant and therefore secure uninterrupted power supplies shall be provided at the Import terminal and at each individual metering station.

Instrumentation including analogue systems, alarms and shutdown systems etc. shall generally operate on 24 VDC. The 24 VDC shall be derived from the main AC power supply via rectifiers. Batteries & battery chargers will provide a secure supply. The battery system capacity shall ensure normal operation of the 24 VDC system for 12 hours.

Instrumentation requiring a secure 230 V 50Hz supply, such as analysers etc., shall be supplied with a back-up system consisting of static inverters powered from a secure DC system.
2.7.7.3 Flare System

A portable flare system will be brought in to the Import Terminal to allow for manual depressurising of the subsea pipeline, the Import Terminal and the onshore pipelines to the power stations.

Each individual metering station shall have connections for manual depressurising to a portable temporary flare stack.

2.7.7.4 Pipeline Pigging

The sub-sea pipeline shall be designed for infrequent intelligent pigging, space and connections shall be reserved, at the Import Terminal, for installation of a temporary demountable pig receiver.

The onshore pipelines shall be designed for infrequent intelligent pigging, space and connections shall be reserved, at the Import Terminal, for installation of two temporary demountable pig launchers (i.e. one for the Gas Pipeline East and the other for the Gas Pipeline West). Space shall be reserved at the end of the East and West gas pipelines for installation of temporary demountable pig receivers.

The pig receiver/launchers shall be self-contained including all interlocks for safe operation during pigging of the pipeline.

2.7.7.5 Telecommunications

Import Terminal and Quantum Offices

The main communication infrastructure between the Import Terminal facilities and the Quantum accounting and allocation systems office shall be via a secure broadband connection, using a suitable encryption standard.

Telecommunications equipment is to be installed for both voice and data communications between the Metering Terminal and the Quantum accounting and allocation systems office.

Individual Metering Stations and the Import Terminal

Data from each individual gas user metering system will be transmitted back to the Import Terminal via an Inmarsat satellites and terminals. The data will be fed to the Supervisory/Database computer before being transferred onto the Quantum accounting and allocation systems office via a secure broadband connection, using a suitable encryption standard.

Import Terminal and FSRU

Communication between the FSRU and the Import Terminal will be achieved via an Inmarsat satellite system or a LOS microwave communications system.

Information to/from 3rd Parties

The end users require the data from the dedicated fiscal metering system and gas composition from the analysers to be made available for daily nomination purposes. The end user will also require status indication of the FSRU, Import Terminal and end user metering station to give a warning of shutdown status and interruption of gas supply.

The end user shall be required to provide real time data to Quantum relating to either a cut-back in demand or no demand for gas.

Public Address System
The Import Terminal is considered to be sufficiently small enough that a public address system is not necessary, particularly as the terminal is normally unmanned. Personnel will be issued with intrinsically safe UHF hand-held radios when visiting the Terminal for inter-personnel communication. Terminal emergency alarms will be announced audibly over sounders providing specific tones, with flashing lamps.

**Close Circuit Television (CCTV)**

The Import Terminal and each individual secure metering compound will be provided with video surveillance cameras.

### 2.8 PROJECT CLOSURE AND DECOMMISSIONING PHASE

#### 2.8.1 Introduction

The LNG facility has a nominal project life of 10 years but may continue operations for a longer period. Nevertheless, planning is required for its eventual closure. This section outlines the closure and decommissioning stages which will be required for the Tema LNG facility.

Prior to site closure and the removal of any buildings or other infrastructure from the site, a series of stakeholder discussions will be held to determine the agreed end land use and fate of the LNG facility site and associated infrastructure. This will guide decisions about whether equipment or facility should remain on-site for future use, or if they should be decommissioned and removed. Once it has been determined which components of the facility will be decommissioned, a site decommissioning and closure plan will be developed in conjunction with the regulatory authorities at least five years prior to closure. At that time there will be a greater understanding of the relevant decommissioning standards and alternative land uses available for the site. All decommissioning works will be conducted in accordance with standard practices applicable at the time including requirements of the International Maritime Organisation (IMO)\(^6\).

It is likely that the LNG facility and its associated infrastructure will be valuable either as a package or as individual elements to other industrial or commercial users. Proximity to an industrial harbour in an area with developed physical infrastructure and considerable energy and raw material resources suggests that the most probable decommissioning activity will be preparation of the site for alternative industrial uses.

The closure and decommissioning plan has its focus on protecting public health and safety, improving or eliminating environmental damage and liabilities, and ensuring that post-project land use is similar to pre-project use or an acceptable alternative.

The following will occur prior to decommissioning of the site:

- Any new onshore and marine facilities will be designed to mitigate environmental impacts;
- The LNG facilities will be operated to mitigate environmental impacts;
- A preliminary site contamination/facility inventory will be developed;
- Site inspections and hazard characterization will take place and concerns will be identified;
- Communication with nearby communities to obtain relevant community input to the final decommissioning plan; and

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2.8.2 Decommissioning Activities

Detailed plans for facility closure, decommissioning and facility/ROW reinstatement will be developed towards the end of the project lifetime. It will prescribe performance criteria and a warranty period that will include inspection and monitoring to ensure the desired outcome (i.e. a stable self-sustaining landform) is achieved.

The decommissioning plan shall also take into account environmental rehabilitation. Environmental rehabilitation will include the removal of all surface facilities and excess hydrocarbon waste, as well as re-vegetation of localized natural flora.

Associated decommissioning activities in accordance with environmental measures and standards of good practice are listed below:

- removal of site infrastructure and waste:
  - all civil structures and associated infrastructure will be removed;
  - all remaining materials and hydrocarbons and hazardous waste will be removed;
  - all pilings and trestles will be removed;
  - all waste will be disposed of in an appropriate manner; and
  - reusable materials will be resold or recycled.

Hazardous Waste Clean Up and Transport:

- when decommissioned, all products within piping and storage infrastructure shall be removed from said system along with all associated infrastructure and possible contaminated soils; and
- all hazardous wastes shall be transported to approved hazardous waste storage facilities or disposal sites.

Site Rehabilitation:

- all disturbed areas due to ROWs, transmission lines, etc. shall be rehabilitated and revegetated;
- native flora shall be used to re-vegetate the rehabilitated sites;
- Roadways will be scarified; and
- Natural drainage patterns will be reinstated where practical.

Employment and Business Opportunities:

- trained personnel from facility operations will be used where possible; and
- additional rehabilitation crews shall be hired to assist with decommissioning.

2.8.3 Site Rehabilitation

Progressive rehabilitation (where practicable) of the LNG facility and associated infrastructure will occur for areas that have been disturbed.

The specific goals for rehabilitating the LNG facility site are as follows;

- **Achievement of acceptable land use suitability** – Rehabilitation will aim to create a stable landform with a post-project land use capability and/or suitability similar to that prior to disturbance, unless other beneficial land uses are pre-determined and agreed;
• **Creation of stable landform** – The site will be rehabilitated to a safe condition that is self-sustaining or to a safe condition where maintenance requirements are consistent with an agreed post-project land use; and
• **Preservation of downstream water quality** – Surface and ground waters that leave the site will meet accepted closure criteria. Current and future water quality will be maintained at levels that are acceptable for users downstream of the site.

Indicators and closure criteria will be developed for each of these goals in a closure plan that will be prepared in consultation with the appropriate stakeholders prior to site closure.

2.8.3.1 **Land Suitability**

Prior to the establishment of the LNG facility, land use was predominantly industrial activities with subsistence farm land and disturbed areas of native habitat.

Although detailed closure options are not currently available, should no future land uses be determined prior to closure, it is assumed that the site would be returned to an industrial use with minor areas of native habitat.

2.8.3.2 **Rehabilitation Strategy**

The rehabilitation strategy will be flexible and will be amended as new rehabilitation techniques are developed. Where possible, progressive or temporary rehabilitation of site areas will be undertaken. It is however expected that the majority of the site rehabilitation will be undertaken at site closure.

To achieve the rehabilitation objectives, rehabilitation of the site will be conducted so that;

- Suitable species of vegetation are planted and established to achieve the nominated post-facility land uses;
- The potential for water and wind induced erosion is minimised, including likelihood of environmental impacts being caused by the release of dust;
- The quality of surface water released from the site is such that releases are not likely to cause environmental harm;
- The water quality of any residual water bodies meets criteria for subsequent uses and does not have the potential to cause environmental harm; and
- The final landform is stable and not subject to slumping or erosion that would result in the agreed post-facility landform not being achieved.

2.8.3.3 **Success Criteria**

During the development of the decommissioning plan, preliminary success criteria (or closure criteria) for the rehabilitation areas will be developed. The success criteria are performance objectives or standards against which rehabilitation success in achieving a sustainable system for the proposed land use is demonstrated. Satisfaction and maintenance of the success criteria will demonstrate that the rehabilitated landscape is ready to be relinquished and handed back to stakeholders in a productive and sustainable condition.

The success criteria are likely to include indicators for vegetation, fauna, soil, stability, land use and safety on a domain basis that reflects the nominated post-facility land use.

2.8.3.4 **Monitoring**

Monitoring of the rehabilitated areas will be undertaken during the initial vegetation establishment period and beyond to determine whether the objectives of the rehabilitation
strategy are being achieved and whether a sustainable, stable landform condition has been attained. Monitoring will include inspections for the following key aspects:

- Soil erosion
- Revegetation success;
- Weed infestation; and
- Integrity of water diversion drains, waterways and sediment control structures.

Monitoring will be conducted by suitably skilled and qualified persons at locations which will be representative of the range of conditions on the rehabilitating areas. Annual reviews will be conducted on monitoring data to assess trends and monitoring program effectiveness. The outcome of these reviews will be included in reports to the relevant government authorities.

Maintenance works will be undertaken to address any deficiencies or areas of concern identified from the monitoring. This may include the re-application of topsoil, re-seeding, re-planting, weed control, additional fertilizer applications, de-silting or repair of drainage works and infill and re-grading of eroded areas.

2.8.4 LNG Terminal/Facility Decommissioning

It is expected that individual items or equipment and the LNG facility as a whole will be decommissioned when its operation is no longer economically viable. The overall aim of the decommissioning plan will be to ensure that the site does not pose an on-going risk to public safety or the quality of the environment and fulfils community expectations. The decommissioning plan will be prepared for the facility before decommissioning work starts, in consultation with regulatory authorities and relevant stakeholders.

Prior to removal, equipment will be depressurized, purged and flashed of hydrocarbons and other products to prevent uncontrolled release of hazardous materials, potentially leading to an explosion or contamination. Current expectations are that equipment that can be salvaged will be reused or resold. Where feasible, materials that cannot serve their original purpose will be recycled or scrapped. The aim will be to minimise the amount of waste requiring disposal.

Should project-related infrastructure require decommissioning, negotiations will be conducted with relevant stakeholders as to the benefits of retaining some of the infrastructure for future use (e.g. roads, pipelines, etc.). Infrastructure will only be left after decommissioning where formal written agreements have been obtained from the relevant stakeholders for its use and maintenance/management.

The management strategy for decommissioning activities is outlined in the following sections.

2.8.4.1 LNG Storage Tank Decommissioning

Removing Liquid from the LNG Storage Tank

LNG pumps will be used to pump as much LNG out of the storage tanks as possible. The net positive suction head required (NPSHR) for the LNG pumps will determine the lowest level the tanks can be pumped down to.

It is estimated that this level would be about 1 m of liquid level left remaining in the tank. During this process, the pumps would be carefully monitored for cavitation. Once the LNG can no longer be pumped out, the remaining LNG must be vaporized by adding heat into the tank. This is usually done by heated fuel gas or nitrogen.

Isolating the LNG Storage Tank
The objective of isolating a storage tank is the prevention of any re-entry of LNG or hydrocarbons. This is usually accomplished by providing a physical gap (air gap) between the tank and any piping containing hazardous fluid or gas. If the purpose of isolating the LNG tank is for personnel inspection, maintenance, or entry, the storage tank isolation shall comply with all applicable facility and regulatory safety procedures.

**Sampling**

Before purging begins, the initial tank pressure and temperature will be recorded. After the purging has begun, the following data will be collected:

- storage tank pressure;
- purge gas flow rate;
- percentage of combustible gases in the vent gas; and
- quantity of purge gas used.

**Purging of Tanks**

After the LNG has been removed, the tank warm-up and inert gas purge is initiated. The tanks will then be heated to temperatures above that of the atmospheric dew point. Raising the storage tank temperature above this level prevents moisture in the air from forming condensation in the insulation and on the tank surfaces.

During the inert gas purge, additional heat may be required to reach the desired warm-up in a reasonable time. The vent gas will be monitored during the purge for combustible gases. The end-point for the inert gas purge will be when the combustible gas readings on the gases venting is below the combustible threshold.

Vapor from the LNG storage tank will be vented to the atmosphere. The inner tank, dome and annular space between the inner and outer tanks will be purged of combustible gases with an inert gas. If personnel entry is required, after the combustible gases are purged out of the tank, a purge process will begin to purge the inert gases out using air.

**2.8.4.2 System Decommissioning**

The decommissioning of facility systems is necessary whenever inspection, maintenance, or dismantling is to occur. System decommissioning procedures will be written specifically for each system and equipment. Each procedure will address necessary safety and environmental activities, such as, purging (similar to tanks), electrical isolation (lock out/tag out), air gap isolation, piping valves to be locked and tagged out, safety and environmental monitoring, among others.

**2.8.4.3 Facility Abandonment**

Prior to abandonment, a review of the site infrastructure will be carried out to address items to be decommissioned and abandoned and items to remain for use by the community. The following items will be addressed during abandonment process:

- Hazardous chemicals, reagents and materials will be removed for re-sale or proper disposal.
- Equipment will be disconnected, drained and cleaned, disassembled and sold for reuse or to a licensed scrap dealer. This includes tanks, mechanical equipment, electrical switchgear, pipes, pumps, vehicles, laboratory equipment and office furniture.
- Any equipment deemed potentially hazardous will be removed from the site and disposed of in accordance with specific environmental regulations.
• Buildings, surface structures, and other infrastructure, which will no longer be required by the authorities or the community will be properly dismantled, demolished and removed.
• Concrete foundations will be demolished to or near surface grade and the concrete debris disposed of in an appropriate landfill. Buildings or foundations to be retained will be examined and passed as fit for occupation, failing which they shall be dismantled and removed as described above.
• An assessment of soil contamination in the location or vicinity of the buildings and other facilities will be completed and appropriate remediation measures will be implemented to treat or excavate and remove contaminated soil as required.
• Where possible, any sheer slopes or sharp elevation changes will be graded or fenced in consultation with the authorities and the local community. Fencing will remain in place to protect the public where sheer slopes exist or there are sharp elevation changes, if not the fences will be removed and the posts excavated.
• Access and site roads deemed no longer required will be reclaimed by removing the wear or asphalt surface and scarifying the surface. Where erosion and sedimentation is a potential concern, suitable plant species will be established along the prepared roadway surface. For areas where erosion and sedimentation are not a concern the scarified surface will be left to re-vegetate naturally. Culverts will be removed and natural drainage patterns will be restored wherever practical.
• Re-vegetation will be systematically assessed and implemented where practical, including seeding and reforestation through the introduction of indigenous vegetation and organic material.
• Power to the site will be terminated and the service disconnected at the source. The electrical lines along with the poles will be removed.
• The equipment associated with the water supply will be removed and any drilled well holes will be plugged with concrete. The underground water line will also be removed and the area graded.
• Site lighting will be removed along with all lighting hardware and poles. Underground pipes, conduits and cables will be terminated a minimum depth below the surface grade and allowed to remain unless there is a regulatory stipulation to remove them, in which case they will be removed and the areas graded and rehabilitated.
• The LNG loading facilities will be dismantled and the piles cut off at the seafloor should a future use for these facilities not be identified. The risers and the mooring chains will be disconnected, and the unit can be taken to a scrap yard. The tanks may be re-used, as they have a very long design life. Also the PLEM can be removed by cutting it loose from its anchor piles.

The removal of these facilities is a major undertaking and could result in a greater environmental disturbance than leaving them in place.

2.8.4.4 Onshore and Offshore Pipelines

The distribution onshore pipeline laterals will be cut at their respective beaches, flushed, capped, and abandoned in place. If required by the regulations in force at the end of the project lifetime or by the local communities or stakeholders, then the pipeline will be removed and disposed of according to a management plan to be developed and approved near the time of decommissioning. However, it may be presumed that the impacts of disinterring an empty gas pipeline would be higher than leaving it in place.
The offshore trunk and laterals will be cut at their respective beaches, flushed, capped and abandoned in place.

2.8.4.5 Onshore Reception/Metering Facilities

Equipment will be dismantled and removed for appropriate disposal according to a management plan to be developed and approved nearer the time. If required by the regulations in force at the end of the project lifetime, the concrete foundations will also be removed.

A contaminated land site assessment, commensurate with the level of risk, will be undertaken prior to site reinstatement works to ensure any contamination is not disturbed and spread throughout the site. If any contamination is discovered, a remediation program consistent with applicable Ghanaian standards will be prepared and implemented.

2.8.5 Decommissioning Wastes

Wastes include all solid building materials and equipment. All waste material will be sorted and material not deemed acceptable for reuse or recycling will be disposed of in an approved landfill site. Government agencies will be consulted on waste disposal matters during facility decommissioning and abandonment.

In preparing the decommissioning plan, Quantum will aim to demonstrate how it will reduce as far as practicable the amount of waste requiring disposal. This will include consideration of re-use and recycling alternatives where feasible, such as:

- Removal for use by another operator.
- Removal for sale to a third party.
- Leaving in place facilities or infrastructure of benefit to the community.

The decommissioning plan will also provide the procedures to be followed for the removal or making safe of the LNG terminal, equipment, structures and buildings.

The decommissioning contractor will designate waste management areas for segregation of the waste into re-use, recycle and disposal streams. Plant and equipment and components that are in good working order will be re-used, as appropriate. The decommissioning contractor will engage recycling contractors to collect all recyclable material and recycle and re-use as appropriate.

The hydrocarbon product to be processed will be predominantly gaseous, so soil contamination is not expected to be an issue. However, the decommissioning plan will provide for a soil contamination survey to be conducted to determine if there has been any inadvertent contamination (e.g. diesel fuel).

If any contamination is discovered, a soil remediation program will be developed and implemented consistent with regulatory requirements and good industry practice at the time of decommissioning.

2.9 ENVIRONMENT, HEALTH AND SAFETY MANAGEMENT

A series of activity-specific environmental, health & safety management (EHS) and protection measures will be developed and performance will be monitored against targets. EHS issues for the development of management and protection actions shall include those listed below.
2.9.1 Risk Mitigation

Events that constitute risks to the LNG terminal under the Project are:

- the collision of LNG tankers with other ships, or LNG tankers running aground;
- an LNG leak during unloading;
- an LNG leak from safety valves;
- major earthquakes; and
- Terrorist activity & sabotage.

The likelihood of these events must be minimised through strict application of rigorous standards in the design and operations of the terminal. If these events occur, their adverse consequences must be minimised through proper site of the facilities, and by institutionalizing a standard emergency response plan (ERP) and a disaster management plan (DMP). The Project will adopt these risk management measures. A Quantitative Risk Assessment (QRA) is required and will be developed to internationally recognised standards.

The initial Hazard Identification (HAZID) and Environmental Hazard Identification (ENVID) workshops were performed on the 19th & 20th August 2014, in Genesis offices at One St Paul's Churchyard, London, involving key project team members. This assessment was followed by a Hazard and Operability (HAZOP) workshop on the 27th & 28th of October, 2014 at Genesis offices in London. The HAZID and HAZOP studies form key part of the risk management process which are employed to ensure that the project health and safety risks comply with company expectations in that they are reduced to a level which is as low as reasonably practicable (ALARP). An initial assessment of the destructive impacts of a catastrophic loss of LNG shows no settlements would be affected.

Based on a model of discharge zones developed by Knight Piésold, the nearest settlements are well outside of the potential impact zone and, based on a preliminary evaluation, would not be affected by a catastrophic loss of LNG from the FSRU.

2.9.2 LNG Properties

To consider whether LNG is a hazard, it is appropriate to understand the properties of LNG and the conditions required in order for specific potential hazards to occur.

A comparison of the properties of LNG to those of other liquid fuels, as shown in Table 2-7, also indicates that the Lower Flammability Limit of LNG is generally higher than other fuels. That is, more LNG vapours would be needed (in a given area) to ignite as compared to LPG or gasoline. Methane gas will ignite only if the ratio or mix of gas vapour to air is within the limited flammability range.

In summary, LNG is an extremely cold, non-toxic, non-corrosive substance that is transferred and stored at atmospheric pressure. It is refrigerated, rather than pressurized, which enables LNG to be an effective, economical method of transporting large volumes of natural gas over long distances. LNG itself poses little danger as long as it is contained within storage tanks, piping, and equipment designed for use at LNG cryogenic conditions. However, vapours resulting from LNG as a result of an uncontrolled release can be hazardous, within the constraints of the key properties of LNG and LNG vapours – flammability range and in contact with a source of ignition – as described above.
Table 2-7: Comparison of Properties of Liquid Fuels

<table>
<thead>
<tr>
<th>Properties</th>
<th>LNG</th>
<th>Liquefied Petroleum Gas (LPG)</th>
<th>Gasoline</th>
<th>Fuel Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Toxic</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Carcinogenic</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Flammable Vapour</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Form Vapour Clouds</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Asphyxiant</td>
<td>Yes, but in a vapour cloud</td>
<td>Same as LNG</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Extreme Cold Temperature</td>
<td>Yes</td>
<td>Yes, if refrigerated</td>
<td>Eye irritant, narcosis, nausea, others</td>
<td>Same as gasoline</td>
</tr>
<tr>
<td>Other Health Hazards</td>
<td>None</td>
<td>None</td>
<td>Same as gasoline</td>
<td>Same as gasoline</td>
</tr>
<tr>
<td>Flash Point (°C)</td>
<td>-188</td>
<td>-104</td>
<td>-46</td>
<td>60</td>
</tr>
<tr>
<td>Boiling Point (°C)</td>
<td>-160</td>
<td>-42</td>
<td>32</td>
<td>204</td>
</tr>
<tr>
<td>Flammability Range in Air, %</td>
<td>5-15</td>
<td>21-95</td>
<td>13-6</td>
<td>N/A</td>
</tr>
<tr>
<td>Stored Pressure</td>
<td>Atmospheric</td>
<td>Pressurized (atmospheric if refrigerated)</td>
<td>Atmospheric</td>
<td>Atmospheric</td>
</tr>
<tr>
<td>Behaviour if Spilled</td>
<td>Evaporates, forming visible &quot;clouds&quot;. Portions of cloud could be flammable or explosive under certain conditions</td>
<td>Evaporates, forming vapour clouds which could be flammable or explosive under certain conditions</td>
<td>Evaporates, forms flammable pool: environmental cleanup required</td>
<td>Same as gasoline</td>
</tr>
</tbody>
</table>

2.9.3 Types of LNG Hazards

The potential hazards of most concern to operators of LNG facilities and surrounding communities flow from the basic properties of natural gas. As already described in the text above primary containment, secondary containment, safeguard systems, and separation distance provide multiple layers of protection. These measures provide protection against hazards associated with LNG. However, the following hazards are present with some probability of occurrence.

2.9.3.1 Explosion

An explosion happens when a substance rapidly changes its chemical state i.e., is ignited or is uncontrollably released from a pressurized state. For an uncontrolled release to happen, there must be a structural failure - i.e., something must puncture the container or the container must break from the inside. LNG tanks store the liquid at an extremely low temperature, about -256°F (-160°C), so no pressure is required to maintain its liquid state. Sophisticated containment systems prevent ignition sources from coming in contact with the liquid. Since LNG is stored at atmospheric pressure - i.e., not pressurized - a crack or puncture of the container will not create an immediate explosion.

2.9.3.2 Vapour Clouds

As LNG leaves a temperature-controlled container, it begins to warm up, returning the liquid to a gas. Initially, the gas is colder and heavier than the surrounding air. It creates a vapour cloud above the released liquid. As the gas warms up, it mixes with the surrounding air and begins to disperse. The vapour cloud will only ignite if it encounters an ignition source while concentrated within its flammability range. Safety devices and operational procedures are intended to minimise the probability of a release and subsequent vapour cloud having an affect outside the facility boundary.

2.9.3.3 Freezing Liquid

If LNG is released, direct human contact with the cryogenic liquid will freeze the point of contact. Containment systems surrounding an LNG storage tank, thus, are designed to contain up to 110 percent of the tank's contents. Containment systems also separate the tank from other equipment. Moreover, all facility personnel must wear gloves, face masks and other protective clothing as a protection from the freezing liquid when entering potentially hazardous areas. This potential hazard is restricted within the facility boundaries and does not affect neighbouring communities.

2.9.3.4 Rollover

When LNG supplies of multiple densities are loaded into a tank one at a time, they do not mix at first. Instead, they layer themselves in unstable strata within the tank. After a period of time, these strata may spontaneously rollover to stabilize the liquid in the tank. As the lower LNG layer is heated by normal heat leak, it changes density until it finally becomes lighter than the upper layer. At that point, a liquid rollover would occur with a sudden vaporization of LNG that may be too large to be released through the normal tank pressure release valves. At some point, the excess pressure can result in cracks or other structural failures in the tank. To prevent stratification, operators unloading an LNG ship measure the density of the cargo and, if necessary, adjust their unloading procedures accordingly. LNG tanks have rollover protection systems, which include distributed temperature sensors and pump-around mixing systems.
2.9.3.5 Rapid Phase Transition

When released on water, LNG floats - being less dense than water - and vaporises. If large volumes of LNG are released on water, it may vaporise too quickly causing a rapid phase transition (RPT). Water temperature and the presence of substances other than methane also affect the likelihood of an RPT. An RPT can only occur if there is mixing between the LNG and water. RPT ranges from small pops to blasts large enough to potentially damage lightweight structures. Other liquids with widely differing temperatures and boiling points can create similar incidents when they come in contact with each other.

2.9.4 Emissions Discharges and Waste

2.9.4.1 Air Emissions

Emissions to air will occur as a result of power generation on-board the FSRU to run the regasification process. Emissions will also occur from associated operations such as construction activities and support vessel traffic. Construction equipment used to construct the Facility will produce emissions to the atmosphere from the combustion of fuels such as diesel and gasoline. These gases include NO\textsubscript{x}, hydrocarbons, CO, PM, and SO\textsubscript{2}. These emissions are expected to be temporary and intermittent during the construction phase.

The main emissions generated by operation activities at the FSRU plant are particulate matter, sulphur dioxide, carbon monoxide, nitrogen dioxide and volatile organic compounds. Emissions are also generated from the LNG carrier and crew transport vessel.

2.9.4.2 Noise Emissions

The most unfavourable condition for generation of maximum noise emissions would be the use of Wärtsilä engines reaching levels of 124.6 dB(A). It is assumed that this type of engine would be used as part of the gas regasification system at the FSRU Plant. On the other hand, the highest emissions in the coastal zone are related to natural gas pressure regulation through the use of control valves at the metering station, which may determine emission levels between 82.3 dB(A) and 104 dB(A).

2.9.4.3 Wastewater Discharges

The project generates wastewater streams that will require treatment or suitable disposal. Potential effluent sources include the following:

- Storm water runoff;
- Accidental chemicals spills;
- Ballast water (from support vessels during construction); and
- Hydro-test water (during construction/commissioning).

During normal operation, no effluent streams are anticipated. The predominant wastewater discharge shall be hydrotest water during pre-commissioning. The construction vessels that lay the pipeline and install the PLEM will have to meet Ghanaian maritime legislation and this shall be the overall operator responsibility. This includes ballast water exchange discharge and compliance with MARPOL 73/78 which is referred to in the IFC effluent guidelines.

The FSRU will generate its own potable water using a small on-board desalination plant which will discharge an average of 50 cubic metres per hour of brine. The re-gasification system will involve the uptake of warm seawater for vaporising the LNG to natural gas and the discharge of...
cooled seawater back to the sea. In addition, there will also be discharge of warm water from the condensers.

**Hydrostatic Testing Water**

Hydrostatic testing of equipment and pipelines (both on and offshore) involves pressure testing with water (typically filtered seawater, unless equipment specifications do not allow it) to verify equipment and pipeline integrity. Chemical additives (corrosion inhibitors, oxygen scavengers, biocide, and dyes) may be added to the water to prevent internal corrosion or to identify leaks. In managing hydrotest waters, the following pollution prevention and control measures shall be considered:

- Minimizing the volume of hydrotest water offshore by testing equipment at an onshore site before the equipment is loaded onto the offshore facilities;
- Using the same water for multiple tests;
- Reducing the need for chemicals by minimizing the time that test water remains in the equipment or pipeline; and
- Careful selection of chemical additives in terms of dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential.

If discharge of hydrotest waters to the sea is the only feasible alternative for disposal, a hydrotest water disposal plan shall be prepared that considers points of discharge, rate of discharge, chemical use and dispersion, environmental risk and monitoring. Modelling using a risk-based approach should be considered to determine harm and the environmental risk. Hydrotest water disposal into shallow coastal waters shall be avoided.

**Sewage**

During operation, there will be a limited need for sewage treatment. The metering station is likely to be manned by a single security guard therefore will generate a small volume of domestic sewage. This shall be accommodated by sharing neighbouring facilities, or a septic tank shall be installed.

During construction, consideration shall be given to the grey and black water production from the workers both on and offshore. It is possible that crew replacement for the visiting LNG carrier may be performed in Ghana. In this case they will use the same service vessels that provide the FSRU. The FSRU will generated grey water (from showers, sinks, laundry, etc.) and sewage (from toilets). All effluent generated will be treated onboard before discharge at a rate of 8 m$^3$/day.

Vessels used during construction must comply with MARPOL 73/78b.

Annex IV of MARPOL 73/78 (regulations for the Prevention of Pollution by Sewage from Ships) and Annex V of MARPOL 73/78 (Regulations for the Prevention of Garbage from Ships) apply to all fixed and floating offshore installations and their support vessels. Annex IV of MARPOL 73/78 contains requirements to control pollution of the sea by sewage. The Annex applies to ships engaged in international travel that are of 400 gross tonnages and above or below 400 gross tonnage and certified to carry more than 15 persons. Schedule 2 of the Merchant Shipping Notice 1807 provides recommendations on standards for the rate of discharge of untreated sewage from ships, permissible outside of 12 nautical miles (nm) from land.

Annex V of MARPOL, implemented in the above regulations and those previously implemented in 1998 are applicable to every ship of 400 gross tonnage and above and any ship with more than 15 passengers, which must have a Waste Management Plan (WMP) in accordance with
IMO guidelines and those set out in Schedule 3 of Merchant Shipping Notice 1807. A Waste Record Book or equivalent must also be kept by all ships (within the thresholds set out already) engaged in voyages to ports or offshore terminals under the jurisdiction of other Parties to Annex V of MARPOL.

**Ballast and Bilge Water**

Ballast water will be required to meet the limit for effluent discharged into the marine environment. The MARPOL Convention pays particular attention to oil from machinery spaces of ships and de-ballasting operations and as Ghana has accession status to the MARPOL Convention; its provisions must be applied. Bilge water shall also be in compliance with MARPOL 73/78b as advised by the IFC regulations and therefore oil in water must remain within 15 parts per million (ppm).

Ballast water is controlled under the International Maritime Organization Resolution A.868 (20) “Guidelines for the control and management of ship’s ballast water to minimise the transfer of harmful aquatic organisms and pathogens.” This requirement is applicable for vessels coming outside of Ghana. Vessels coming outside of Ghanaian waters will be required to ensure a ballast management plan is in place to avoid the introduction of non-native species and identify suitable ballast exchange points prior to entering Ghanaian waters.

2.9.4.4 **Solid Waste**

Solid waste generated from construction will consist primarily of construction debris and domestic waste. Construction and domestic waste generated during the construction phase will include plastic, glass, cardboard, paper, packaging materials, metal containers and all waste generally associated with a construction office, warehouse, sanitation and dining hall, etc. These wastes will be collected onsite at central collection points for recycling or transported and disposed offsite in an approved landfill.

Solid waste generated during the operational phase of the LNG Project will consist of domestic and industrial waste characterised as either hazardous or non-hazardous. Domestic wastes generated during the operational phase will include plastic, glass, cardboard, paper, packaging materials, metal containers and all other waste generally associated with operating offices, warehouses, sanitary facilities kitchens and housing, etc. Non-hazardous industrial waste will be collected in properly labelled containers located at several designated areas of the plant. To the extent possible any materials will be reused or recycled. The non-hazardous waste that cannot be reused or recycled will be collected and transported by authorized transporters to an offsite recycler or landfill for final disposal.

Hazardous waste on project site, which will include spent oil, solvents, filters, containers, oily rags, mineral spirits, used paint cans, or any other materials contaminated with oil, solvents, paint, etc. will be stored in dedicated containers. These containers will be located in a concrete pad with a secondary containment and a collection sump with sufficient capacity to hold the volume of the largest volume container held in the containment area. The containment area will be fenced with a roof structure with open sides to allow for proper ventilation. To the extent possible these materials will be reused or recycled. The hazardous waste that cannot be reused or recycled onsite will be collected and transported by Ghanaian authorised transporters to their final destination for either destruction or treatment.