SAKARYA GAS FIELD DEVELOPMENT PROJECT – ENHANCEMENT OF SUBSEA PRODUCTION CAPACITY AND FLOATING PRODUCTION UNIT

Chapter 3 Project Description

COMPANY Doc. No. SC26-2A-OTC-PRJ-EN-REP-000006

04	25.10.2024	Issued as Final	WSP	TP-OTC	TP-OTC	
03	25.10.2024	Issued for Review	WSP	TP-OTC	TP-OTC	
02	21.10.2024	Issued for Review	WSP	TP-OTC	TP-OTC	
01	08.10.2024	Issued for Review	WSP	TP-OTC	TP-OTC	
00	29.08.2024	Issued for Review	WSP	TP-OTC	TP-OTC	
Rev. N°	**Date**	**Issue Type**	**Prepared by**	**Checked by**	**Approved by**	**COMPANY Acceptance Code**
					Classification:	**Internal**

REVISION TRACKING TABLE		
Rev. N°	**Modification Description**	**Modified Page No.**
00	Issued for review	N/A
01	Issued for review	Entire document
02	Issued for review	Entire document - new data and client comments incorporated
03	Issued for review	Entire document - new data and client comments incorporated
04	Issued as final	N/A

Information Classification

Code	Description of Information Classification
PUBLIC	Information and data that may be shared without restrictions because it is unlikely to result in any harm if disclosed to outside parties. Permission to actually release information to the public must be obtained separately through External Affairs
INTERNAL	Information and data that may be freely shared with staff in Engineer, Client and Partners, and contracted companies and individuals bounded by confidentiality agreements.
RESTRICTED	Only 5-10% of document content with such information classification can be released by Document Owner (or with his delegation) to identified recipients.
CONFIDENTIAL	Information that is extremely sensitive, of the highest value to the company and individuals and intended for use by named individual(s) only.

Table of Contents

3.0 PROJECT DESCRIPTION 5

3.1 Project Background 5

3.2 Project Overview 13

3.2.1 Subsea Production System (SPS) 16

3.2.2 Subsea Umbilicals, Risers, and Flowlines (SURF) 20

3.2.3 Floating Production Unit (FPU) 20

3.2.4 Export Pipeline 42

3.2.5 Existing Components 55

3.2.6 Associated Facilities 56

3.3 Project Rationale 59

3.4 Project Parties 62

3.5 Project Schedule 64

3.6 Project Location and Land Ownership 66

3.7 Labor and Working Conditions 69

3.8 Camp Sites 70

3.9 Resource and Infrastructure Requirements 74

3.9.1 General 74

3.9.2 Construction Phase 75

3.9.3 Operation Phase 91

3.10 Emission, Wastewater and Waste 95

3.10.1 Construction Phase 95

3.10.2 Operation Phase 100

3.11 Field Life and Decommissioning 104

TABLES

Table 3-1: Outer Inspection Operations 54

Table 3-2: Other Inspection Operations 54

Table 3-3: Total Natural Gas Consumption Amounts in Türkiye by Years (Billion Sm^3) 60

Table 3-4: Project Main Contractors and Scope of Works 63
Table 3-5: Waste Management Facilities in Zonguldak 74
Table 3-6: Urban wastewater Management Facilities in Zonguldak 74
Table 3-7: Onshore Section Construction Materials and Estimated Quantities 75
Table 3-8: The Vessels to be Utilized During Construction Phase of Offshore and Coastal Crossing Sections 76
Table 3-9: Fuel Consumption Calculations of the Vessels to be used during Construction 79
Table 3-10: Equipment List 84
Table 3-11: Water Consumption Data for the Vessels to be used in the Offshore Section during the Construction Phase 86
Table 3-12: Summary of Indicative Water Use During Construction Phase 90
Table 3-13: Chemical Tanks on FPU 91
Table 3-14: Indicative Water Use During Operation Phase 93
Table 3-15: Sea Water Useage (FPU Operation) 94
Table 3-16: Discharges related with Pre-commissioning Activities of SPS, SURF, and Offshore Pipeline 96
Table 3-17: Wastewater Expected to be Generated During the Construction Phase and Planned Management Methods 98
Table 3-18: Project Specific Discharge Standards, issued by the MoEUCC 101
Table 3-19: Wastewater to be Generated During the Operation Phase and Management Methods (Onshore) 103
Table 3-20: Amounts of Different Types of Water to be Discharged (FPU Operation) 103
Table 3-21: Solid and Liquid Waste Generation from FPU Operation 104

FIGURES

Figure 3-1: Illustration of Split of the Phase 1 Route Sections 6
Figure 3-2: Phase 1 Development Schematic 7
Figure 3-3: Phase-3 Development Schematic 9
Figure 3-4: Site Location Map 10
Figure 3-5: Project Layout Map 11
Figure 3-6: SGFD Onshore Layout 12
Figure 3-10: Illustration of Subsea Production System 17
Figure 3-11: FPU arriving in Türkiye, prior to modification 20
Figure 3-12: Mooring Field Layout 21
Figure 3-13: General Layout of FPU 22
Figure 3-14: Overall Process Flow Diagram 26

Figure 3-15: Isometric View of the Flare Tower and the Location of Flare on FPU 40
Figure 3-16: Dredging and Temporary Storage Areas 44
Figure 3-17: A Typical Cofferdam (Source: Phase 1 EIA Report)...45
Figure 3-18: Backfill Process – Stage 1..46
Figure 3-19: Backfill Process – Stage 2..46
Figure 3-20: Image of Vessel to Be Used at Near Shore Dredging..47
Figure 3-21: Gas Export Pipeline Start and End Points Illustration 49
Figure 3-22: Sequence Pre-commissioning Activities on the Gas Export Trunkline System............................50
Figure 3-23: Production Infield Pipeline –Pre-commissioning Flowchart..52
Figure 3-24: Flow Diagram of the Gas – Onshore..53
Figure 3-25: BOTAŞ Phase 1 and Phase 2 Pipelines 58
Figure 3-26: Global Primary Energy Consumption Rates in 2022 59
Figure 3-27: 2023 Natural Gas Sectoral Consumption Distribution in Türkiye (%) 61
Figure 3-28: Share of Imported Natural Gas by Source Country in 2023...61
Figure 3-29: TP-OTC Project Organization Chart 63
Figure 3-30: Phase 2 (Project) Schedule..65
Figure 3-31: Nearest Settlements Map...67
Figure 3-32: Previous and Current Land Status of the Filyos Industrial Zone and TPAO Special Investment Zone 68
Figure 3-33: Locations of Camps & Offices 72

3.0 PROJECT DESCRIPTION

This chapter describes the design philosophy of the Project, the construction schedules and the characteristics of the Project stages (or Phases); Construction, Operation and Decommissioning. It also describes the principal materials, equipment infrastructure used for the construction, wastes and emissions and water consumption associated with the Project, and labour requirements.

3.1 Project Background

TPAO initiated the Sakarya Gas Field Development Project ("SGFD") to extract, transmit to the shore, process, and deliver to the national system the natural gas, which was discovered in Sakarya Gas Field, in the exclusive economic zone of Türkiye, off the Western Black Sea Region, and the natural gas reserves to be discovered through the ongoing exploration. Sakarya Gas Field Block C26 is located within the western Black Sea, approximately 170 km offshore from Filyos, Zonguldak, at a depth of approximately 2,200 m, within the Türkiye exclusive economic zone. TP-OTC has been responsible for the management and engineering, procurement, construction, and installation of the SGFD and its operation.

The SGFD investment involves three phases: Phase 1, Phase 2, and Phase 3, described in the following chapters:

Phase 1 – Existing Facility

Involves natural gas production with the subsea production system (SPS) from 10 wells in the Sakarya Gas Field. The gas is transported onshore through an approximately 170 km long, 16-inch (40.64 cm) diameter steel pipeline, processed at the Onshore Processing facility (OPF), and delivered to the Petroleum Pipeline Corporation (BOTAŞ), with a daily production capacity of up to 10 million standard cubic meters (Sm^3). The infrastructure for Phase 1, including the SPS, SURF (Subsea Umbilicals, Risers, and Flowlines), and OPF, has been installed. The first gas arrival onshore was achieved in 2023, with an initial production of 2.8 million Sm^3/day. Currently, the production capacity has reached over 6 million Sm^3/day.

Once processed at the OPF, the gas produced by the Sakarya Gas Field is measured at a Fiscal Metering Station (FMS) and offloaded to the national grid via a ~36 km onshore pipeline (i.e. BOTAŞ Western Black Sea Natural Gas Pipeline Phase 1). Both the FMS and the pipeline have been designed, constructed, and operated by BOTAŞ and, in line with the IFC Performance Standards definition, were considered as Associated Facilities to the Phase 1 in the Phase 1 ESIA.

Two of the Phase 2 wells will be connected to the existing (Phase 1) subsea production system (resulting in total of 12 wells) as shown in Figure 3-2 with red circle. The natural gas extracted from these wells will be transported to and processed in the Onshore Processing Facility (OPF).

The **national Environmental Impact Assessment (EIA)**, for larger capacity of national gas production than realized in Phase 1, was disclosed and approved in November 2021.

The **Environmental and Social Impact Assessment (ESIA, here in after referred to as the Phase 1 ESIA)** prepared in accordance with the IFC Performance Standards and the Equator Principles was disclosed in December 2022. Outcomes of the ESIA were integrated in TP-OTCs Management System. As such the TP-OTC has fully developed policy, plans and procedures, including mitigation and monitoring measures from the ESIA, for the Phase 1 of the SGFD.

The Phase 1 ESIA, Stakeholder Engagement Plan (SEP), Non-Technical Summary (NTS) and the LRP prepared for the Phase 1 of the SGFD can be found on the TP-OTC web site: https://tp-otc.com/en/sustainability/.

An E&S Assessment Report was prepared for the FMS and the BOTAŞ Western Black Sea Natural Gas Pipeline Phase 1 (BOTAŞ Phase 1 Pipeline), including a Corrective Action Plan for BOTAŞ to implement. A separate Biodiversity Action Plan was also developed. The land acquisition and livelihood impacts of the BOTAŞ Phase 1 Pipeline were addressed in TP-OTC's LRP.

Phase 1 of the SGFD consists of three main units, including:

- Subsea Production System (SPS)
- Onshore Processing Facility (OPF)
- Subsea Umbilicals, Risers, and Flowlines (SURF)

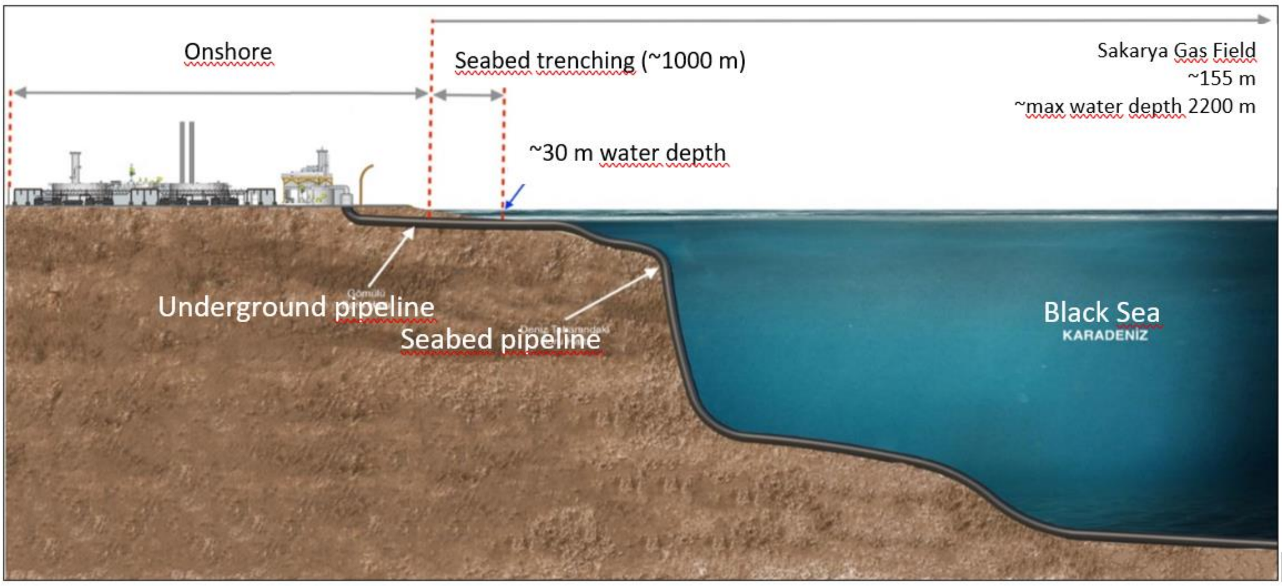

Figure 3-1: Illustration of Split of the Phase 1 Route Sections

The details of operation and components of these units are elaborated in the Phase 1 ESIA and summarised below:

Phase 1 Subsea Production System (SPS)

The existing SPS includes the necessary infrastructure for extracting natural gas from 10 wells located in the Sakarya Gas Field. This system comprises subsea trees (i.e. xmas trees), manifolds, and associated subsea equipment, all connected to the Onshore Processing facility through a network of subsea pipelines and control umbilicals. This setup facilitates efficient extraction and initial processing of the gas before it is transported to the OPF.

Onshore Processing Facility (OPF)

The Onshore Processing Facility (OPF), constructed in the Filyos Industrial Zone, processes the raw natural gas extracted from the Sakarya Gas Field to meet the BOTAŞ sales gas standards. The OPF includes various units for gas separation, particle filtration, dehydration, and compression to ensure the gas meets the specifications for delivery to the BOTAŞ network. The facility also features safety systems, control rooms, and other support infrastructure to manage and monitor gas processing operations effectively.

Phase 1 SURF

The SURF for Phase 1 includes a comprehensive network designed to transport natural gas from the SPS to the onshore processing facility. Key elements of this system include:

- **Main Export Pipeline:** This approximately 170 km long, 16-inch outer diameter steel pipeline transports the extracted gas from the subsea production system to the onshore processing facility in Filyos. The pipeline is designed and constructed in accordance with international standards to handle high pressures and is equipped with safety features to prevent leaks and ensure integrity.
- **Mono-Ethylene Glycol (MEG) Pipeline:** The MEG pipeline transports MEG from the OPF to the SPS, where it is injected into the gas stream to inhibit hydrate formation. This ensures that the flow of gas remains uninterrupted, and the pipelines do not become blocked by ice-like hydrates. The MEG pipeline is also approximately 170 km long and has an outer diameter of 10.0 inches. Like the main export pipeline, the MEG pipeline is designed and constructed in accordance with international standards for pressure integrity.
- **Subsea Umbilical:** A seabed umbilical, approximately 6 inches (15.24 cm) in outer diameter, bundles together small pipes containing fluids, chemicals, electrical, and fiber optic lines.

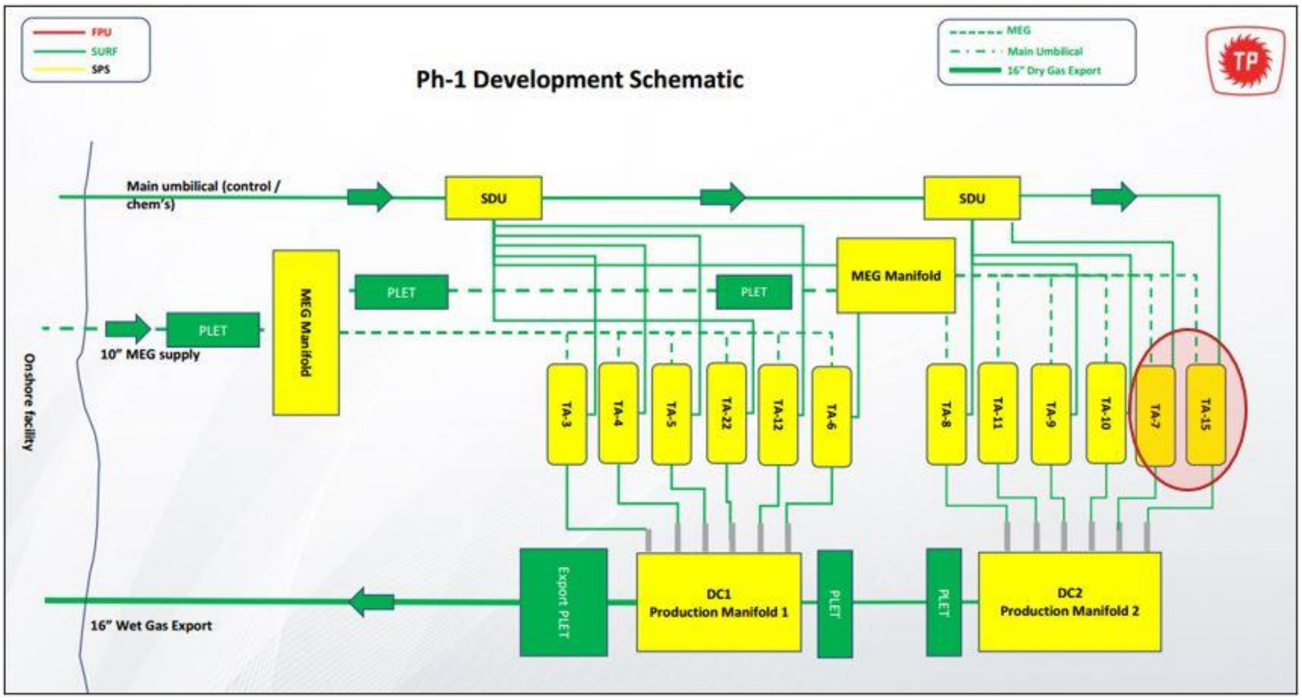

Figure 3-2: Phase 1 Development Schematic

Phase 2 (the Project):

This ESIA has been prepared for the Phase 2 of the SGFD.

A total of 13 additional wells are included in the Sakarya Gas Field Phase 2. Two of these wells will be connected to the existing SPS of the Phase 1. The natural gas extracted from these two wells will be transported to and processed in the OPF.

The other eleven wells will be connected to a new subsea production system to be installed, and the gas will be processed within a floating production unit (FPU). The processed, dried gas in the FPU then will be transported to onshore through an approximately 170 km long, 16-inch (40.64 cm) outer diameter steel dry gas offshore export pipeline and delivered to BOTAŞ through a tie-in in the onshore. Phase 2 aims to increase the total maximum raw gas production capacity up to 20.5 million Sm^3/day, by adding 10.5 million Sm^3/day to the existing capacity.

Due to the addition of the FPU's, TP-OTC initiated the **national Environmental Impact Assessment (EIA)** process, for a wider scope including i) the FPU and the offshore pipeline planned for Phase 2, ii) additionally a second FPU and a potential third offshore pipeline within the EIA boundary, that may be planned for the Phase 3.

The process was initiated by submitting the EIA Application File to Republic of Türkiye Ministry of Environment, Urbanisation and Climate Change (MoEUCC) in July 2024. The EIA Application File refers to the Project as "Sakarya Gas Field Subsea Production Systems, Subsea Transmission Line and Onshore Gas Processing Facilities Integrated Project Revision, and Addition of Floating Production Units". An EIA boundary has been determined within the scope of EIA Report and the EIA boundary is shown in Figure 3-5. The EIA Report will be assessed within the scope of the following articles from Environmental Impact Assessment Regulation (Official Gazette Date: 29.07.2022 Issue: 31907):

Annex-1 (List of Projects will be Implemented Environmental Impact Assessment)

Article 26: "Extraction of 500 tons/day of crude oil, 500,000 m^3/day of natural gas or shale gas"

Annex-2 (Projects Subject to Preliminary Environmental Impact Assessment and Evaluation)

Article 28-f: "Dredging projects planned to extract 50,000 m^3 or more of material"

Article 28- i: "Deep sea discharge projects"

Article 40: "Industrial facilities established to obtain electricity, gas, steam and hot water, (Those with a total thermal power of 20 MWt - 300 MWt)"

The Public Participation Meeting, required to be held within the scope of the national EIA process was held on 08th of August 2024. This meeting allowed TP-OTC to describe the activities that will be held within the scope of Phase 2 and Phase 3 to its stakeholders. Also, government agencies have been informed about the SGFD Phase 2 and the EIA Processes.

Phase 3:

TP-OTC plans to continue natural gas production in the Sakarya Gas Field by drilling approximately 44 additional wells and processing the extracted gas using a new Floating Production Unit (FPU) as shown in Figure 3-3. This phase aims to bring the total number of wells to around 67 across all planned phases, with a projected maximum raw gas production capacity of 46.5 million Sm³/day. Currently in the design stage, Phase 3 is expected to commence in parallel to Phase 2 execution.

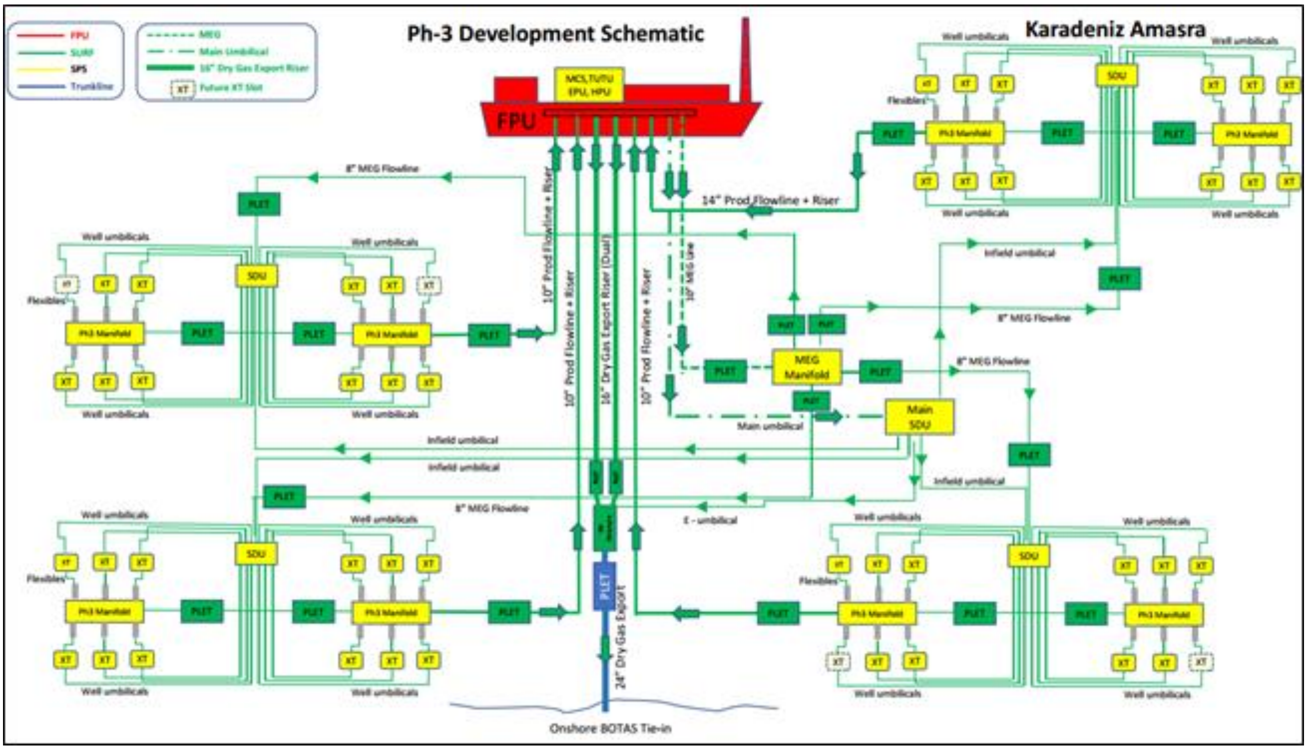

Figure 3-3: Phase-3 Development Schematic

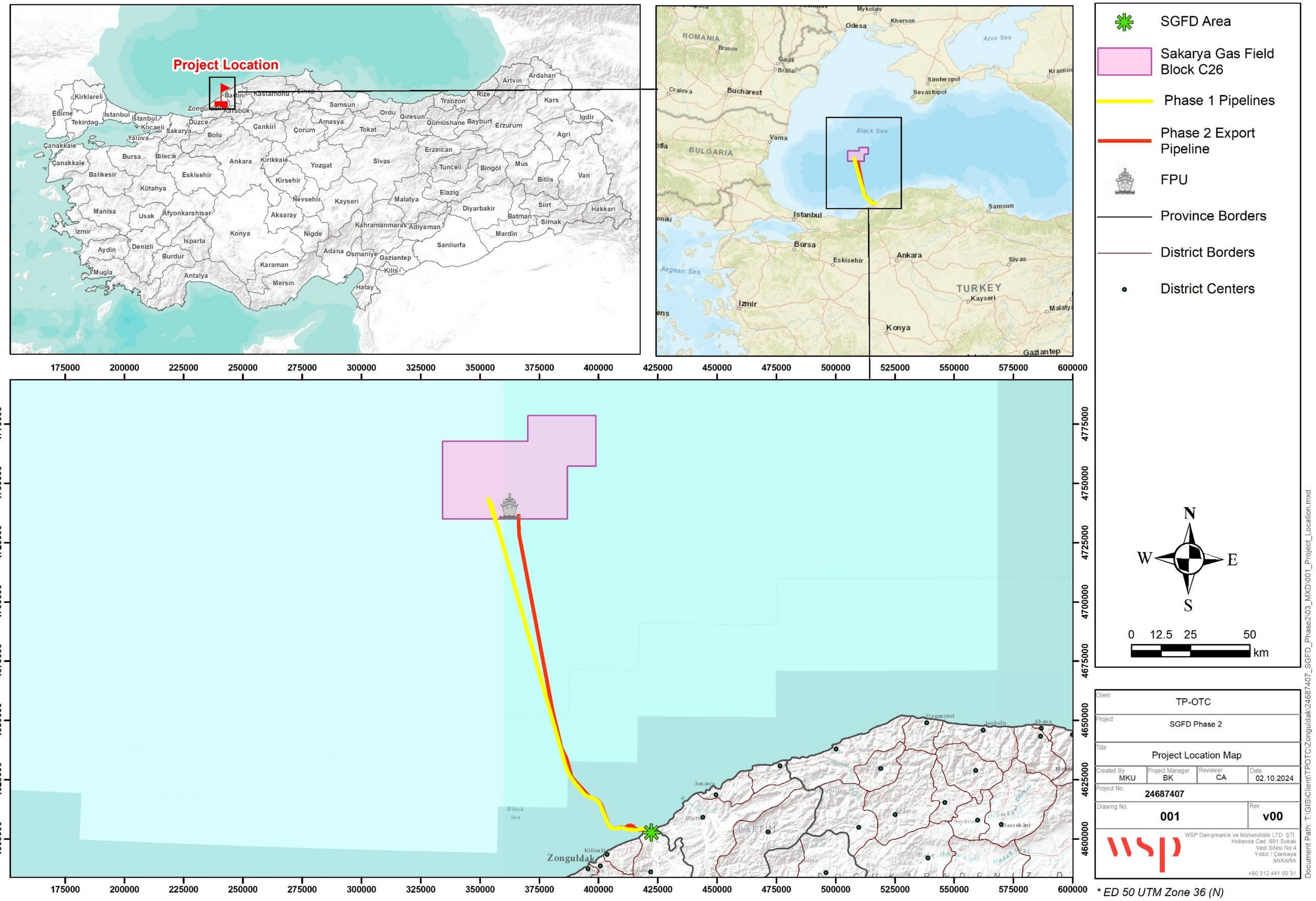

Figure 3-4: Site Location Map

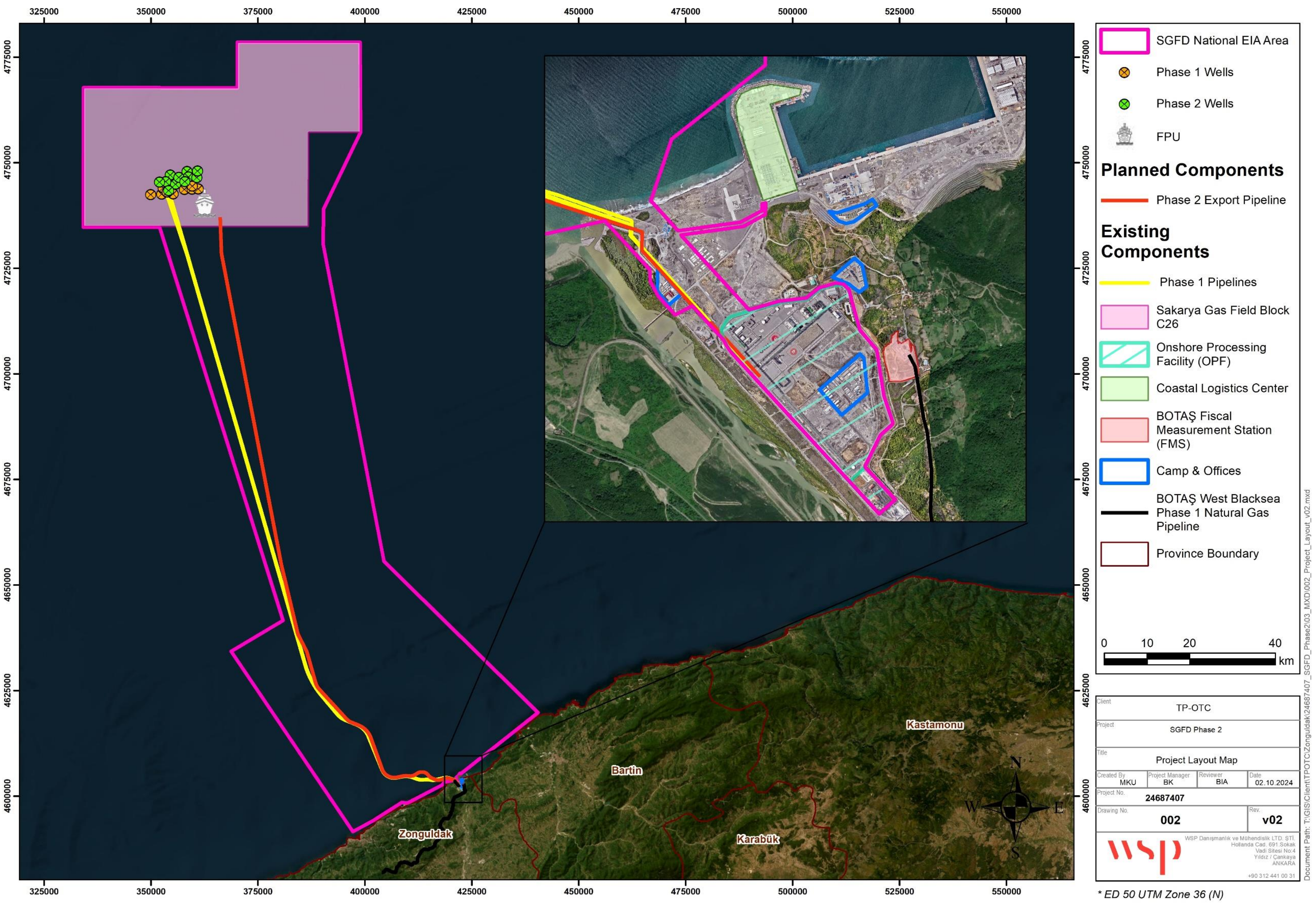

Figure 3-5: Project Layout Map

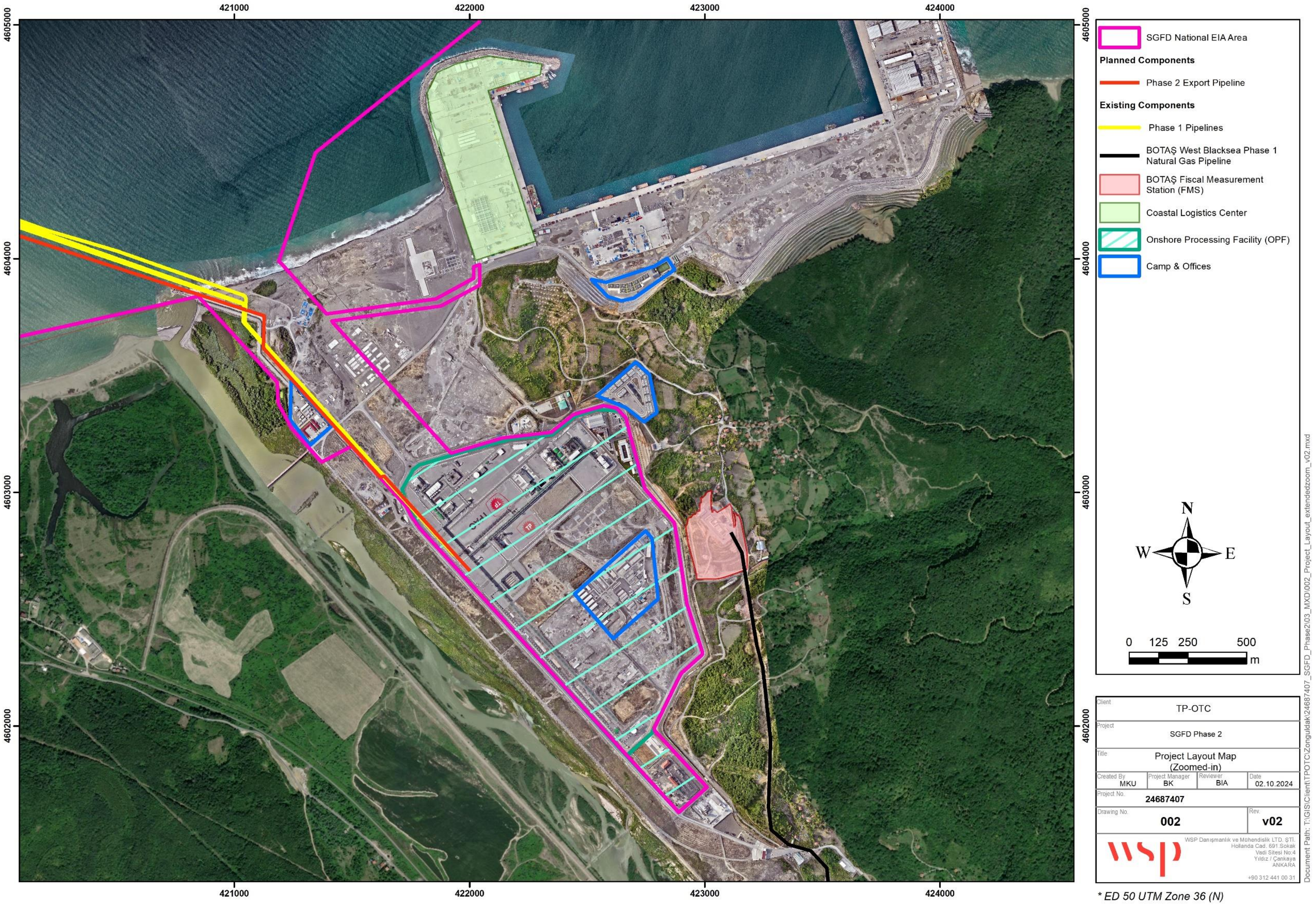

Figure 3-6: SGFD Onshore Layout

3.2 Project Overview

The scope of the ESIA for SGFD Phase 2 includes the SPS, SURF, FPU and the new offshore export pipeline to be built. Similar to the Phase 1 ESIA, the wells are classified as “other facilities” and are included in the ESIA at the cumulative impact level.

The Project location map is presented in Section 1 Figure 1, Project Layout is presented in Figure 3-5.

The Project (Phase 2) consists of four main units:

- Subsea Production System (SPS),
- Subsea Umbilicals, Risers, and Flowlines (SURF),
- Floating Production Units (FPU), and
- An export pipeline for the transportation of processed gas to the onshore connecting to the tie-in point with the BOTAŞ onshore natural gas grid.

Two of the Phase 2 wells will be connected to the existing (Phase 1) subsea production system as shown in Figure 3-2 with red circle. The natural gas extracted from these wells will be transported to and processed in the Onshore Processing Facility (OPF).

Within the scope of the Project (Phase 2), the natural gas extracted from the Phase 2 wells will enter the new SPS, which controls, measures, and consolidates the gas flow. The produced fluid stream, including natural gas, will then be directed into subsea flowlines, which are part of the SURF system. In the SURF, subsea flowlines will carry the stream horizontally from the manifold to the risers, which will then transport the stream vertically to the FPU moored permanently at the field. After reaching the FPU, the fluid stream will undergo further processing within the topside equipment system to remove water, reclaim Monoethylene Glycol (MEG), and compress the dehydrated gas for transport to shore. The FPU process and compression will ensure that the export gas stream meets the BOTAŞ sales gas specifications and the required minimum arrival pressure to enter the onshore gas grid. The processed natural gas will then be transported onshore through a new approximately 170 km long, 16-inch steel dry gas export pipeline and connected to the tie-in point with the BOTAŞ onshore natural gas grid for further distribution. The number of wells will enter within the scope of Phase 2 may extend in the future. The representative schematic of the Phase 2 is presented in Figure 3-7 and Phase 2 extension option presented in Figure 3-8.

In addition, the Phase 2 development will install infrastructure to allow control of the Phase 1 subsea production system via a new umbilical from the FPU to a suitable tie-in location within the Phase 1 subsea controls infrastructure. The timing of establishing the actual connection between the new Phase 1 umbilical from the FPU and the Phase 1 SPS will be determined considering (amongst others) the condition of the Phase 1 umbilical from shore, and the potential impact and risk to Phase 1 production and FPU operations. The new umbilical interconnection will allow communication between the FPU and OPF via fibre optic cable through the existing Phase 1 umbilical. In the future (i.e., not in the base case), production from the Phase 1 wells may be routed to the FPU, and/or the provision of MEG to the Phase 1 wells may be managed by the Phase 2 FPU. Furthermore, the Phase 1 production flowline may be used as an export line from the FPU to the OPF.

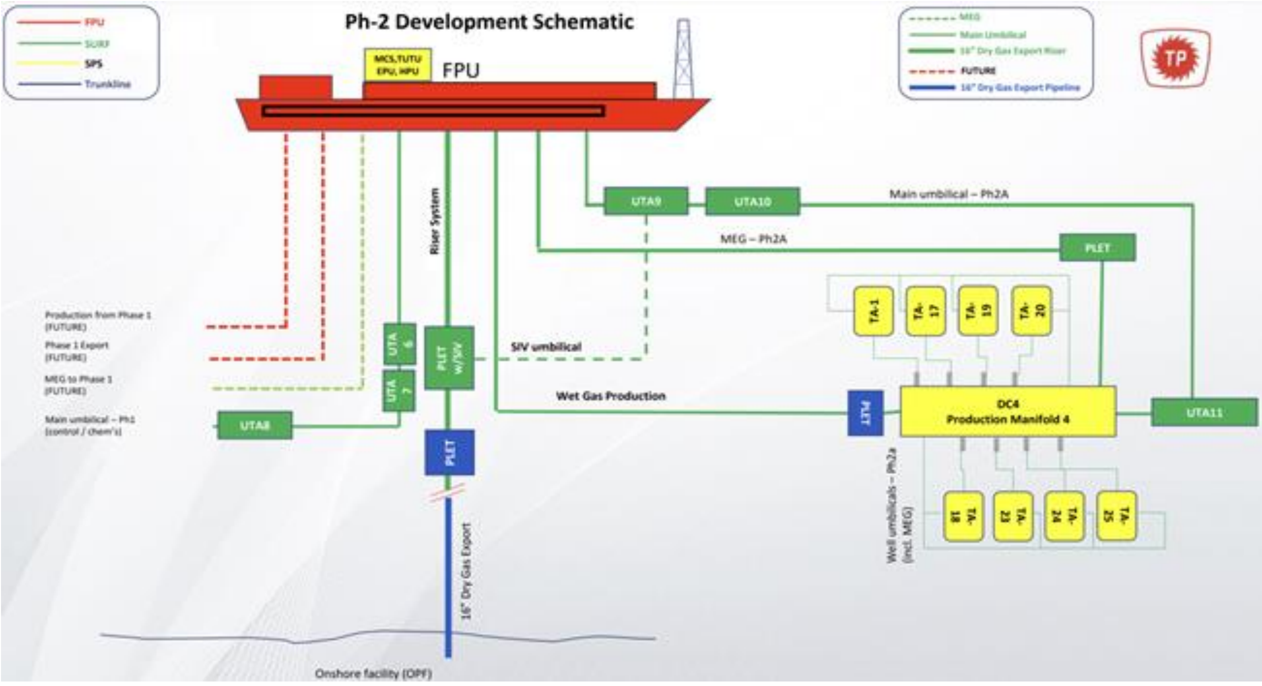

Figure 3-7: Phase-2 Development Schematic

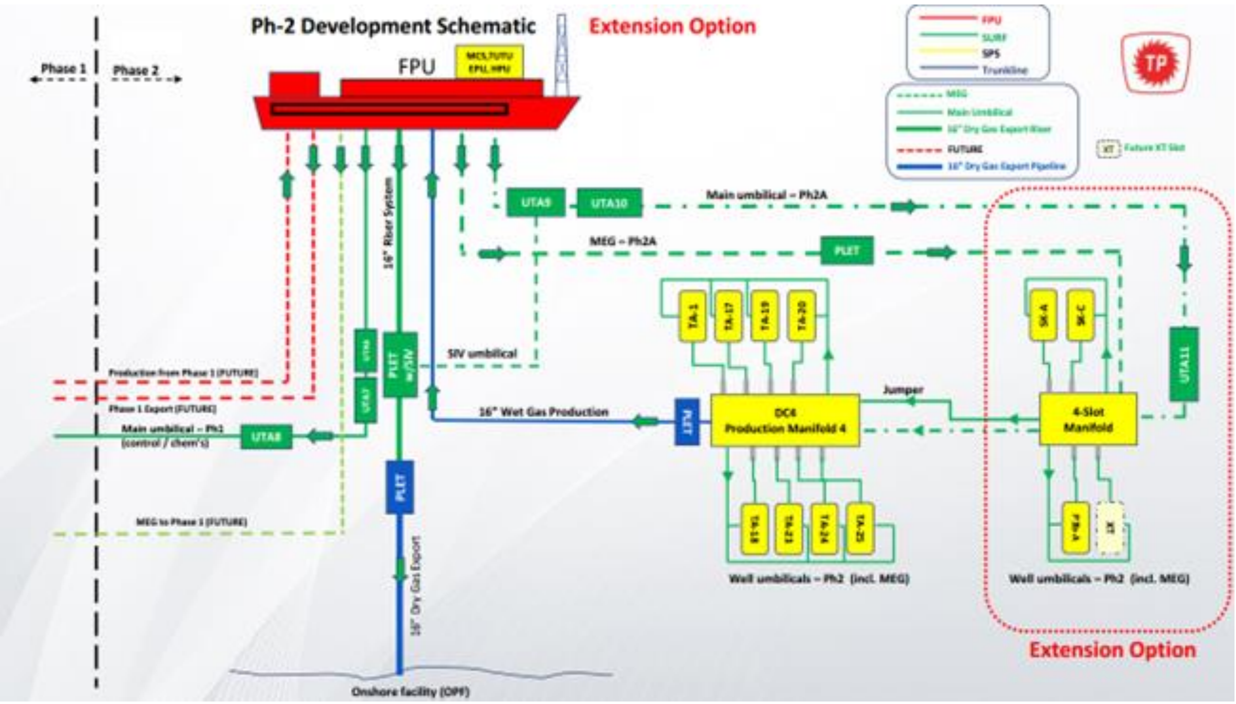

Figure 3-8: Phase-2 Development Schematic with Extension Option

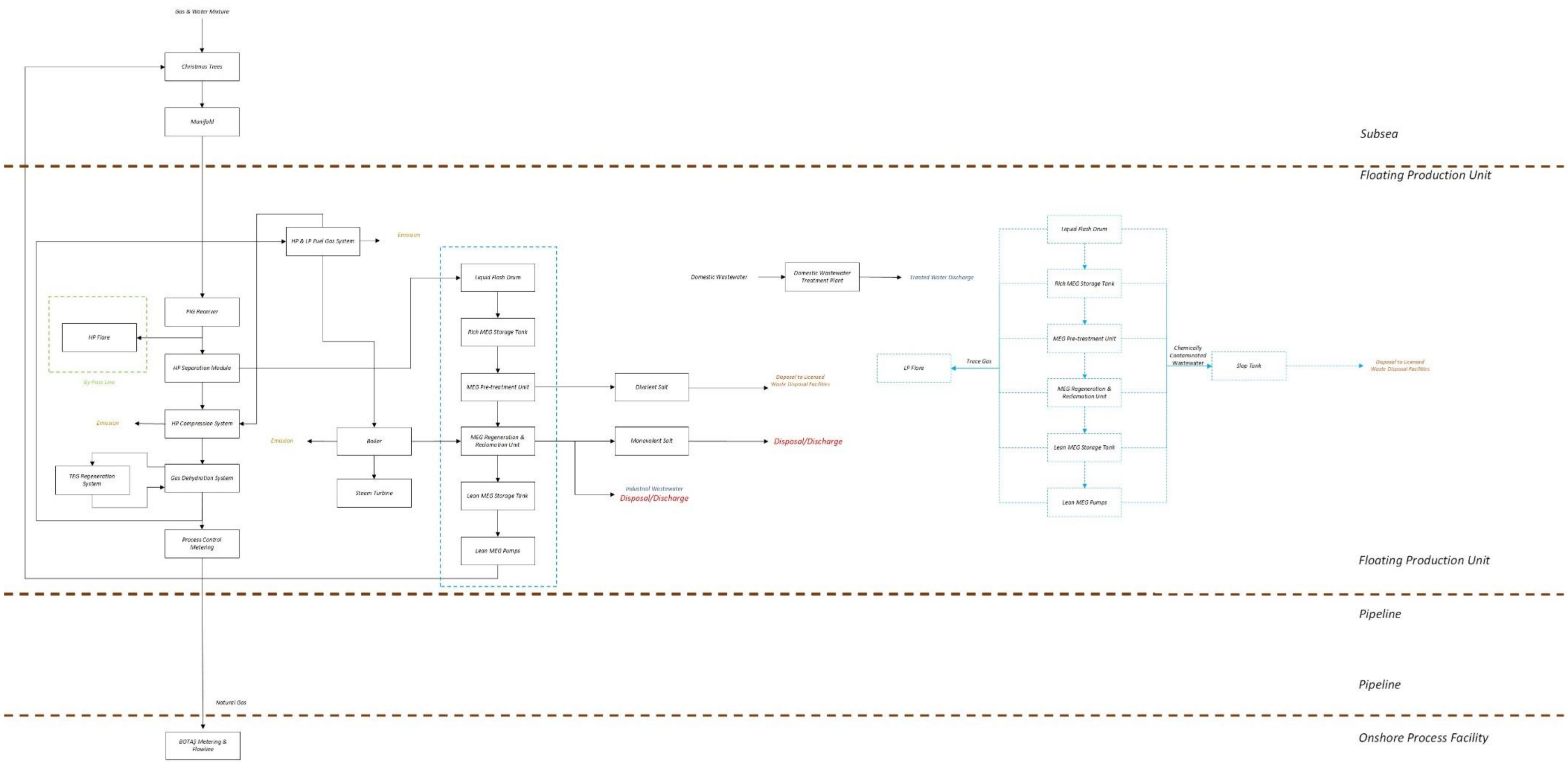

Figure 3-9: The Flow Process Chart of Phase 2

3.2.1 Subsea Production System (SPS)

A new SPS for Phase 2 will be installed to control the production flow of natural gas extracted from 11 new subsea wells. The SPS will include subsea equipment such as wellheads, Xmas trees (XT, valve assemblies placed on top of the wellheads), a production manifold, and control systems. These components will work together to control and measure the extraction process.

Wellheads and Xmas trees will be installed on the seabed, providing the necessary interface for extracting natural gas from the reservoirs. The wellheads serve as the termination points for the wells, allowing for the management of production, injection, and monitoring activities. Xmas trees, which include valves and control mechanisms, will enable operators to regulate the flow of gas and fluids during extraction.

The production manifold will collect the extracted gas and water liquid streams from multiple wells and direct them into the flowlines of the SURF system for further transport and processing. It will facilitate the distribution of fluids to the appropriate flowlines while ensuring efficient management of production from all connected wells. The production manifold also contains piping for receipt of MEG from the FPU and further distribution to the individual wells.

Control systems will remotely monitor and adjust operations to maintain optimal flow conditions and ensure safety. These systems will incorporate various sensors and instrumentation to track parameters such as pressure, temperature, and flow rates, allowing for real-time data analysis. Primary control of the Phase 2 subsea wells will be from the Phase 2 FPU control room.

Figure 3-10 illustrates the subsea production system.

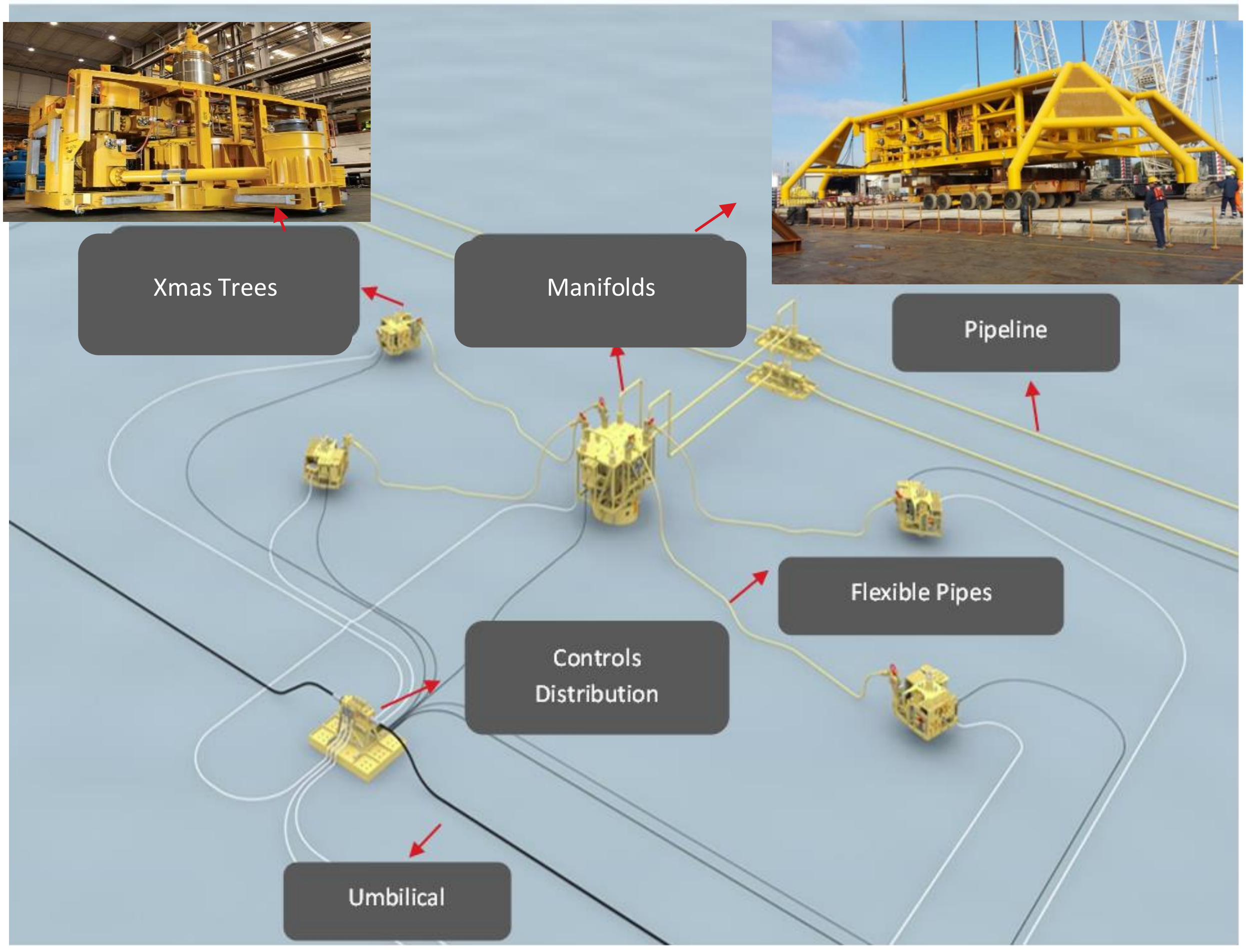

Figure 3-10: Illustration of Subsea Production System

Construction Phase

Construction involves the below actions:

Well Completion and Installation of Xmas Trees (XTs)

The XTs will be maintained at the Filyos Port before their installation. XTs will be transported to the site by the Platform Supply Vessel (PSV) in accordance with the approved procedures.

The XTs will be connected to the wellheads, which have been installed at the seabed by the mobile offshore drilling ship as part of the well drilling operations. The XTs will be operated and tested on-site to ensure integrity with the well heads. Following a successful test, the well completion works will be finalized by installing upper completion gear and subsequent backflow cleaning procedures. The primary goal of the well completion is to prepare the well to produce hydrocarbons through the SPS. Smart completion valves, which can control reservoir zones, will be installed during the upper completion. After the system has been successfully tested, the correct flow will be supplied to the mobile offshore drilling vessel to clean and test the well. The remaining connections will then be completed by the subsea installation vessels to prepare the well for production.

Installation of Production Manifold and Subsea Distribution System Components

Due to soft, low strength seabed sediments in the region where the gas production and MEG distribution manifolds will be installed, a foundation for these units will be installed by erecting suction piles at defined locations within the gas production field. Subsequently, the distribution manifolds will be installed on the pre-installed suction piles. The suction pile foundation for MEG manifold will be approximately 87 tons in weight, 12 m in length and 6 m in diameter. The supply ships or cargo barges will transport the suction piles to the field. Other components of the SPS will be installed on seabed directly. The heave compensation system will be activated to prevent any impact on installation winch of the crane from wave movements during installation of the equipment onto the seabed. Furthermore, monitoring with a Remotely Operated Vehicle (ROV) will ensure the launched material to be properly positioned.

The location, slope, elevation and coordinates of the distribution manifold will be recorded once it has been placed.

After all components of the subsea distribution system are installed, they will be connected to the XTs and tested.

Installation of Carbon Steel Pipelines

Carbon steel pipelines are the assemblies that allow the flow of gas and MEG between the distribution manifold and the FPU.

Pipelines shall be terminated on seabed with pipeline end termination units (PLET), which shall be connected to corresponding built-in hubs on the production manifolds with tie-in spools. Installation of tie-in spools will be by use of special tools, driven by hydraulic power by the ROV. The ROV will continuously monitor the operation to ensure that the tie-in spools are in the proper position and aligned with the pipeline system. The seal tests will be done after the tie-in spools are installed and connected to check that the gaskets in the joint are properly sealed.

Other Seabed Foundations

Prior to installation of other key subsea production system components, such as control distribution units, umbilical termination units, and similar, the mudmats will be located on seabed as foundation. Mudmats are the flat steel structures used as base for these units.

Installation of Flexible Pipes

The gas produced will be transferred from the XT to the distribution (production) manifold by means of flexible pipes. Similarly, the MEG that will be supplied to the production manifold and will be transported by means of tubes within the well umbilicals by to the individual XTs. Flexible pipes will have flanged joint ends. Specialized flexible pipe construction vessels will undertake the installation.

The flexible pipe interface consists of standard flanged end joints, pre-connected flexible pipes, externally inserted vertical connectors as well as hoisting interface and gooseneck assemblies. Gooseneck assemblies will be stored and transported separately from the flexible pipe. During assembly, they will be connected to the flexible ends in the piping tower of the assembly ship.

Once the first end has been attached to the gooseneck flexible pipe, the flexible pipe will be laid on the seabed by using a reel lay system. When all the flexible pipe has been laid, the second end of the flexible pipe interface will be attached to the second gooseneck and laid on the sea bottom. The first end of the pipe will then be attached to the production distribution manifold and the dispatch end to the wellhead valve. Flexible piping activities will be checked by the ROV to be launched to the sea by support vessel. This will ensure that the laid flexible pipe remains inside the designated construction corridor. Final joints will be undertaken by using a subsea connection system.

Installation of Umbilical

The umbilical will be utilized to supply hydraulic fluid, MEG and necessary chemicals to the XTs. The umbilicals also contain cables for communication with and control of the wells.

The ROV will monitor the umbilical installed on the seabed.

The umbilical in the production field will be connected to the wellhead valves and seabed distribution manifolds following the completion of the installations.

Pre-commissioning Activities

Prior to commissioning, the structural integrity of the pipelines will be determined by flooding, cleaning and gauging activities in which the pig train will be launched and propelled with filtered and treated seawater. After the gauge plate acceptance, the flooding, cleaning and gauging (FCG) operation will be completed. Subsea flooding spread will be operated from support vessel. For hydrotesting (H), subsea hydrotest pump will be engaged and the pipeline will be pressurized. Stabilization period (2 hrs) will start followed by hold period (8hrs). After validation of the hold period, the pipeline will be depressurised to ambient pressure. Subsea leak test which is similar to hydrotesting will follow afterwards.

Discharges related with pre-commissioning activities are presented in Section 3.9.2.4 and 3.10.1

Operation Phase

The main parts of the production system planned to be installed on the subsea are

- the XT's placed on top of the wellheads where production control and measurement connections for each well are made, and
- the distribution (production) manifolds placed to collects and controls the produced gas flow coming from wells and transfer it to the gas pipeline. It also distributes the MEG to the XTs.

The XTs located at each wellhead location allow controlling the wells. The XTs will be connected to the production distribution manifold with flexible pipes. The flexible pipes will deliver both the gas and the MEG.

The hydraulic fluid, MEG, electrical and fibre optic connection cables within umbilical will be used to control valves in the production system and to ensure the safe flow of gas.

MEG will be comingled with the gas during the transportation of the produced gas to FPU in order to prevent the formation of hydrate, which may block the pipe under certain pressure / temperature conditions. The MEG will be transported to the manifold through a pipeline from FPU and infused into the gas by injecting it into the well heads. Thereafter, it will turn back to FPU mixed with gas through the risers and flowlines.

3.2.2 Subsea Umbilicals, Risers, and Flowlines (SURF)

Within Phase 2, a new SURF system will be installed to provide the infrastructure for transporting extracted gas and water liquid streams from the SPS to the FPU. The SURF system will consist of subsea flowlines, risers, a monoethylene glycol (MEG) line from the FPU to the manifold, a main umbilical between the FPU and the manifold, and well umbilicals for MEG injection.

Subsea flowlines will transport the gas horizontally from the manifold to the risers. The risers will accommodate the vertical movement of the gas, facilitating its transport from the seabed to the surface facilities on the FPU.

The MEG line will connect the FPU to the manifold, supplying MEG to prevent hydrate formation in the gas during extraction and transportation.

The main umbilical will connect the FPU and the manifold, enabling the transmission of electrical power, hydraulic control, and communication signals. This setup allows for monitoring and remote operation of the subsea systems, supporting production operations.

Well umbilicals will connect the manifold to the individual subsea wells, facilitating the injection of MEG and other necessary fluids.

3.2.3 Floating Production Unit (FPU)

A Floating Production Unit (FPU) will be used to process the extracted natural gas to meet the BOTAŞ sales standards before exporting it to the onshore via export pipeline.

Figure 3-11: FPU arriving in Türkiye, prior to modification

The FPU that will be used in the Project is an existing very large crude carrier (VLCC) size trading tanker that was converted to a floating production storage and offloading (FPSO) unit in 2008/2009 and operated in Brazil from 2009 until 2015. The FPSO will be re-designated to an FPU and will be refurbished and modified and re-deployed to the Black Sea to suit the Sakarya Gas Field for operations in a water depth of approximately 2,200 meters.

The FPU vessel has arrived in Çanakkale in September 2024. The modification is anticipated to take up to 2 years in total of which first year will be in Shipyard in Çanakkale and then the 2nd year will be in Filyos Port for new module installation, integration and onshore commissioning and will be planned to depart from Filyos port in 2nd half of 2026 to location to hook up and offshore commissioning at Sakarya Gas Field.

Once the necessary topside equipment is installed, the FPU will arrive and be moored at the Sakarya Gas Field. After completing the construction of the production system (including the SPS, SURF, and export pipeline) and connecting to the FPU, the natural gas processing will commence.

The mooring system comprises of 20 off mooring piles, chains, polyester ropes and connectors. The work to be completed is to pre-lay 20 mooring lines, tow to field the FPU and hook up 20-off mooring lines to FPU (5 mooring lines for each group) as shown in the below figure.

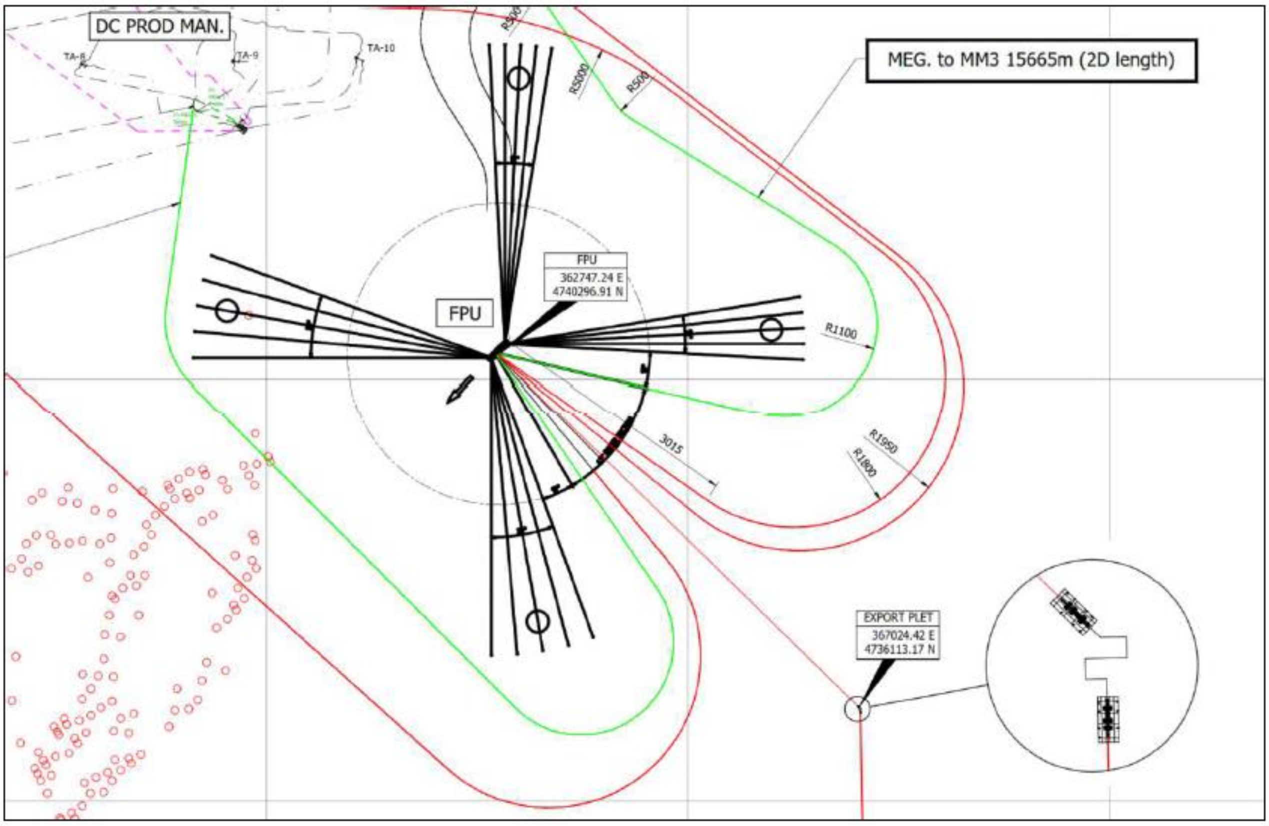

Figure 3-12: Mooring Field Layout

FPU is designed for autonomous operation at the Sakarya Gas Field, with a design life of 20 years. It will serve as a standalone offshore unit capable of gas processing and housing personnel, ensuring continuous operation without the need for external power or crew habitation facilities.

The living quarters on the FPU are designed to accommodate 140 personnel and will function as a Temporary Refuge (TR) to provide safe areas in the event of emergency. These quarters will include facilities for dry and cold food storage sufficient for approximately 14 days, with normal supply vessel frequency expected to be at least once per week.

Utilities to support FPU operations will include systems for generating fresh water from seawater, handling grey and black water to meet MARPOL requirements, and storage facilities for consumables and chemicals. The FPU will have storage capacity for 14 days' worth of Marine Gas Oil (MGO), fresh water, and production chemicals, and 14 days' worth of MEG and MEG chemicals based on peak demand.

Logistical support for the FPU will be provided through platform supply vessels (PSVs) and helicopters, ensuring the continuous supply of goods, consumables, and personnel. PSV operations are planned to occur once per week, with the possibility of increased frequency to handle high divalent salt from MEG reclamation. Helicopter operations are expected to occur three times per week, with the FPU designed to accommodate larger helicopters in the future. During offshore hook-up and maintenance shutdowns, the FPU will utilize its full 140-person capacity, necessitating more frequent helicopter and supply boat operations.

The representative layout of the FPU vessel is presented in Figure 3-13

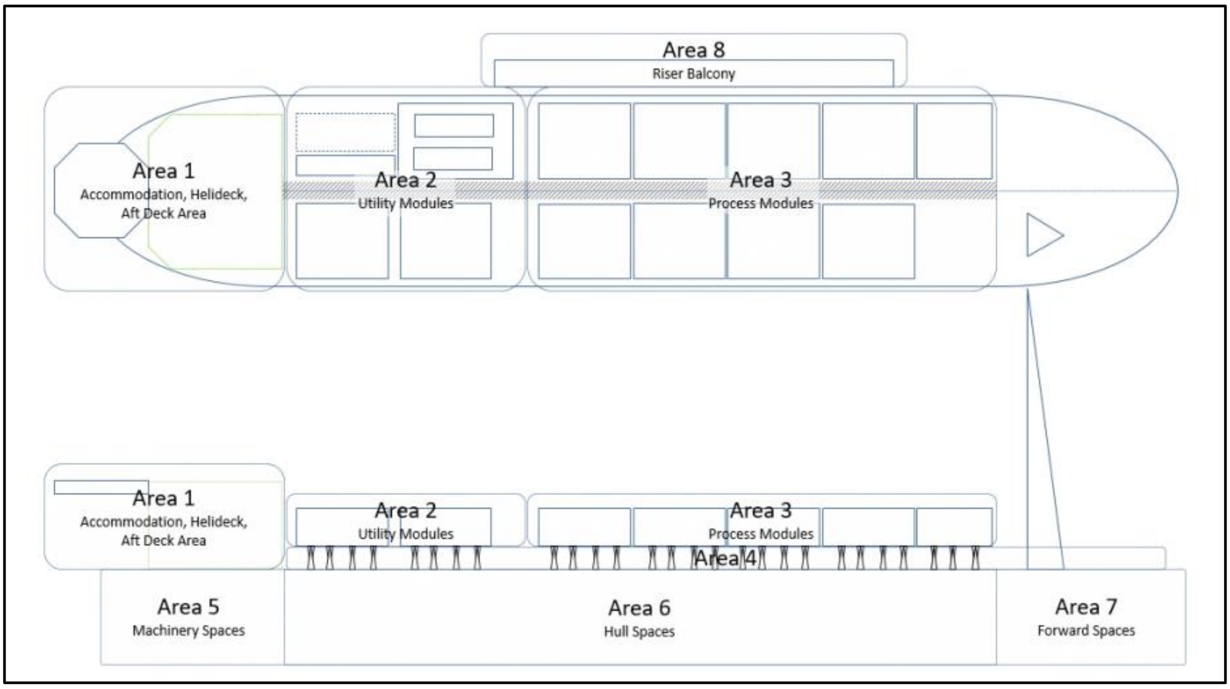

Figure 3-13: General Layout of FPU

3.2.3.1 Hull and Structural Facilities

The FPU hull features various tanks including those for Rich and Lean MEG, Sodium Carbonate, Sodium Hydroxide chemicals, ballast, slops, Marine Gas Oil (MGO), and void tanks. It is equipped with a 140-persons Living Quarters (LQ) that includes Temporary Refuge (TR) facilities and a helideck. The LQ also contains amenities, offices, and cabins. Additionally, the Engine Room/Accommodation block houses Marine and Electrical Instrumentation Telecommunications (EIT) equipment.

3.2.3.2 Accommodation Facilities

The FPU is equipped with accommodation structure designed to provide a safe and comfortable living environment for up to 140 personnel. The accommodation layout is organized around a central circulation core with symmetrical secondary escape routes, facilitating quick evacuation recognition and efficient movement in emergency situations.

Each deck features a repeat layout pattern to ensure familiarity and ease of evacuation. The structure is fully air-conditioned and includes facilities for company personnel, catering staff, operations, maintenance crews, and other support services.

The accommodation provides various essential and recreational facilities, including:

- Offices
- Galley and Mess Rooms
- Recreational Rooms
- Media Rooms
- Various Stores
- Hospital
- Laundry
- Gymnasium
- A designated prayer room located in the aft area of portside D Deck

The hospital is outfitted to high standards, including a separate surgical room, consultation area, medical stores, and a designated ward area to meet all applicable health and safety requirements.

The accommodation is equipped with public address and general alarm speakers installed in alleyways and public spaces to ensure effective communication during emergencies. Each deck has a minimum of two exits, and the main muster station is located in the Mess Room on the starboard 1st Poop Deck.

The Temporary Refuge (TR) area is designed to maintain integrity during Design Accidental Events, providing protection from Major Accident Hazards (MAH) for the duration of the hazardous event or until complete evacuation is achieved. All accommodation entrances are located from safe area locations and feature air lock arrangements. Secondary exits from cabin decks are designated for emergency use only.

Evacuation procedures prioritize safety and efficiency, with the primary escape route being via helicopter. Muster procedures may be sequenced from the main internal muster area on the 1st Poop Deck, with secondary and tertiary escape routes adjacent to the muster area.

The cabins are available in multiple configurations, including single, dual, and four-man options. Each cabin is equipped with a private shower and toilet room, as well as smoke and fire detection systems.

A LAN Network is provided onboard to facilitate all data communication requirements, ensuring seamless connectivity and operational efficiency.

3.2.3.3 Machinery and Marine Systems

The machinery space accommodates the steam turbines and alternator, seawater lift pumps, cooling medium pumps and exchangers, steam deaerator, and various ancillary equipment to support the steam system. The FPU is equipped with marine systems for ballast, bilge, fuel, lubrication, seawater cooling, freshwater cooling, compressed air, and inert gas.

3.2.3.4 Power Generation and Auxiliary Systems

To support both habitation and gas processing on the FPU, it is equipped with its own power generation and auxiliary systems designed for continuous operation with suitable redundancy to ensure high availability. The power generation consists of single-fuel essential power generation using diesel generators and dual-fuel main power generation, which relies on steam boilers that supply steam for both power production and heat demand. This dual-fuel capability ensures that the FPU is fully self-sufficient in power generation, independent of external power sources. During normal operation when production is ongoing, the main power system operates on fuel gas, while the essential or main power generation will switch to liquid fuel if production is shut down and fuel gas is unavailable. The FPU is equipped with large marine gas oil storage tanks, with 98% of the capacity being 4,670 m^3, to store MGO for power demands.

Additionally, the FPU is capable of generating its own fresh water from seawater through freshwater makers, which includes potable water systems to support both operational and habitation needs. For the living quarters, grey and black water systems are also included to ensure that effluents to be discharged to sea comply with the latest MARPOL requirements.

3.2.3.5 Electrical Instrumentation Telecommunications (EIT) Facilities

EIT facilities encompass the E-House, switchgear rooms, transformer room, battery rooms, Central Control Room (CCR), Central Equipment Room (CER), and Telecom Equipment Room (TER). It also includes main, essential, and emergency power generation systems, Uninterruptible Power Supply (UPS) systems, lighting and small power systems, automation, Integrated Control and Safety Systems (ICSS), and telecommunications systems.

3.2.3.6 Safety Systems

Safety systems are integral to the FPU's design and include a Fire and Gas (F&G) system, active and passive fire protection systems, blast protection systems, lifesaving equipment, and evacuation and rescue systems such as lifeboats, life rafts, and fast rescue craft. Additionally, it features public address and general alarm (PAGA) systems and network security systems.

3.2.3.7 Miscellaneous Systems

The FPU also includes various other systems such as a laboratory, stores, and workshops, ensuring a well-rounded and functional facility.

3.2.3.8 Topside Facilities and Process Overview

The topside facilities are designed to receive production fluids from subsea systems and send export gas to shore. These facilities include onboard process systems such as separation, dehydration, gas compression, MEG reclamation, triethylene glycol (TEG) regeneration, and chemical injection. Utility systems onboard provide heating and cooling medium, plant and instrument air, nitrogen, fuel gas, blowdown and flare, as well as open and closed drains. The FPU also includes subsea Hydraulic Power Unit (HPU) and Topside Umbilical Termination Assembly (TUTA), laydown areas, and various hull and topside equipment/modules located on the main deck.

The topside equipment of the FPU is designed for a gas export flow rate of 10 million Sm^3/day, along with handling Rich MEG recovery rates of 1,502 Sm^3/day. Since the maximum throughput of the gas compression train is 10 million Sm^3/day, fuel gas is extracted upstream of the compression system. As a result, the inlet separation facilities are designed to handle 10.5 million Sm^3/day to account for fuel gas consumption. MEG is used as the primary hydrate inhibitor on this FPU and is continuously injected at the subsea wells.

The FPU will operate in two phases: High Pressure (HP) for the first five years and Low Pressure (LP) for the remaining fifteen years. During the HP phase, the subsea production system will deliver gas to the FPU inlet at 110 barg, while in the LP phase, the delivery pressure will be reduced to 40 barg. Simultaneous operation of HP and LP modes is not expected, and the design is based on operating either in HP Mode or LP Mode.

Produced fluids arriving at the FPU are separated into gas, which is then compressed, dehydrated, and exported via the gas export pipeline. The Rich MEG stream, separated either at the inlet facilities or the LP Inlet Separator (depending on the mode of operation), is channelled to the LP Test Inlet Separator, which is repurposed as a flash vessel. The outlet liquid stream then enters the MEG recovery unit. This MEG recovery unit can handle 1,502 Sm^3/day of Rich MEG (at 43.3% wt) to produce 743.7 Sm^3/day of Lean MEG (at 85% wt). The regenerated Lean MEG is then reinjected back to the subsea wells through a dedicated MEG riser, forming a closed-loop system. The overall process diagram is shown in Figure 3-14.

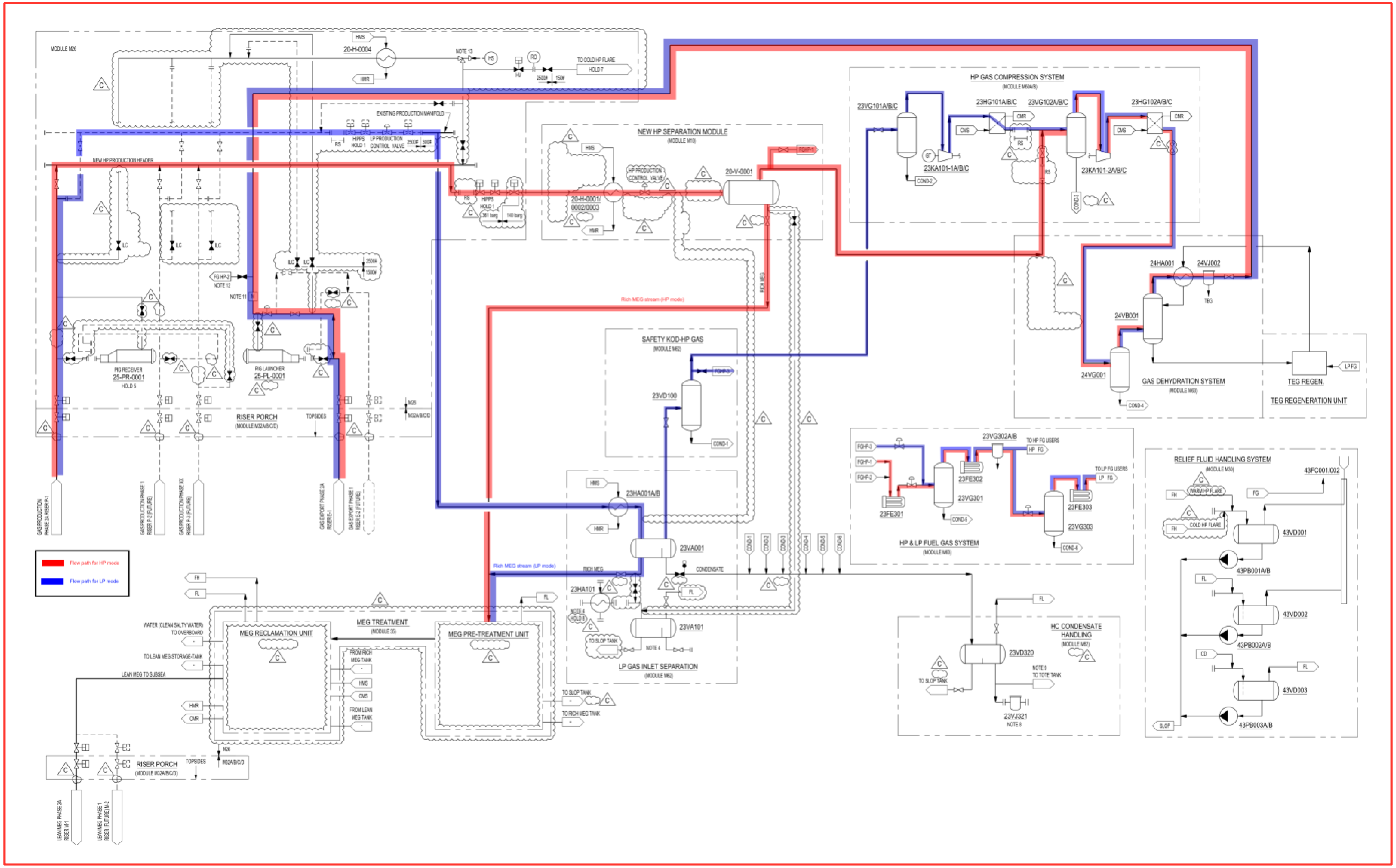

Figure 3-14: Overall Process Flow Diagram

Due to differences in arrival pressures arising from natural reservoir depletion over time, the FPU operations are divided into two distinct operating modes: High Pressure (HP) and Low Pressure (LP). It is anticipated that during the 20-year design life of the FPU, 5 years will be spent in HP operation, while the remaining 15 years will be in LP operation. Detailed descriptions of the systems and each topside facility are given in the below sub-sections.

3.2.3.9 HP Inlet Facilities

The FPU HP inlet facilities comprise the following equipment:

- Pig Receiver
- HP Inlet Heaters
- HP Inlet Separator
- Start-up/Depressurisation Heater

Pig Receiver

A pig receiver is installed to receive production pigs launched from the subsea production manifold. Given the cleanliness of the production fluids (i.e., no wax or gel formation expected), pigging is anticipated once every 3–5 years, primarily for gauging and inspection. As such, the pig receiver is normally isolated (by removing a spool piece and blinding the connections) from the main production piping when not in use.

HP Inlet Heaters

Production fluids are heated by two operational HP inlet heaters, with a third heat exchanger kept as a spare. These heaters are of the shell and tube type, with a duty of 6,744 kW, rated for 140 barg. The production fluid enters the tube side, while the heating medium is on the shell side. The fluids are heated to 30°C before entering the HP Inlet Separator.

HP Inlet Separator

A production control valve provides fine control of the pressure for fluids entering the HP Inlet Separator. This valve is of the inching type to prevent sudden pressure surges and includes a minimum mechanical stop to ensure an open path for depressurization.

The HP Inlet Separator is a two-phase horizontal separator designed to operate at a pressure of 105 barg (with a design pressure of 140 barg) and a temperature of 30°C. It is designed for an inlet flow rate of 10.5 million Sm^3/day and a flow rate of 62 m^3/hr of a rich MEG-water mixture (69 m^3/hr including a 10% flow margin). It has a slug-handling volume of 30 m^3, accommodated between the low and high-level alarm settings. Additionally, sand jetting internals and connections have been incorporated to allow online sand jetting if required.

The HP Inlet Separator pressure is controlled by two dump-to-flare valves operating on split-range control, which are sized to handle the full flow of 3 compressor trains (10 million Sm^3/day). One flare valve is sized for 25% of the flow for fine control, while the other is sized for the remaining 75%.

HP mode operation

Approximately 0.5 million Sm^3/day of gas is extracted for fuel gas consumption. This gas is routed through the pressure control valve upstream of the HP Fuel Gas Scrubber. The remaining gas is directed to the HP Compressor 1st stage discharge scrubber, which feeds into the 2nd stage compressor.

LP mode operation

The HP Inlet Separator is not used during LP mode. Instead, the gas from the HP Production manifold is directed to the LP Inlet Separator.

Start-Up/Depressurisation Heater

The start-up/depressurisation heater is a shell and tube exchanger. It is primarily used during start-up (riser de-packing), as the arriving fluid is expected to be below normal temperature. The heater prevents ice or hydrate formation by heating the gas on start-up when risers are packed at a well shut-in pressure of 361 barg (where the Joule-Thomson effect can cause sub-zero temperatures).

The heater is also used for riser depressurisation during prolonged shutdowns. Connections are available from the gas export riser to the heater for this purpose.

The heater has a duty of 5,389 kW and is rated for 361 barg. Production fluids enter the tube side, with the heating medium on the shell side. The fluids are heated to 93°C before being returned to the HP Production manifold.

3.2.3.10 HP Production Manifold

The arrival process fluid condition at the FPU inlet is expected to be 110 bara during HP mode and 40 barg during LP mode. Given that the well shut-in pressures are 362 bara, the inlet piping up to the HP production manifold outlet is fully rated.

The production inlet flowline from the riser is provided with the following:

- Emergency Shut-Down (ESD) Valve, which is a full-bore (FB) and piggable valve
- MEG/Methanol/Nitrogen injection point
- Piggable barred tee
- Corrosion coupon for monitoring riser integrity
- Sand detector
- Manual diverter valves to direct production fluids to the Start-Up/Depressurisation Heater
- High Integrity Pressure Protection System (HIPPS)

The HIPPS, in combination with the fully-rated production manifold, protects downstream lines and equipment from overpressure and potential containment loss. This design allows for a pressure reduction from 361 barg to 140 barg for piping sections downstream of the HIPPS valves. After this, production fluids flow to the HP Inlet Heaters for heating.

3.2.3.11 LP Inlet Facilities

The FPU LP inlet facilities comprise the following equipment:

- LP Inlet Heaters
- LP Test Inlet Heaters
- LP Inlet Separator

- LP Test Inlet Separator

LP Inlet Heaters

The LP Inlet Heaters are of the shell and tube type, with a duty of 4,320 kW (including a 10% margin on heat duty and a 10% margin on overall heat transfer area). They are rated at 45 barg. LP production fluid enters the tube side at 33 barg and -7°C and exits at 32.5 barg and 30°C.

LP Test Inlet Heaters

As the heating duty required during LP operation exceeds the capacity of the LP Inlet Heaters alone, the LP Test Inlet Heater is used in tandem with them to provide the necessary heat load.

The LP Test Inlet Heater is also a shell and tube type, with a duty of 1,670 kW (including a 10% margin on heat duty and a 10% margin on overall heat transfer area), rated at 45 barg. LP production fluid enters the tube side at 33 barg and -7°C and exits at 32.5 barg and 30°C.

LP Inlet Separator

The The LP Inlet Separator is a two-phase horizontal separator designed to operate at 32 barg (with a design pressure of 45 barg) and a temperature of 30°C. It is equipped with internals to ensure the separation of liquids (rich MEG and produced water) from gas. The rich MEG and produced water mixture is routed to the LP Test Separator and then to the MEG reclamation unit. Gas is routed to the safety knock-out drum.

LP Test Inlet Separator

The LP Test Inlet Separator is a two-phase horizontal separator designed to operate at LP flare pressure (with a design pressure of 45 barg) and a temperature of 30°C. The gas outlet is open directly to the LP flare, while the liquid outlet is sent to the Rich MEG tank in the hull.

This vessel serves as a Rich MEG flash vessel, where any dissolved hydrocarbons from both the HP Inlet Separator (during HP operation) and the LP Inlet Separator (during LP operation) are flashed off before entering the MEG reclamation unit.

3.2.3.12 LP Production Manifold

During LP operation, production fluid is routed from the HP Production manifold to the LP Production manifold. A manually operated production control valve is used to finely control the inlet pressure into the Inlet Gas Separator.

3.2.3.13 HP Safety Knock-Out (KO) Drum

This vessel is only operational in LP mode. The HP safety knock-out drum is located upstream of the HP compression trains. Gas from the LP Inlet Separator enters this vessel to separate any liquids carried over from the separation system. The HP safety knock-out drum is equipped with a mist eliminator designed to remove liquid droplets from the gas stream at a rate of up to 0.1 US gallons per MMSCF.

Any accumulated liquid is routed to the condensate flash drum via a level control valve.

Approximately 0.5 million Sm^3/day of gas is extracted for fuel gas consumption. This gas is routed directly to the HP Fuel Gas Scrubber in the fuel gas unit.

3.2.3.14 HP Gas Compression System

The HP Gas Compression Unit consists of 3 × 33% capacity trains with a total compression capacity of 10 million Sm^3/day. The gas is compressed to the pressure at 202 barg at the 2^{nd} stage compression outlet flange, to achieve the gas export pressure at 196 barg. Each compression train comprises of two compression stages and one gas turbine drives the two compression stages with a common shaft.

Equipment items that form the part of each HP Gas Compression train are:

- 1st Stage Suction Scrubber
- HP Compressor
- 1st Stage Discharge Cooler
- 1st Stage Discharge Scrubber
- 2nd Stage Discharge Cooler

The inlet and discharge piping of the three HP compressors are connected by common manifolds. Any hydrocarbon liquids separated in the scrubber vessels are sent to the condensate flash drum, though normally no flow is expected.

In HP mode, the gas to the 1st stage compression originates from the HP Inlet Separator. In LP mode, the gas is routed from the LP Inlet Gas Separator directly to the HP Compressor's 1st Stage Discharge Scrubber.

The suction pressure of the HP compressor's 1st stage is controlled by adjusting the speed of the gas turbines in each train. This matches the flow from the wells with the amount of gas passing through the compressors. A load-sharing control panel is included in the Gas Turbine/Compressor skid. Each stage of the compressor is equipped with an anti-surge controller that protects the machine from compressor surge. The throughput of the compressor is regulated by the capacity recycle valve, mounted parallel to the anti-surge valve.

Gas recycled from the outlet of the HP 1st and 2nd stage coolers, back to the compressor suction, may potentially form hydrates across the anti-surge or capacity control valve, which is undesirable due to the risk of blockage and the accompanying over-pressurisation of downstream piping. To prevent this, a significant portion of the recycle flow is taken directly from the hot gas compressor discharge, upstream of the after-cooler as a hot gas recycle stream. This stream is then mixed with the cold stream taken from downstream of the cooler and fed to the recycle valves. Once the anti-surge control valve or recycle control valve opens, the hot recycle valve opens fully and remains open until the temperature in the recycle valve manifold downstream is sufficiently high. When the temperature reaches a sufficient level, the temperature control loop takes over, adjusting the temperature control valve as needed. This setup ensures that the temperature downstream of the recycle valves remains above the hydrate formation temperature.

In addition to the hot gas bypass, methanol injection is provided upstream and downstream of the recycle valve manifolds (capacity recycle valve and anti-surge control valve). Methanol injection is a pressurized system, with the capability to inject methanol at specific points to inhibit hydrate formation. Each injection line is equipped with an on/off valve that automatically opens when the recycle or anti-surge control valve opens, initiating methanol injection.

The three gas turbines use available fuel gas for combustion. Various drains from the turbine skids are connected to open and closed drain headers based on the type of fluid discharged. The exhaust gas from the turbine is sent to the Waste Heat Recovery Unit (WHRU), where heat from the waste gas is recovered to replenish the temperature lost in the heating medium. The temperature of the heating medium supply is maintained by hydraulically operated dampers in the WHRU.

HP Mode Operation

In HP mode, only the 2nd stage compression is running. The gas from the HP Inlet Separator enters directly into the 1st Stage Discharge Scrubber and then into the HP Compressor, where it is compressed from 100 barg to 202 barg. After compression, the gas is fed to the 2nd Stage Discharge Cooler, where it is cooled from 100°C to 40°C. The cooler uses a cooling water mixture (80% water/20% MEG) with a globe valve in the outlet line locked in position to ensure a constant flow of water through the exchanger. A temperature transmitter is installed downstream of the cooler to initiate a process shutdown in case of high temperature.

LP Mode Operation

In LP mode, both first and second-stage compressors are in operation. Gas from the HP Safety KO Drum enters the HP compressor's 1st Stage Suction Scrubber, where any liquid in the feed gas is separated. Accumulated liquid is sent to the condensate flash drum, which operates on an on/off level control.

The gas from the scrubber enters the 1st stage of the HP compressor, where it is compressed from 30 barg to 100 barg at discharge. The compression system in LP mode is a two-stage centrifugal type, with each stage equipped with an anti-surge control system to protect the individual compressor.

Gas from the 1st stage HP compressor is then fed to the HP compressor's 1st Stage Discharge Cooler, where it is cooled from 156°C to 40°C. The cooler uses a cooling medium, with a globe valve in the outlet line locked in position to ensure a constant flow of water through the exchanger. A temperature transmitter is installed downstream of the cooler to initiate a process shutdown if the gas temperature is too high.

The cooled gas then passes through the HP Compressor's 1st Stage Discharge Scrubber, where any liquid in the gas is separated. Liquid accumulated in this scrubber is sent to the condensate flash drum on on/off level control. Gas from the 1st Stage Discharge Scrubber is then fed to the 2nd Stage HP Compressor for further compression to 202 barg. The gas exits the compressor at 110°C, and is cooled to 40°C in the HP compressor's 2nd Stage Discharge Cooler, using a cooling medium with a globe valve as previously described. Similarly, a temperature transmitter is installed downstream of the cooler to initiate a process shutdown if the gas temperature is too high.

The high-pressure cooled gas leaves the HP Compression system and goes to the Gas Dehydration System for further treatment.

3.2.3.15 Gas Dehydration System

The Gas Dehydration Unit (GDU) is designed to remove water from the gas prior to export, using triethylene glycol (TEG), which is regenerated within the TEG unit.

The GDU equipment are:

- Gas Filter Separator
- Gas Dehydration Column
- Gas Glycol Exchanger
- Glycol coalescer

The TEG Regeneration Unit equipment are:

- Glycol Reflux Coil

- Cold Lean/Rich Exchanger
- Glycol Flash Drum
- Glycol Particle Filter
- Glycol Carbon Filter
- Hot Lean/Rich Exchanger
- Glycol Still Column
- Glycol Reboiler
- Reboiler Heater
- Glycol Stripping Column
- Glycol Surge Drum
- Glycol Recirculation Pump

Gas Dehydration Unit (GDU)

The GDU and TEG regeneration unit, along with the fuel gas conditioning unit, are located in the same module. Gas from the compression system enters the gas filter separator, located immediately upstream of the glycol contactor. This vessel removes any free liquids or particles present in the gas. The filtered gas is then sent to the gas dehydration column for dehydration. Any liquids knocked out or coalesced in this separator are channelled to the condensate flash drum.

Wet gas from the gas filter separator enters the gas dehydration column, operating at 200 barg and 37.5°C. The bottom section of the contactor provides free liquid removal. This bottom section has a proprietary inlet distributor installed, which breaks the momentum of the fluid and allows for satisfactory vapor-liquid disengagement.

Chimney trays are provided above the distributor for even distribution of gas through the structured packing. Due to the hygroscopic nature of TEG, which has a preferential affinity for water, entrained water in the wet gas is absorbed by the lean TEG. Dehydration of the gas takes place across 4900 mm of structured packing, against a counter-current flow of lean TEG. The dehydrated gas leaving the top of the column passes through a 150 mm thick pad-type wire mesh mist eliminator to remove any entrained TEG before leaving the tower.

The lean TEG is distributed evenly across the packing with a high-efficiency liquid distributor. Liquid distribution is achieved through drops arranged on a 100 mm square pitch, sized to extend to within 25 mm of the top of the packed bed, minimizing liquid maldistribution and entrainment caused by the vapor flow. As the lean TEG flows down the surface of the structured packing and into the chimney tray, it absorbs water from the gas.

Wet gas becomes drier as it flows upward through the packing, while the lean TEG becomes richer with water as it flows downward. Towards the top of the tower, the lean TEG is at its leanest (highest TEG concentration), with only trace amounts of water vapor remaining in the gas. Although less water is removed towards the top, the difference in water vapor concentration between the lean TEG and the gas is crucial for removing these last trace amounts of water, ensuring the required outlet gas dew point specification of 2 lb water/MMSCF gas is met.

It is important that the lean TEG entering the top of the GDU be cooled to about 5-8°C above the inlet gas temperature. This is necessary because equilibrium conditions between the lean TEG and water vapor in the gas are affected by temperature. Additionally, it prevents hydrocarbon condensation inside the TEG column. At higher temperatures, more water remains in the gas stream due to vapor pressure under equilibrium conditions. To achieve this cooling, the lean TEG from the glycol recirculation pump is cooled by the gas glycol exchanger, an external shell and tube heat exchanger.

To control the lean TEG temperature entering the contactor, a differential temperature control (between the gas inlet and lean TEG inlet into the contactor) is implemented, controlling the lean TEG through the gas glycol exchanger. Rich TEG is collected from the bottom of the vessel and discharged under a level control valve to the TEG reflux coil, located in the TEG regeneration system.

The contactor is designed to operate at 10% turndown of 0.98 million Sm^3/day of gas. During gas turndown operations, it is not recommended to reduce lean glycol flow, as it is still necessary to maintain the lean TEG wetting of the packing.

Gas leaving the contactor is dehydrated to a maximum water content of 2 lb/MMSCF, with lean TEG at 99.40 wt% and a circulation rate of 5.987 m^3/hr.

Dry gas from the contactor is then slightly warmed by exchanging heat with the lean TEG stream in the gas glycol exchanger. The gas glycol exchanger is a shell and tube heat exchanger. Lean TEG from the glycol recirculation pumps enters the shell side of the exchanger and is cooled to within 5-8°C of the gas temperature by the gas flowing on the tube side. The heat exchanger duty is 126 kW (142.6 kW with a 10% margin on surface area). A temperature differential control across the gas glycol exchanger is provided to maintain the temperature under varying gas flow rates and turndown operations.

After exiting the gas glycol exchanger, the dry gas enters the glycol coalescer, which removes any free TEG droplets entrained in the gas stream, minimizing TEG losses. An over-design margin of 15% of gas flow has been provided. The glycol coalescer is designed to operate at 200 barg and 37.5°C. Gas leaving the coalescer is then metered and exported from the FPU.

TEG Regeneration

Rich TEG exits the contactor tower at the bottom and is channelled to the glycol reflux coil. This glycol reflux coil, located at the top of the glycol still column, is used to rectify the vapor and minimize TEG losses. Rich TEG flowing through the glycol reflux coil is warmed to approximately 43°C by steam and rich TEG vapours, while water vapor present at the top of the column condenses on the shell side. A temperature transmitter is located so that it is visible to the operator when adjusting the reflux condenser bypass valve; if the temperature exceeds the high set point, TEG entrainment with the outlet vapor is likely, and if it falls below the low set point, the reboiler heat duty will increase. The overhead temperature is adjusted manually based on the temperature transmitter reading by allowing the rich TEG to bypass the glycol reflux coil by opening the globe valve. The glycol reflux coil normally operates at about 5 barg but is designed for 220 barg in case of a failure in the gas dehydration column’s level control, causing accidental gas blow-by through the level control valve and blocking the cold lean/rich exchanger.

Rich TEG from the glycol reflux coil is sent to the tube side of the cold lean/rich exchanger, where it is warmed by the counter-current flow of lean TEG to approximately 68°C before entering the glycol flash drum for effective separation and removal of dissolved gas and any liquid hydrocarbon dropout. This is a bare hairpin-type heat exchanger with a duty of 114 kW (126 kW with an additional 10% margin on surface area).

The glycol flash drum removes any gaseous hydrocarbons absorbed in the glycol contactor. It also serves to separate out any liquid hydrocarbons that may have dropped out of the TEG, preventing them from entering the glycol reboiler, which could cause fouling, foaming, and flooding.

The glycol flash drum is a three-phase separator sized for a 20-30 minute residence time while operating at 60% full. In this drum, any dissolved hydrocarbons are separated from the TEG and sent to the LP flare header under a back-pressure control valve. Condensate (if any) is collected in a skim bucket and sent to the condensate header and then to the condensate flash drum (condensate skimming is expected to be a manual operation). A fuel gas blanket is provided to supplement the gas flow if necessary to maintain vessel pressure.

Rich glycol then enters the glycol particle filters, which are used to remove solid impurities over 5 µm in size to avoid plugging, fouling, and foaming. These filters are sized for 100% flow and 99.9% particle removal efficiency, and they are 100% spared to allow for online maintenance. After the physical removal/filtration of particulate matter, the rich glycol flows through the glycol carbon filters. These carbon-based filters remove most foam-promoting compounds or products such as well-treating chemicals, compressor oils, and other organic impurities that may be present in the rich TEG. This filter is sized for a slipstream flow of 20%, while the remaining flow is bypassed, and the bypass flow is controlled manually.

The filtered rich TEG from the glycol carbon filter is then pre-heated to 163°C from 68°C in the tube side of the hairpin-type hot lean/rich exchanger through heat exchange with the outgoing lean TEG from the glycol stripping column. The hot rich TEG from the exchanger flows across the glycol flash drum level control valve into the glycol still column. The glycol flash drum level control valve is located downstream of the hot lean/rich exchanger to maintain backpressure on the exchanger, minimizing vapor generation within the tubes.

The glycol still column is a vertical distillation/fractionation column located on top of the glycol reboiler. This column operates at atmospheric pressure and is designed with one theoretical stage above the feed and one theoretical stage below. The TEG flows downwards across the packing and is partly regenerated in the glycol still column through contact with rising vapours generated by the glycol reboiler. Vapour rising through the glycol still column is partially condensed by the glycol reflux coil. The partly regenerated TEG leaving the bottom of the glycol still column enters the front end of the glycol reboiler to be further regenerated to 99.040 wt% (with fuel gas used as stripping gas).

The glycol reboiler is a horizontal vessel used to boil off water from the TEG using electric reboiler heaters to regenerate lean TEG.

Partially regenerated TEG from the glycol still column enters the glycol reboiler vessel and is heated by reboiler heaters. These heaters are electric type (3 × 50%) and are designed to operate as 2 × 50% with 1 × 50% as an installed spare. The installed spare heater may need to be turned on when high molecular weight hydrocarbon gas is processed to meet lean TEG concentrations and achieve the specified gas dew point. The regenerated TEG flows by gravity across the length of the glycol reboiler and enters the glycol stripping column. The glycol reboiler temperature is automatically controlled through the three electric reboiler heaters in the heater control panel skid.

Regenerated TEG flows from the top of the glycol stripping column by gravity, while the fuel gas (used as stripping gas) flows upwards in a counter-current flow pattern. The use of stripping gas reduces the water content of the regenerated TEG by counter-current contact with hot fuel gas flowing upwards through the glycol stripping column. This also reduces the partial pressure of the vapor in the glycol reboiler, thereby increasing its regeneration capability. The regenerated TEG (lean TEG) exits the column bottoms and flows into the shell side of the hot lean/rich exchanger, where it is cooled to approximately 105°C, then into the shell side of the cold lean/rich exchanger, where it is further cooled to 77°C before entering the glycol surge vessel.

The glycol surge vessel functions as a reservoir for regenerated TEG (lean TEG). Lean TEG from the shell side of the cold lean/rich exchanger is sent to the glycol surge drum, which is designed to hold liquid drained from the glycol reboiler drum during maintenance of the heater bundles. This glycol surge vessel also provides storage capacity for the glycol circulation pumps.

The glycol recirculation pumps are positive displacement pumps operating at a normal discharge pressure of approximately 202 barg with a pump capacity of 6.3 m³/hr. The lean TEG from the pumps is sent to the tube side of the gas-glycol exchanger and then to the gas contactor. A start-up line is provided, allowing lean TEG to be recycled back to the glycol surge vessel during initial start-up/commissioning. This line can also be used to turn down lean TEG flows to the contactor, though it is not advised to do so to avoid absorption issues.

3.2.3.16 Gas Export

The gas export system includes the following instrumentation:

- Ultrasonic Gas Meter (for gas export)
- Ultrasonic Gas Meter (for gas buyback)
- Backpressure Control Valve

The gas export flowline is equipped with the following:

- MeOH/nitrogen injection point
- Piggable, barred tee
- Tie-in point for temporary pig receiver installation
- ESD valve which is a full bore (FB) and a piggable valve

Gas export metering requires high accuracy; thus, ultrasonic meters are used. Since these meters are not accurate for measuring reverse flow (during gas buyback operations), a separate meter run is provided. Additionally, to maintain constant back pressure to the compressors, a pair of pressure control valves are installed.

3.2.3.17 Pig Launcher

A pig launcher is installed to enable intelligent pigging for gauging the gas export pipeline. At this point, the gas export process conditions are 196 barg and 40°C, with gas entering the 16” gas export pipeline to the onshore facility. A spare 16” gas export riser has been provisioned for in terms of a spare riser slot as well as space. Additionally, the piping configuration is such that the pig launcher can launch pigs into either the gas export pipeline or the future export riser at any one time.

The pigging motive fluid is expected to be dry gas from the GDU during turndown conditions. To ensure sufficient motive force for the pig to travel toward the onshore gas receiving facility, this kicker line is taken upstream of the pressure control valve.

3.2.3.18 MEG Recovery/Regeneration

The MEG Recovery and Regeneration Unit is designed to remove salts with minimal MEG losses while also removing water to achieve the required outlet glycol purity.

The process consists of three main sections:

- MEG Pretreatment section to remove free light hydrocarbons and precipitated divalent salts.
- MEG Reclamation and Monovalent Salt Removal, for monovalent salt precipitation and removal.
- MEG Regeneration Module for water removal.

In the Pretreatment section, rich MEG from inlet separation is routed to the Rich MEG Flash Drum, which is designed for 3-phase separation. Dissolved gases and entrained vapor flash out of the liquid at lower operating pressure, and free hydrocarbons (if any) are automatically skimmed off and removed. The rich MEG from the flash drum is routed to hull storage. The rich MEG from the storage tank is then heated before entering the Divalent Salt Removal section. Sodium carbonate and sodium hydroxide are added to adjust the pH and precipitate divalent ions such as Ca^{2+}, Mg^{2+}, Ba^{2+}, Sr^{2+}, and Fe^{2+}. After sufficient time for precipitation in the Divalent Salt Precipitation Vessel, the divalent salts are removed in the Divalent Salt Filtration system. Maximum of 14.1 tons of divalent salts are anticipated to be generated in daily basis.

In the Reclamation Module, rich MEG is fully flash vaporized by mixing with a heated recycle liquid in the Flash Separator. The non-volatile solids are separated from the MEG and removed in the Monovalent Salt Removal Section. The process downstream of the Flash Separator occurs under vacuum to reduce processing temperatures.

In the MEG Regeneration Module, rich MEG is distilled in the MEG Regeneration Column to remove water, producing lean MEG for reinjection back to the subsea manifold.

3.2.3.19 Utility Systems

Cooling Medium

The cooling medium system is designed for a total duty of 97 MW and a flow rate of 3204 m³/h, including a 10% margin on the total calculated duty (the margin does not account for flow to the slipstream filter).

The cooling medium system will consist of the following equipment:

- Cold Medium Expansion Drum – 1×100%
- Seawater-Cold Medium Coolers (20.8 MW each) – 4×25%
- Cold Medium Circulation Pumps (1500 m^3/h at 50 m head) – 3×50%
- Slip stream filter (as special piping item)

The cooling medium system provides topsides cooling in a closed circuit. The primary consumers will be the gas compression coolers, lean MEG cooler, and MEG regeneration condensers. The cooling medium will be a closed loop of 20 wt% MEG and 80 wt% inhibited freshwater (to prevent freezing), with a supply temperature of 31°C and a return temperature of no more than 55°C.

The Cold Medium Expansion Drum is pressurized with nitrogen to 0.5-1 barg. The Seawater-Cold Medium Coolers use seawater from the engine room seawater lift pumps. The maximum seawater supply temperature is 26°C, and the seawater outlet temperature is limited to 35°C.

The Cold Medium Circulation Pumps provide a 50 m differential head to supply the process coolers with cold medium. A slipstream filter is installed downstream of the pumps to continuously filter 5% of the cold medium flow rate, which is routed directly to the return header.

Heating Medium

The heating medium system is designed for a total duty of 62 MW and a flow rate of 1,609 m³/h, including a 10% margin on the total calculated duty (the margin does not account for flow to the slipstream filter).

The heating medium system consists of the following equipment:

- Heating Medium Expansion Drum – 1×100%
- Waste Heat Recovery Units (15.4 MW each) – 3×33%
- Steam Heating Medium Exchangers (20.6 MW each) – 3×50%
- Heating Medium Circulation Pumps (700 m^3/h at 50 m) – 3×50%
- Slip stream filter

The heating medium system provides topsides heating in a closed circuit. The main consumers will be the inlet heater and the MEG package. The heating medium will be inhibited freshwater, with a supply temperature of 185°C and a bulk return temperature of 147-150°C.

The Heating Medium Expansion Drum is pressurized with nitrogen to 11.6-12 barg to maintain the heating medium in a liquid state. Hydrocarbon detectors will be installed to detect the presence of any hydrocarbon pinhole leaks into the heating medium system.

The Heating Medium Circulation Pumps provide a 50 m differential head to drive the heating medium through the Waste Heat Recovery Units (WHRUs), Steam/Heating Medium Exchangers, and the process heaters. A slipstream filter is installed downstream of the pumps to filter 5% of the heating medium flow rate, which is routed directly to the return header.

There are two heat sources:

1) The WHRUs are installed on each of the gas turbine drivers for the compressors. Each WHRU is rated at 15.4 MW, but the actual duty will vary depending on the load on the compressor gas turbines (e.g., compressor operating mode, flow rate, pressure, etc.). The WHRUs are designed to extract the maximum possible heat from the gas turbine exhaust gas to minimize fuel gas consumption.
2) The Steam/Heating Medium Exchangers provide any additional heating required, utilizing steam from the deck boilers. They are also used when WHRUs are not in service (e.g., during start-up). Each exchanger is rated at 20.6 MW.

Chemical Injection

The chemical injection system includes one chemical injection skid for miscellaneous chemicals, as well as dedicated storage tanks and pumps for methanol injection. The system will feature local storage tanks and chemical injection pumps for both subsea and topside production plants.

The chemical injection skid will consist of:

- Spare storage tank – 9.0 m^3 – with associated injection pumps
- Scale inhibitor storage tank – 3.2 m^3 – with associated injection pumps
- Corrosion inhibitor storage tank – 6.4 m^3 – with associated injection pumps

Each of the chemical storage tanks listed above is equipped with 2 × 100% injection pumps. Each pump has an adjustable stroke length ranging from 0% to 150% capacity.

The methanol injection system will consist of:

- Subsea methanol storage tank (Phase 1) – 48 m^3 – with associated injection pumps
- Topsides methanol storage tank (Phase 1) – 24 m^3 – with associated injection pumps

Each of the methanol storage tanks is equipped with 2 × 100% injection pumps. Each pump has an adjustable stroke length ranging from 0% to 120% capacity. The methanol storage tanks will be pressurized with nitrogen at 0.2 barg.

In addition, chemicals required for the MEG Reclamation Unit (sodium carbonate and sodium hydroxide) will be stored in the hull, as the quantities needed for these chemicals are significantly higher.

Flare

The flare tower is a conventional 3-legged tubular space frame structure that supports the flare and blowdown system to suit the existing foundations on hull deck. The overall height of the flare tower primary structure will be 90 m with the Flare Tips' Maintenance Platform at the top. The isometric view of the flare tower and the location of the flare tower on FPU are shown in Figure 3-15.

The flare system will consist of an LP flare system and an HP flare system. The HP flare system will handle relief/blowdown from high-pressure sources, while the LP flare system will manage relief/blowdown from low-pressure sources. The flare system also includes the Closed Drain Drum, which collects process drains from the closed drain header.

The flare system will consist of the following equipment:

- HP Flare Gas Scrubber – 1×100%
- LP Flare Gas Scrubber – 1×100%
- Closed Drain Drum – 1×100%
- HP Flare Liquid Pumps – 2×100%
- LP Flare Liquid Pumps – 2×100%
- Closed Drain Pumps – 2×100%
- HP Flare Tip – 1×100%
- LP Flare Tip – 1×100%
- Blower – 1×100%

The HP Flare system will have two headers: one cold header for fluids expected to be below -46°C and one warm header for fluids expected to be above -46°C. This design prevents warm and wet discharges from mixing with cold and dry gases, which could lead to hydrate formation, ice formation, and low-temperature embrittlement.

The LP Flare system will have a single header for all relevant discharges before routing the gas to the LP Flare Scrubber.

The HP Flare Gas Scrubber, LP Flare Gas Scrubber, and Closed Drain Drum will be equipped with electric heaters to prevent ice formation and high viscosity liquids. The Closed Drain Drum will have an equalization line to the LP Flare Scrubber, floating on the LP flare pressure.

Hydrocarbon gases from the two flare scrubbers will be discharged to their respective flare tips, where they will be combusted. An air blower will be installed to inject assist air into the LP flare tip to promote smokeless burning.

Any liquids collected in the scrubbers or drum will be pumped to the slop tank under on/off, lead/lag control.

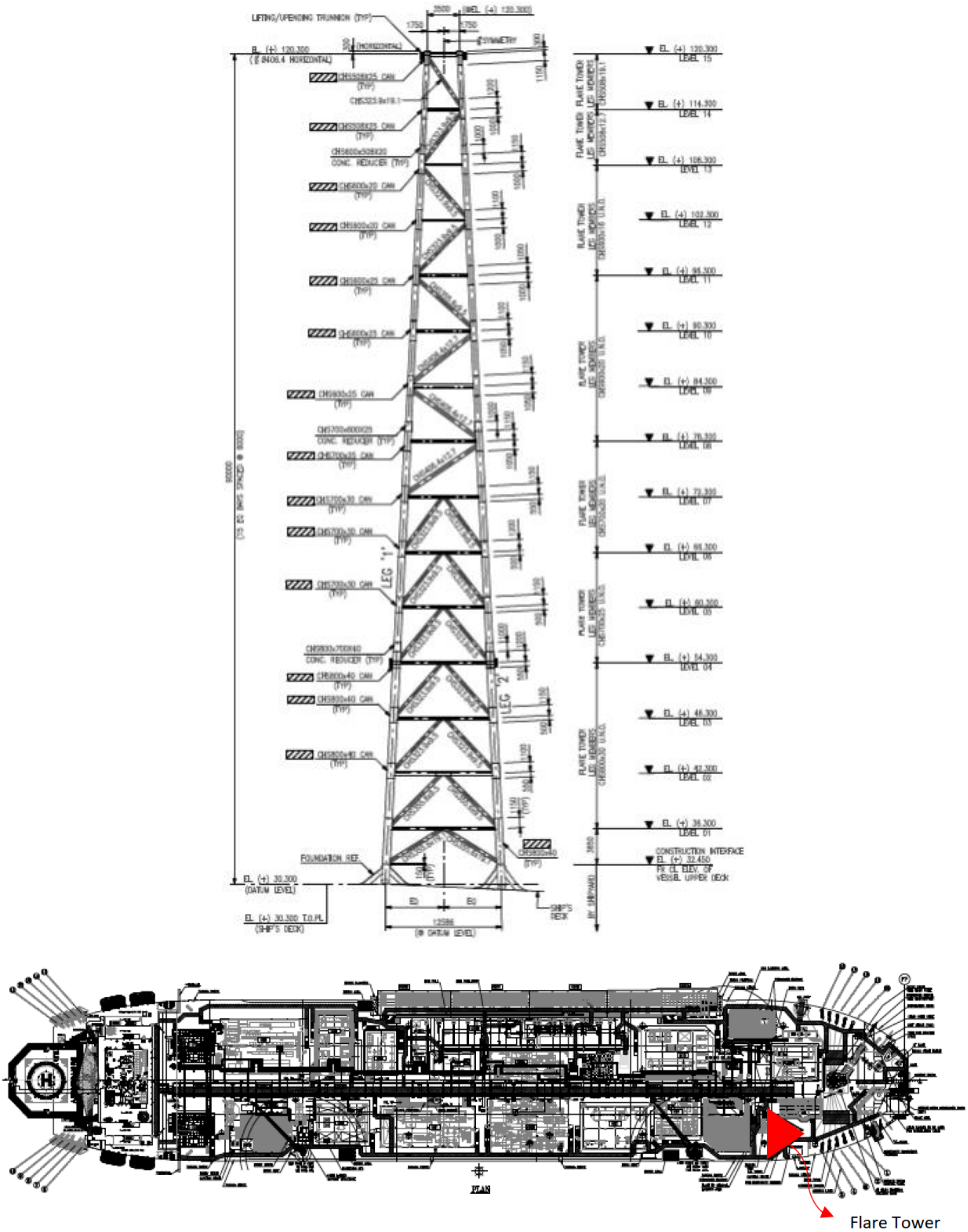

Figure 3-15: Isometric View of the Flare Tower and the Location of Flare on FPU

Fuel Gas System

Fuel gas is sourced from different locations depending on the mode of operation. In HP mode, the fuel gas is taken from the gas outlet of the HP Inlet Separator. In LP mode, the gas is sourced from the gas outlet of the Safety Knockout Drum. There is also a provision for fuel gas buyback in the event of a black start scenario; the source of this fuel gas is downstream of the gas dehydration unit.

HP Fuel Gas System

HP Mode Operation:

In HP mode, fuel gas from the gas outlet of the HP Inlet Separator is fed into the 488 kW (+10% design margin) HP Fuel Gas Pre-heater. This electric heater heats the gas to the required operating temperature so that, after pressure reduction, the temperature is approximately 5°C. This is done to prevent hydrate formation due to the Joule-Thomson Effect when the gas pressure is reduced from 109 barg to 29.7 barg in the pressure control valve.

LP Mode Operation:

In LP mode, HP fuel gas is obtained from the gas outlet of the Safety Knockout Drum, and its pressure is reduced from 32 barg to 29.7 barg by the pressure control valve. Because the Joule-Thomson effect is smaller in this case, this route bypasses the HP Fuel Gas Pre-heater.

Black Start Operation:

In a black start scenario, the fuel gas supply comes from the gas export pipeline at the gas dehydration unit outlet. The inlet pressure is anticipated to be 80 barg. During this operation, the gas will first be routed to the HP Fuel Gas Pre-heater and heated to avoid hydrate formation, then follow the same pathway as in HP mode.

<u>HP Fuel Gas Scrubber</u>

The HP Fuel Gas Scrubber receives HP fuel gas from the two main sources described above. During pressure reduction, flashing occurs in the control valve, and heavier hydrocarbon components may undergo a phase change from gas to liquid, though this is unlikely due to the lean gas composition. The HP Fuel Gas Scrubber includes a mist eliminator at the top to remove HC liquid droplets from the gas. When the two-phase mixture of fuel gas is fed into the HP Fuel Gas Scrubber, separation occurs. The operating pressure of the scrubber is 29.7 barg, with a temperature range of 5-19°C. Fuel gas is collected at the top, while HC liquid is collected at the bottom. The collected fuel gas is then superheated in the HP Fuel Gas Super Heater to meet the fuel superheat requirements.

Any condensate from the scrubber is sent to the condensate heater.

<u>HP Fuel Gas Super Heater</u>

Fuel gas exiting the HP Fuel Gas Scrubber is fed into the HP Fuel Gas Super Heater, an electric heater rated at 316 (394) kW (+10% design margin). In this heater, the fuel gas is superheated from 19.10°C to 39.10°C to meet the minimum superheat temperature requirement for the Gas Turbine Generators.

<u>HP Fuel Gas Filter</u>

The HP Fuel Gas Filters remove any residual HC liquid present in the fuel gas coming from the HP Fuel Gas Super Heater. The filter operates at 28.5 barg and 39°C. Fuel gas supplied to the Gas Turbine Generator must be free of HC liquid (even in trace levels) to avoid turbine blade corrosion. Similarly, the HP fuel gas to the boilers must also be free of HC liquids for safety reasons. The fuel gas exiting the filters is at a pressure of 28.5 barg and is distributed to HP fuel gas consumers, including Gas Turbines (3×33%) for HP compressors, Boilers (2×100%), and LP fuel gas.

LP Fuel Gas System

LP Fuel Gas Scrubber

Fuel gas from the HP Fuel Gas Filter is fed into the LP Fuel Gas Scrubber via a pressure control valve used as a secondary source. The LP Fuel Gas Scrubber operates at 5 barg and 23°C. The outlet gas from the LP Fuel Gas Scrubber is sent to the LP Fuel Gas Super Heater. The pressure control valve is regulated by the pressure transmitter in the LP Fuel Gas Scrubber. HC liquid from the bottom of the scrubber is sent to the condensate header through a level control valve.

LP Fuel Gas Superheater

Fuel gas from the LP Fuel Gas Scrubber is sent to the LP Fuel Gas Super Heater. The LP Fuel Gas Super Heater, rated at 30 (37) kW (+10% design margin), superheats the fuel gas from 34.3°C to 54.3°C. This superheating maintains the supply temperature of the fuel gas for the Water Injection Deaerator, Blanketing Gas for various users, and Flare Purge/Pilot Gas. The superheated fuel gas from the LP Fuel Gas Super Heater is distributed to LP fuel gas consumers, such as HP/LP Flare Purges and the TEG Regeneration Unit.

Open Drain

The open drain system ensures the safe disposal of any leaks from the process area, as well as rainwater and fire-fighting water, to maintain area segregation between process modules and the main cargo deck. The open drain system is divided into hazardous and non-hazardous systems based on module area classification.

Piping from the drain boxes on each module will be manifolded and routed to one of the slop tanks. During normal operation, hazardous drains will be routed to the dirty slop tank.

Closed Drain

The closed drain system is a hard-piped system used for maintenance purposes to drain volumes of hydrocarbons from the topside. Draining of process equipment and piping is a manual operation, and no continuous streams will be routed to the closed drain.

Each closed drain connection is designed to allow positive isolation between process equipment/piping and the closed drain system. Drained liquids are routed via the closed drain header to the Closed Drain Drum, where vapours are disposed of through the LP flare system and liquids can be further pumped to the slop tanks.

3.2.4 Export Pipeline

For the transport of the processed natural gas achieving BOTAŞ sales specifications in the FPU, from offshore to onshore, a new approximately 170 km long, 16-inch steel dry gas export offshore pipeline will be constructed and connected to the existing tie-in point with the BOTAŞ onshore natural gas grid for further distribution.

Construction Phase

Dredging:

For laying of the pipeline in the shallow water Section near shore, a 3 m deep trench will be excavated in the planned pipeline corridor for an overall length of 1,660 m from the shore till approximately 19 m depth.

Approximately 82,200 m^3 of material will be dredged. The Dredging Environmental Management Plan has been prepared and approved by the MoEUCC.

The dredging activity aims to ensure the stability of the pipe coming from offshore by burying it into the seabed sediment from a certain depth, to protect the pipeline from ship anchors, abrasion, and fishing activities along its route. The main focus of the dredging activity is to excavate the route on the seabed where the pipes will be placed, remove the sediment, place the pipe, and then replace the removed sediment back in the same area. The excavated sediment will be used to close the trench.

The trenching activity will be carried out using a backhoe excavator on a barge. A 500-meter safety zone will be established for the vessels that will be working in ditching activities.

The dredged material will be stored temporarily near the port area, which was formerly used for temporary storage of dredged material during Phase 1 construction. The total area where the dredged material will be deposited is 260,000 m², with a minimum water depth of 5 meters and a maximum water depth of 11 meters.

The excavation of the coastal trenches, is expected to be completed in approximately 75 days. After the trench is excavated, it is anticipated that the pipes will be laid within 14 days, and then it will take approximately 167 days to cover the pipe with the dredged material. The total schedule for the dredging activities is approximately 303 days (including weather delays). It is planned to commence dredging activities immediately after obtaining all necessary permits from relevant institutions and organizations.

Dredging and temporary storage areas are presented in the below figure.

Figure 3-16: Dredging and Temporary Storage Areas

Laying in shallow water Section (Shore Crossing Sections) from shoreline to 19 m depth

Once the pipelines which will be previously coated in concrete have been laid, the trench will be backfilled with the excavated sediments, covering the pipeline by a minimum of 2 m.

The cofferdam will be used to reduce the risk of sediment flow from Filyos River into the trench. Figure 3-17 provides a typical cofferdam example. Causeways will be built by raising protective barriers (tubular piles) against the waves on both sides of the ditch made of stones and rocks imported to the site from outside to protect the ditch that has been dug on near shore of coastal crossing by using an open excavation technique (with or without cofferdam, in either case) from sea movements.

The cofferdam has been built on land from KP0 to KP0+332 with a water depth of 3 m. Two rows of cofferdams will form the side walls of the ditch. Soil type, groundwater and environmental conditions will determine the design of these temporary supports. In addition, outriggers can be placed along the trench to provide support against lateral pressures. For lateral strength, an additional cofferdam row can be created and the space between the cofferdam rows filled with excavation material/soil. The internal excavation of the cofferdam, where the pipeline will be laid along this line, will be completed using land equipment. Excavation will be carried out using an excavator from both sides of the cofferdam on the land side, and over the temporary passage/work road to the southwest of the cofferdam on the seacoast.

Figure 3-17: A Typical Cofferdam (Source: Phase 1 EIA Report)

The pipe joints are welded on a pipelay barge moored offshore and an onshore winch is used to progressively bottom-pull a joint length pipe string towards shore from the barge via a steel wire pull wire, as additional joints are welded to the pipe string on the barge. The first joint is capped with a pulling head and pull line running to shore is attached to a winch. When the first weld behind the pipeline pull-head reaches the onshore tie-in location, the barge begins to move offshore in the conventional pipelay mode, as welding on the barge continues. Each completed joint weld will be fully inspected, both visually and by Automatic Ultrasonic Testing.

Offshore backfilling activities shall be commenced after the 16" is laid and their positions are confirmed. Backfilling shall be executed along starting from KP 0+000 up to KP 1+500. Between KP 1+500 – KP 1+670, there will be no backfilling activity. Pipelines shall be buried along their entire route lengths in line with Trench Design. In order not to disturb the axis of the pipes, backfilling works will be executed in two stages similar to dredging works. For the Backfilling with Marine Spread, Backhoe Dredger will be located on the Temporary Disposal Area the dredged material is stocked in the sea and loaded into split hopper barges. Removal of Cofferdam will start partially when backfilling inside of Cofferdam is successfully backfilled inspections. If a section of Cofferdam is meeting the backfilling requirements Tubular/Sheet piles can be removed while the remaining section of Cofferdam is still being backfilled.

After the dredged material is loaded, the bulk vessels will pass through the trench as shown in Figure 3-18 and Figure 3-19.

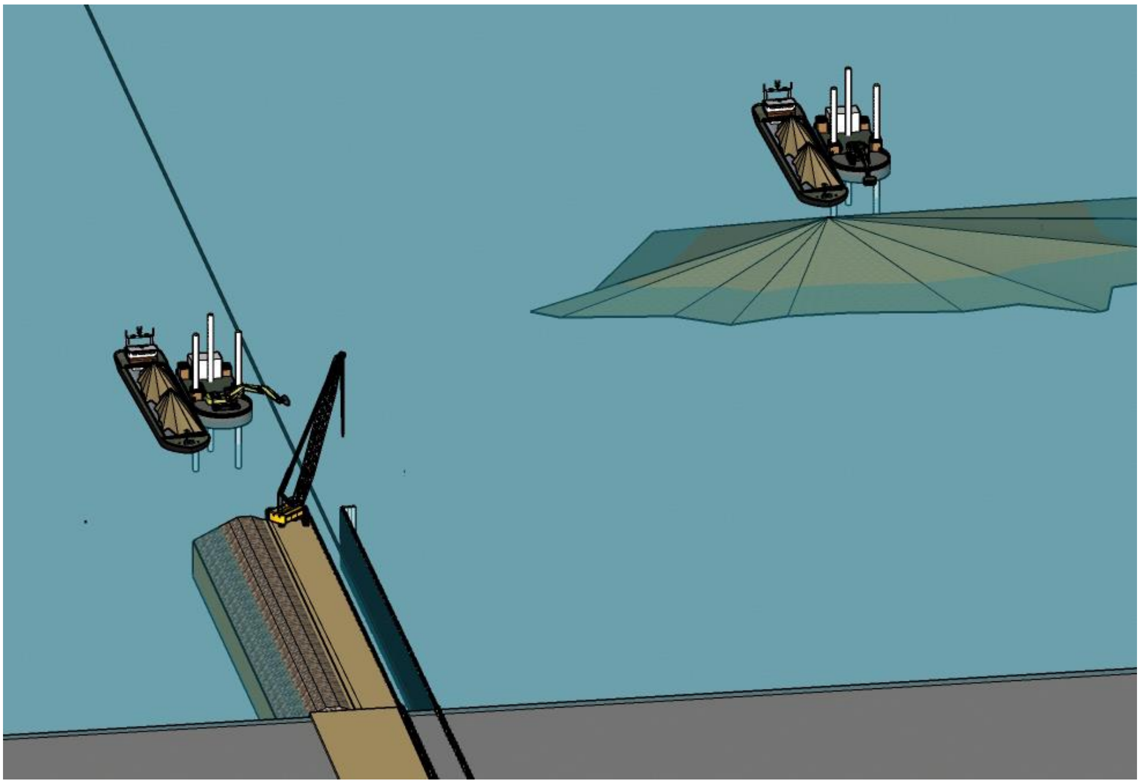

Figure 3-18: Backfill Process – Stage 1

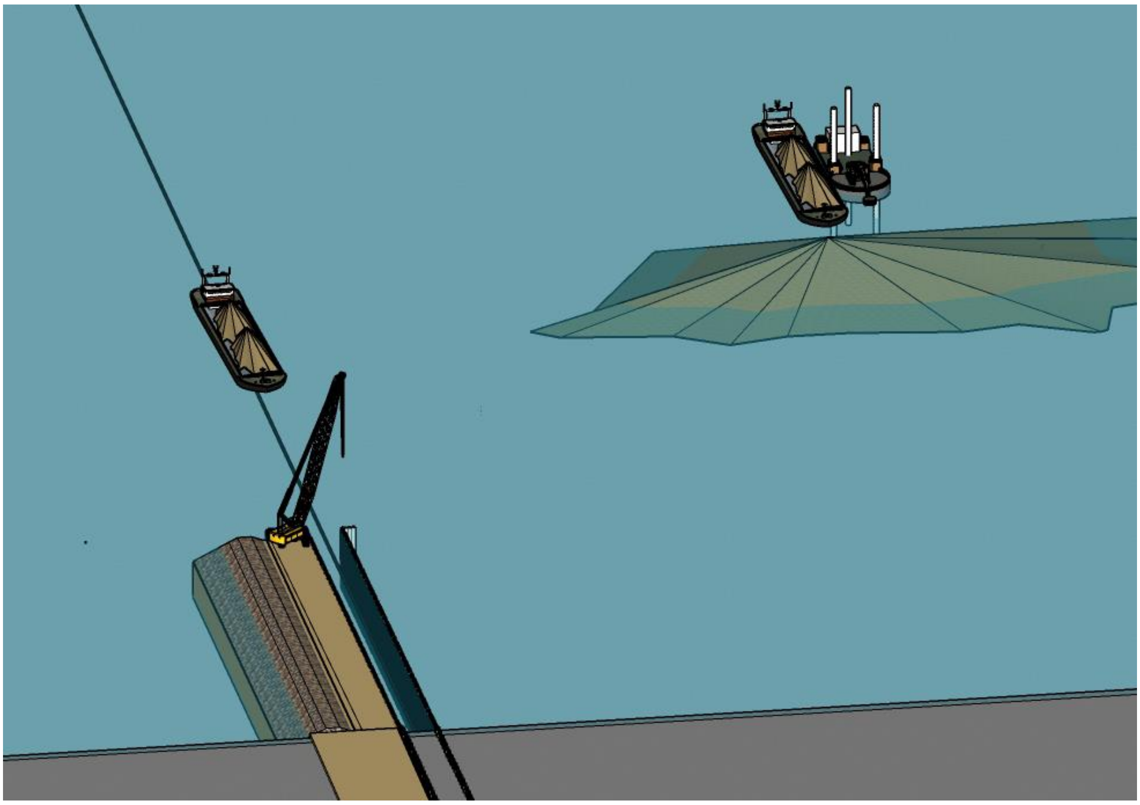

Figure 3-19: Backfill Process – Stage 2

If the excavated sediment stored is insufficient, stability studies will be carried out by importing stones from appropriate quarries. Furthermore, upon assessing the risks of interaction with third parties, the material supplied by the licensed quarries may be utilised to close the ditch or the pipeline Sections that remain outside the ditches. To this end, the "Technical Principles of Planning and Design of Coastal Structures" published by the General Directorate of Infrastructure Investments will be followed in selecting the stones to be utilised as the filler.

The work between KP 0 – KP 0+ 332 involves the use of an excavator for constructing cofferdam and storing excavated material by using it as a work road for itself. The work between KP 0+332 and KP 1+500 involves the use of 17 boats (Survey Boat, Backhoe Dredger, Split Hopper Barge, Trailing Suction Hopper Dredger, Tugboat, Pipe-Lay Barge and Service Boats) for dredging, towing, laying the pipe and surveying. The image and the features of the backhoe dredger vessel are provided in Figure 3-20: . A number of guide rollers will be deployed along the land route leading to the Onshore Processing Facility. These will be utilised to deploy the towing crane.

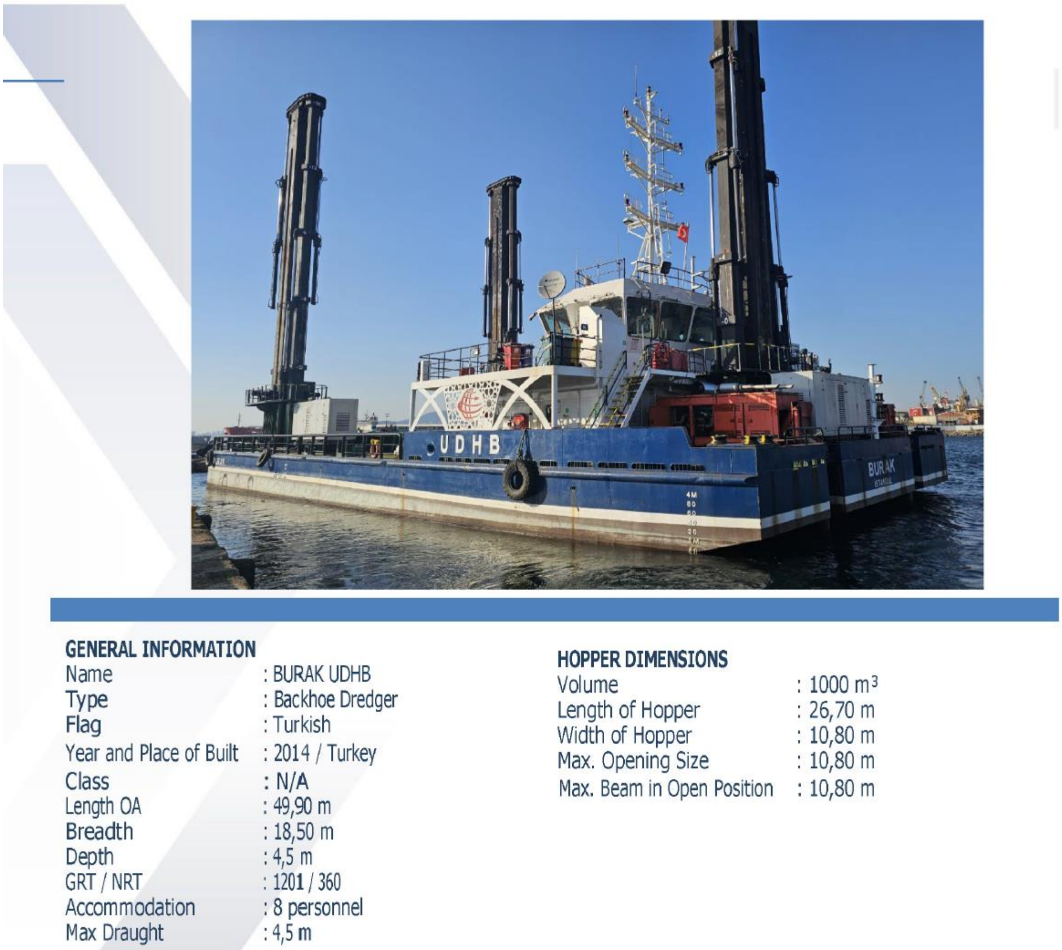

Figure 3-20: Image of Vessel to Be Used at Near Shore Dredging

The materials are anticipated to be transported from the Filyos Port to the construction site of the coastal Crossing Section by barges or by trucks. The quarry to use (if necessary) is close to the site. Security zones of 500 m of either side of the offshore export pipeline and vessels would be setup and NAVTEX announcements will be made. Also, 10 m buffer zone onshore around constructions will be set to prevent unauthorized access.

In the event that the excavated excess sediment that may be generated due to any reason during the construction/installation of pipelines will be dumped into an existing nearby dumping site or another location on the seabed designated by Republic of Türkiye Ministry of Environment, Urbanisation and Climate Change, the requirements of the "Regulation on the Environmental Management of the Dredged Material" will be met upon request by the Ministry.

Laying in offshore Section from 33.58 m depth onward (KP 3+534 – SPS)

The pipeline will be transported by offshore piping barge from where it was temporarily positioned by the shallow water piping barge. Priority temporary piping heads will be removed on the barge. As the pipe welding and coating is completed, the piping will be resumed. The offshore piping barge will engage the dynamic positioning system to fix itself. It will undertake piping activities in parallel with welding and coating works.

The location where the pipeline laid on the seabed will be controlled by ROV launched into the sea through auxiliary ships. This will ensure that the laid pipe remains inside the designated construction corridor. Several piping parameters will be checked during the piping activities. After the completion of the piping activities, a pipeline termination unit will be inserted on the pipe end, extending to the subsea production system. This will connect the pipeline to the production distribution chamber once the construction operations of the sea Section are completed.

The piping barge will intervene after the piping activities to avoid any damage to the pipelines laid on the seabed caused by third-party activity (anchoring, fishing activities, etc.). Two alternative intervention methods are planned: (1) the soil beneath the pipeline shall be mechanically excavated to allow them to be embedded into the seabed, (2) the pipeline shall be covered with gravel to provide protection against external factors.

Where there are gaps due to roughness on the seabed beneath the pipes laid on the seabed, there may be interventions on the seabed after the piping activities to ensure the safe operation of pipeline in long-term. Two alternative methods can be employed to that end: (1) the voids beneath the pipeline can be filled with gravel or mechanical supports (2) the seabed elevation differences shall be rectified to allow the pipeline to subside on the seabed.

Following the completion of the ongoing marine surveys and the development of the design, the requirements and techniques of seabed intervention will be finalized.

The work involves the use of deep water pipelay barge, pipe supply vessel, cargo barges, crew boats.

Pipeline Protection

The pipeline will be protected against corrosion with at least 3 mm thick 3LPP (3 times polypropylene) to be coated outside the pipes. The 3LPP coating is composed of 3 different layers, is resistant to high operating temperatures and provides mechanical protection in addition to corrosion protection. The pipelines will additionally be protected by the sacrificial anode, which will be placed on the pipes as often as the design requires. The design and engineering calculations of the sacrificial anodes will follow the DNV RP 103 standard that examines sea pipelines. The corrosion inhibitor that will be delivered from the FPU top side equipment through the umbilical, as well as the corrosion clearance of 3 mm in the pipeline wall thickness, will ensure corrosion protection in the pipelines.

Pre-commissioning Activities – Export Pipeline

The drawing explaining the gas export pipeline from its starting point, Double Isolation Valve (DIV) onshore to its ending point, Pipeline End Transmission (PLET) offshore is presented below.

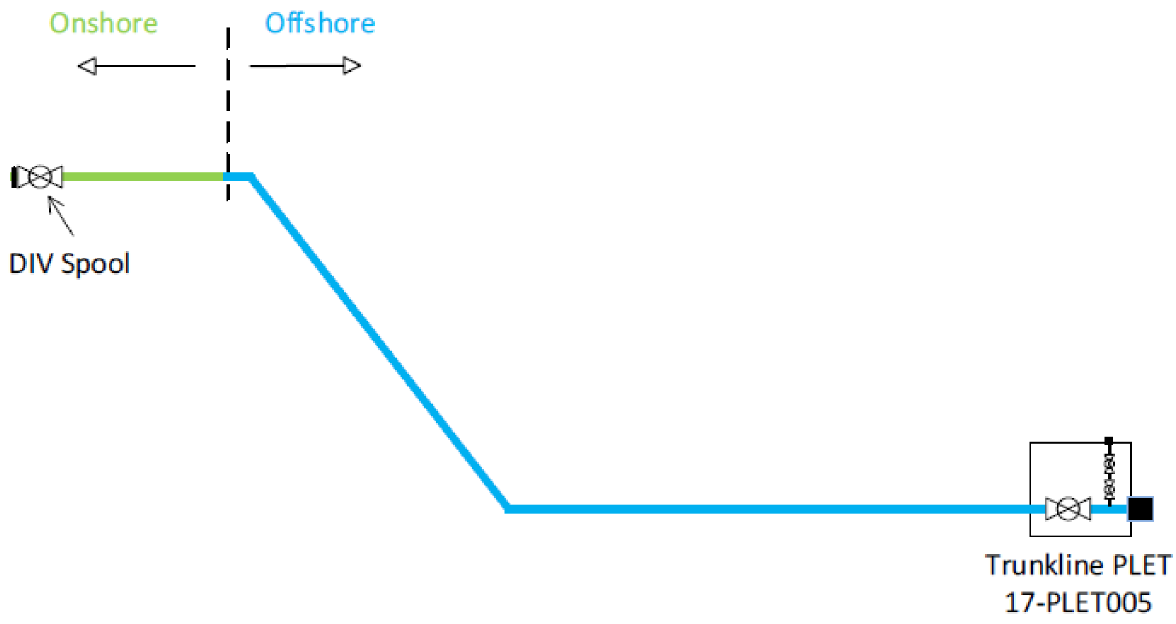

Figure 3-21: Gas Export Pipeline Start and End Points Illustration

Below figure presents the sequence of activities required to perform Pre-commissioning on the Gas Export Trunkline system. Blocks with grey background represent installation activities that have an interface with the Pre-commissioning sequence while blocks with white background represent activities under Pre-commissioning scope.

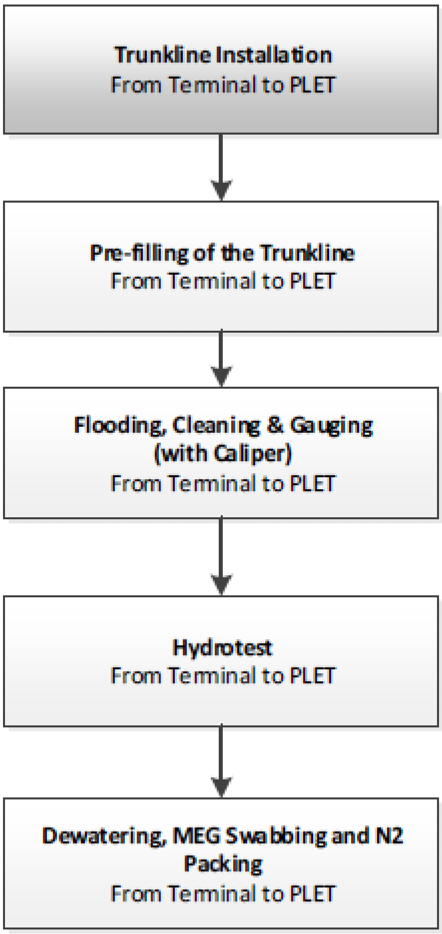

Figure 3-22: Sequence Pre-commissioning Activities on the Gas Export Trunkline System

Following the completion of the construction stage, a number of procedures will be followed to verify that the lines operate smoothly in the expected circumstances. These procedures will confirm that the pipeline were installed as planned, that gas was transmitted at the planned operating pressure, and that all other design criteria were met smoothly. Prior to commissioning, the structural integrity of the subsea system is determined by FCG-H activities which involves following activities:

Pre-filling

Before to proceed with pigging operation, a pre-filling activity is performed in order to allow proper control of pig train velocity during the run. Pre-filling is required due to the seabed profile which is characterized by a severe slope to reach the water depth. Pre-filling activity will be performed from a temporary Pig Launcher Receiver (PLR) connected on the onshore termination by use of filtered seawater (not treated in order to reduce subsea chemical discharge). Due to the use of filtered and untreated seawater, a maximum period of 1-off month is allowed between completion of pre-filling and begin of following FCG operation.

Flooding, Cleaning, Gauging (FCG)

When pre-filling operation is completed, flooding, cleaning and gauging operation will be performed from the temporary PLR connected on the onshore termination (launcher side) to a temporary PLR connected on the

PLET (receiver side). Pig train will be propelled by filtered and chemical treated seawater suitable to guarantee the preservation of the trunkline.

Hydrotest

Following the execution of cleaning and gauging operation, the gas export trunkline will be left flooded with treated seawater and the hydrostatic pressure test will be performed from onshore temporary head/flange to subsea PLET in order to verify the integrity of the installed trunkline.

Dewatering, MEG Swabbing and N2 Packing

After the completion and acceptance of the hydrostatic test, dewatering in conjunction with MEG swabbing activity will be performed with nitrogen (95% of purity) from an onshore temporary head to a subsea temporary PLR connected on the PLET. MEG swabbing activity will be performed with aim to achieve a required equivalent dew point on the Trunkline. Chemically treated hydrotest water and MEG batches used for swabbing will be discharged subsea without any recovery with only exception of subsea MEG samples which will be collected from MEG batches. Considering that dewatering operation is performed directly with use of nitrogen, a dedicated nitrogen purging operation is not required.

After the completion of dewatering, the gas export trunkline internal volume will be isolated subsea by closing the subsea inline valve on the PLET. Then the subsea temporary PLRs will be removed, and a subsea cap will be installed on the PLET hub.

Following completion of subsea isolation, the gas export trunkline will be packed from the onshore termination (inside Terminal) in order to achieve the required final nitrogen packing pressure. Finally, when the required pressure is achieved, the gas export trunkline internal volume will be isolated onshore by closing the isolation valves.

For trunklines scope, seawater will be sourced at Filyos quayside and transferred to the onshore Terminal by the water winning line installed during Phase 1. For infield pipeline, seawater will be sourced infield close to seabed surface by use of subsea unit.

Discharges related with FCG-H activities are presented in Section 3.9.2.4.

Pre-commissioning Activities – Infield Pipeline

The Production Infield pipeline is the line from the PLET to Riser Flowline RTF) connected to the FPU. The infield flowline will be installed in two sections: first the pipe will be installed from the PLET next to DC4 manifold to the transition point between the riser and flowline near the FPU location. Later, a separate vessel will return to install the riser section that eventually is connected to the FPU. The precise sequence of operations and pre-commissioning will depend on the completion date of the FPU and its arrival on the field. The following flowchart shows the sequence of activities required to perform Pre-commissioning on the Production Infield Pipeline. Blocks with grey background represent installation activities that have an interface with the Pre-commissioning sequence while blocks with white background represent activities under Pre-commissioning scope.

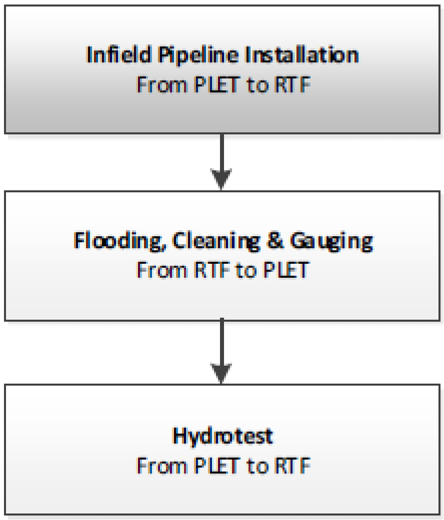

Figure 3-23: Production Infield Pipeline –Pre-commissioning Flowchart

After the installation of the subsea infield pipeline from PLET to a Laydown head at RTF, the recommissioning activities can commence. Laydown Head will be pre-loaded with FCG pig before installation.

The initial condition assumed for infield pipeline is installed empty from PLET to Laydown Head, all valves closed and both ends isolated with temporary caps (at PLET/Laydown Head terminations).

<u>Flooding, Cleaning and Gauging</u>

Flooding, cleaning and gauging operation will be performed from the Laydown Head at one side to a temporary PLR connected on the PLET at the other side by use of a subsea flooding unit. FCG pig will be propelled by use of filtered and chemical treated seawater suitable to guarantee the preservation of the infield pipeline.

<u>Hydrotest</u>

Following the completion of cleaning and gauging operation, temporary PLR at PLET will be recovered, pressure caps will be installed and a hydrostatic pressure test will be performed from PLET to Laydown Head by use of a subsea hydrotest unit in order to verify the integrity of the installed pipeline.

After the acceptance of the strength test, the infield pipeline will be depressurized down to subsea ambient pressure and the internal volume will be isolated by closing the subsea valves and subsea caps on the PLET and on the Laydown Head.

Final condition of the infield production pipeline is as follows:

- Infield production pipeline filled with filtered and treated seawater at subsea ambient pressure;
- Valves in closed position and blind stab installed on the Laydown Head;
- Cap installed on subsea PLET with inline valve in closed position and partially treated seawater between the inline valve and the subsea connector (due to final tie-in activities).

Works at the End of the Construction

After all installation and pre-commissioning activities have been completed, surveys will be undertaken to assess the condition of the seabed components at the end of the installation. These surveys will provide a background value for future work. Sea surveys will be conducted with a magnetometer to pinpoint the location of the pipeline for the embedded Sections. Unembedded Sections such as the seabed pipelines, and connectors will be visually inspected, and their final position and slope data will be documented. All data gathered will be reflected in the reports at the end of construction.

Operation Phase

The onshore inlet line will be connected dedicated subsea offshore line, which is coming from FPU. Thus, the subsea coming gas will arrive onshore de-humidified according to BOTAŞ acceptance criteria. There are existing high pressure and low-pressure flare systems in the OPF. This is also known as the cold flare ground system. The flare systems provide a safe and reliable means of collection and disposal of any hydrocarbon released during upset or emergency conditions, operational venting as well as depressurization and venting of a system during maintenance operations. The gas arriving onshore will be connected to the existing HP/LP flare system. The flow diagram of the gas onshore, also showing the High Integrity Pressure Protection System (HIPPS), is presented below:

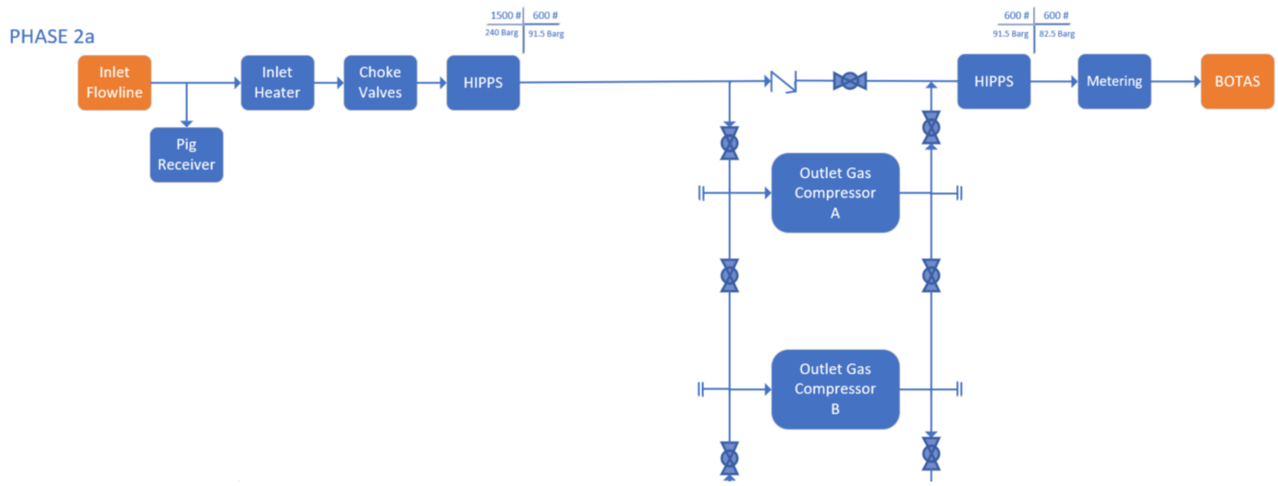

Figure 3-24: Flow Diagram of the Gas – Onshore

The maintenance operations to be conducted during the operating phase of the Project aim to investigate all possible impacts on the pipeline, ensure the safety of personnel, goods and the environment, determine the situations that may obstruct safe and regular natural gas flow, minimize repairs, monitor all incidents based on the cause-and-effect relationship principle for the operations to be conducted during the operating phase.

Since the pipelines are strategically important for the Project, conducting the maintenance-repair operations during the operation phase regularly is essential. The planimetry of the pipelines, filling or emptying of the pipeline bottom due to natural causes and/or pipe and marine bottom profile due to the pipe motions as a result of the marine bottom motions, free moving distances of the pipelines, any kind of natural or superficial event that may affect the pipeline, sea bottom motions in seismic or landslide zones, local or larger damages occurred on the external surface, the status of the previous stabilization applications will be checked continuously. The inspections to be performed including the inspection of outer and inner pipeline surfaces are explained in the following Sections.

Outer Inspections

The scope of the pipeline outer inspections will be determined depending on the line risk analysis, impair and the way of impair of the mechanisms, the results of the previous inspections, measurement limits and accuracy of the control system, and changes in the pipeline operating parameters. The Coastal Transition Section, steep slopes, critical zones like places where tidal movements are observed will be inspected more frequently. ROV and sonar scanning methods will be used during the inspections. Table 3-1 shows the inspections, estimated frequencies and durations. The frequencies of inspections may vary depending on the design requirements and durations may vary depending on the climate conditions.

Table 3-1: Outer Inspection Operations

Name of Operation	Inspection Frequency	Inspection Duration
Inspection of Critical Sections	Annually	2 weeks
Inspection of the Cathodic Protection	Annually	2 weeks
Inspection of the Multi-Beam Echosounder	Annually	2 weeks (to be performed during the inspection of the critical Sections)
Inspection of the Pipeline Location and Levelling	Once every five years	2 weeks
Inspection of the Valves	Annually	3 days

Inner Inspections

The pipeline inner inspections will be performed by using PIG. The status of the inner Section of the pipes will be checked via the sensors over PIG. The initial inspection will be carried out during the pre-operation phase. The operations will be determined according to the design requirements and are planned to be carried out once every five years. Within the scope of the inspections, the pipeline thickness will be measured, and the pipeline will be located.

If planned, the necessary permissions will be obtained for the major repair operations to be performed in the offshore Section. Other inspections to be carried out are shown in the table below.

Table 3-2: Other Inspection Operations

Name of Operation	Foreseen Inspection Frequency	Inspection Duration
Replacement of the Hydraulic Connection Cables and Electrical Connection Cables	Once every twenty years	1 weeks
Chemical Injection	Once every twenty years	1 weeks
Replacement of Anode Plates	Once every twenty years	2 weeks

3.2.5 Existing Components

3.2.5.1 Sakarya Gas Field – Block C 26

Sakarya Gas Field is located in the exclusive economic zone of Türkiye, off the Western Black Sea Region.

Block C 26 is located 155 km from the coast at a depth of about 2,200 m. Gas explorations and wells installation in this area have both been undergoing since October 2020 and are forecasted to continue well beyond 2025.

3.2.5.2 Coastal Logistics Centre (CLC)

Ministry of Transport and Infrastructure allocated the CLC, which is located within the boundaries of the Port of Filyos, to TP-OTC to be used for the coordination of supply and logistics on sea drilling operations in the Black Sea Region, as well as the berthing of drilling support vessels and the loading of drilling equipment on these vessels. CLC operates for the storage of water-based and oil-based drilling chemicals, the supply and storage of the requirements for drilling operations and workers on board, as well as the separation of drilling fluid and sludge that is generated during the drilling activities undertaken by TPAO in Sakarya Natural Gas Basin of the Western Black Sea.

In the scope of the Project, the Coastal Logistics Center will be used for the temporary storage of pipes and equipment; as a workshop/maintenance area during the construction phase: and for marine vessel berthing.

3.2.5.3 Filyos Port

Filyos Port, owned by the Ministry of Transport and Infrastructure, has been allocated to TP-OTC and in the scope of the Project, Filyos Port will continue to be used for marine vessel berthing.

3.2.5.4 SGFD Phase 1

The Phase 1 components described in Section 3.1 of this Report will continue to be operational. Two of the offshore wells, drilled within the scope of the Phase 2 development, will be processed at the OPF. The OPF constructed in the Filyos Industrial Zone, processes the raw natural gas extracted from the Sakarya Gas Field. The OPF includes various units for gas separation, particle filtration, dehydration, and compression to ensure the gas meets the specifications for delivery to the BOTAŞ network. The facility also features safety systems, control rooms, and other support infrastructure to manage and monitor gas processing operations effectively. The ESIA for Phase 1 developments including the OPF prepared in accordance with the IFC Performance Standards, and the Equator Principles was disclosed in December 2022. Outcomes of the ESIA were integrated in TP-OTCs Management System. As such the TP-OTC has fully developed policy, plans and procedures, including mitigation and monitoring measures from the ESIA, for the Phase 1 operations.

The environmental permitting process for Phase 1, including noise, air emissions, and wastewater discharge, is ongoing. In this context, a Temporary Operation Permit which is a prerequisite for the environmental permit is obtained for Phase 1.

<u>OPF Operations:</u>

OPF is designed to process raw natural gas extracted from the Sakarya Gas Field, preparing it for delivery to the BOTAŞ network. The facility comprises several specialized units to ensure efficient gas processing and compliance with safety and quality standards. The operations in OPF is closed to FPU operations. Key components and processes are summarised below:

Gas Acceptance and Separation: The facility first receives the gas-water-MEG (monoethylene glycol) mixture from subsea pipelines. This mixture undergoes initial pressure adjustments and enters the slug catcher, where gas is separated from liquids and particles.

Gas Decomposition and Heating: After the slug catcher, the gas is routed through heaters to adjust its temperature, making it suitable for further processing. Inlet separators then remove remaining liquids, including water and MEG, preparing the gas for dehydration.

Gas Dehydration: The gas dehydration system uses Tri-ethylene Glycol (TEG) to remove water content, ensuring the gas meets sales specifications.

Compression and Export: The dehydrated gas is compressed to meet the pressure requirements for the BOTAŞ network and is monitored for quality and flow rate before being exported through a dedicated pipeline.

Liquid Processing: The facility also includes systems to process and reclaim MEG and other liquids. This involves separating salts and other impurities to produce lean MEG, which is then reused in the system.

Produced Water Treatment: Any water separated during processing is treated to remove pollutants before being safely discharged or reused.

Supporting Infrastructure: The OPF is equipped with various support systems, including chemical injection, fuel gas, flare and vent systems, compressed air stations, water generation packages, and firefighting systems. These systems ensure the facility operates safely and efficiently under all conditions.

The OPF's design allows for management and monitoring of gas processing, ensuring the output meets the required specifications for safe and reliable integration into the national grid.

3.2.5.5 BOTAŞ FMS and Phase-1 Pipeline

In Phase 1, the gas extracted from the Sakarya Gas Field and processed in OPF is measured at a Fiscal Metering Station (FMS) and offloaded to the national grid via a ~36 km onshore pipeline (i.e. BOTAŞ Western Black Sea Natural Gas Pipeline Phase 1- "BOTAŞ Phase 1 Pipeline"). Both the FMS and the natural gas pipeline were designed, constructed, and are operated by BOTAŞ since 2022.

The BOTAŞ Phase-1 pipeline was exempt from the EIA Regulation. As part of the SGFD Phase 1 ESIA studies an Environmental and Social (E&S) Assessment Report was prepared by WSP Türkiye in 2022.

In the FMS, natural gas coming from OPF via a 48-inch pipeline flows through 6x20 inch measurement runs after passing through 4 cyclone filters. Each measurement run has an ultrasonic flowmeter and an orifice to measure the natural gas amount and composition. Once measured, the natural gas flows through the Pipeline Inspection Gauge (PIG) station and from there to the national grid.

In Phase 2, natural gas arriving at the BOTAŞ tie-in point within the OPF Fence will be delivered to the FMS. The connection at the BOTAŞ tie-in point is the battery limit of the Project.

3.2.6 Associated Facilities

3.2.6.1 BOTAŞ Phase-2 Pipeline

The processed dry gas as part of the Project will be transported to the tie-in point within the BOTAŞ station. After the endpoint of the BOTAŞ Western Black Sea Phase-1 pipeline ("BOTAŞ Phase-1 Pipeline"), a new approximately 175 km long and 48-inch pipeline (Western Black Sea Phase-2 pipeline) will be designed, constructed, and operated by BOTAŞ. The Western Black Sea Phase-2 Pipeline will be considered as an Associated Facility (AF) to the main Project, in line with the OECD and IFC Performance Standards definition.

The BOTAŞ Phase-2 Pipeline will start from the endpoint of the Western Black Sea Phase 1 pipeline in Elvanpazarcık Town of the Central District of Zonguldak Province. It will pass approximately 10-20 km southeast of Ereğli and Alaplı Districts and continue towards Düzce. It will pass through the Altunçay and Dokuzdeğirmen Villages of Düzce Province, cross the Sakarya provincial border approximately 7 km west of the Cumayeri District of Düzce Province, and follow the Soğuksu, Rüstemler, and Göktepe neighborhoods, ending in the Dağdibi neighborhood of Adapazarı District at the current Dağdibi Pig Station. The routes of both Phase-1 and Phase-2 BOTAŞ pipelines are illustrated in Figure 3-25.

The EIA studies were completed, and the EIA report of the West Black Sea Phase-2 pipeline was disclosed in 2022. Construction works of the Phase 2 pipeline will include stripping the topsoil, excavating the pipeline trenches along the route, using explosions where hard rock loosening is needed, placing the pipes, filling the trenches with the excavated material, and covering them with stored topsoil.

Although TPAO/TP-OTC and BOTAŞ are under the jurisdiction of the same Ministries, their governing structure is different. They are working autonomously due to the legislative responsibilities of each company clearly defined as separate. As their management systems are independent from each other, a protocol to enable collaborative management of the environmental, health, safety, and social (EHSS) issues for the SGFD was signed.

The Western Black Sea Phase-2 Pipeline ("BOTAŞ Phase-2 Pipeline"), is assessed separately, and a distinct E&S Assessment Report is prepared for it, as was done in Phase 1 ESIA process. Consequently, the Phase 2 ESIA does not include any evaluation related to the BOTAŞ Phase 2 Pipeline.

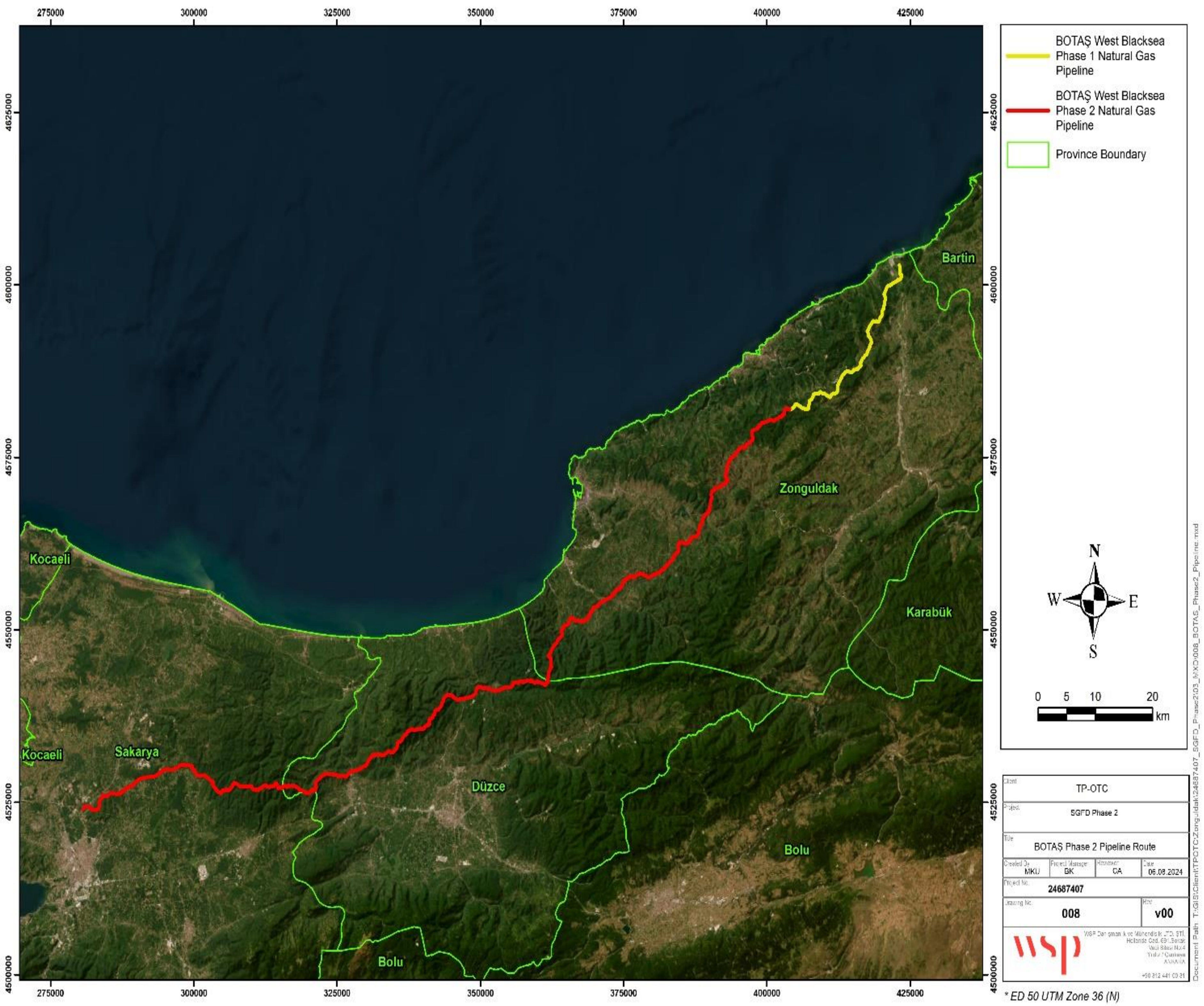

Figure 3-25: BOTAŞ Phase 1 and Phase 2 Pipelines

3.3 Project Rationale

Energy is one of the most basic and driving requirements of a country's economic and social development. In this respect, "Energy Security" is one of the vital elements of economic security and national security. Energy is an indispensable input for almost all processes necessary to sustain our social lives; It is used in industry, transportation, housing and commercial sub-sectors. While the energy consumed in the world today is obtained from many energy sources; Fossil resources such as oil, natural gas and coal constitute approximately 82.3% of these resources.[1]

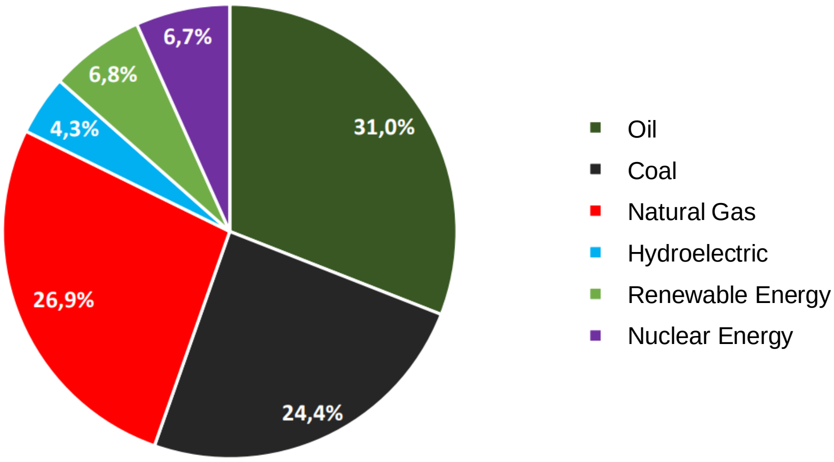

Figure 3-26: Global Primary Energy Consumption Rates in 2022[2]

As a strategic primary energy source, natural gas, the use of which is spreading rapidly in the world and in Türkiye, is rapidly taking the place of other fossil energy sources. Natural gas is an energy source that is more environmentally friendly than other fossil energy sources, pollutes the air less than other fossil fuels, and is less harmful to nature. Natural gas is preferred significantly due to its high calorific value and other qualities. It provides energy saving as it is more suitable for automatic control during combustion. Compared to many alternative fuels, its cheapness, ease of use, lack of stocking problems, etc. advantages have increased the demand for natural gas rapidly.

When the energy consumption trends in Türkiye according to their sources are examined, it is seen that the primary energy supply was mainly oil and coal before the 1980s. With the commissioning of natural gas in 1987, natural gas consumption has increased rapidly over the years. Given Türkiye's natural gas consumption amounts in 2010-2023, it is seen that the consumption amount that was 37,411million Sm^3 in 2010 increased to 50,211 million Sm^3 in 2023. Thus, the natural gas consumption increased by 34.2% in 2010-2023. National natural gas consumption amounts by years are given in Table 3-3.[3]

[1] TPAO, 2021 Oil and Natural Gas Sector Report, 2021

[2] BP, 2021 Statistical Review of World Energy, 2022

[3] TR. Energy Market Regulatory Authority (EPDK), Natural Gas Market 2023 Sector Report, 2023

Table 3-3: Total Natural Gas Consumption Amounts in Türkiye by Years (Billion Sm^3)

Year	Consumption (billion Sm^3)	Change from previous year (%)
2010	37,411	6.22
2011	43,697	16.8
2012	45,242	3.53
2013	45,918	1.5
2014	48,717	6.1
2015	47,999	-1.47
2016	46,480	-3.16
2017	53,857	15.87
2018	49,204	-8.64
2019	45,286	-7.96
2020	48,261	6.57
2021	59,854	24.02
2022	53,195	-11.13
2023	50,211	-5.62

With its developing economy, Türkiye is among the world's major energy consumers. When the sectoral distribution of 2020 is calculated as a percentage; residential consumption is 33.79%, consumption for electricity generation is 27.72%, and industrial consumption is 24.48%. This distribution, which also covers other basic sectors, can be seen in Figure 3-27.[4]

[4] TR. Energy Market Regulatory Authority (EPDK), Natural Gas Market 2023 Sector Report, 2023

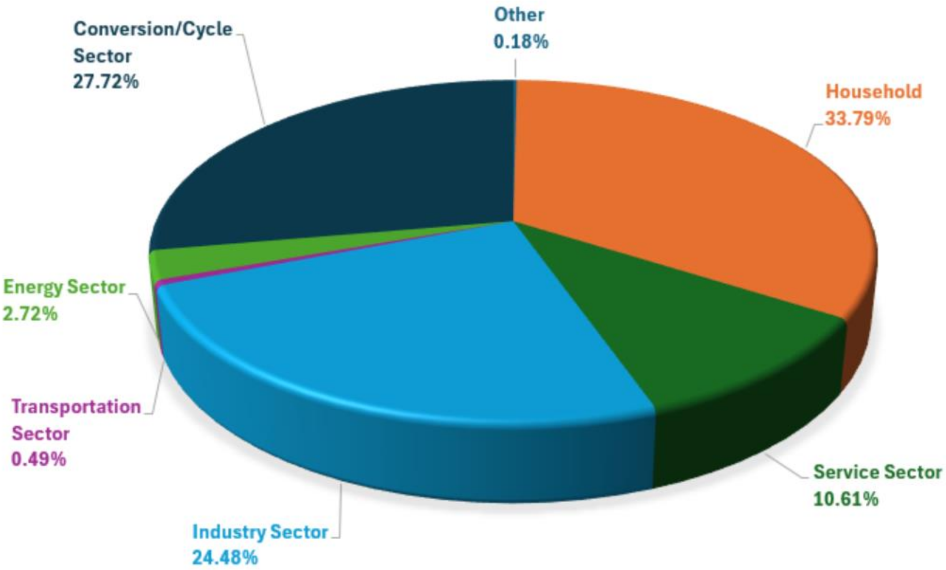

Figure 3-27: 2023 Natural Gas Sectoral Consumption Distribution in Türkiye (%)

Türkiye is a country that is heavily dependent on imports of natural gas. The rate of foreign dependency in natural gas consumption is higher than oil, and approximately 98.43% of Türkiye's natural gas consumption is met by imports. While approximately 50.2 billion m³ of natural gas was consumed in Türkiye in 2023, only 1.57% of this amount (788 million Sm^3) was met by domestic production. Most of the imports come from Russia. Distribution of natural gas imported by Türkiye in 2023 by source countries is shown in Figure 3-28.

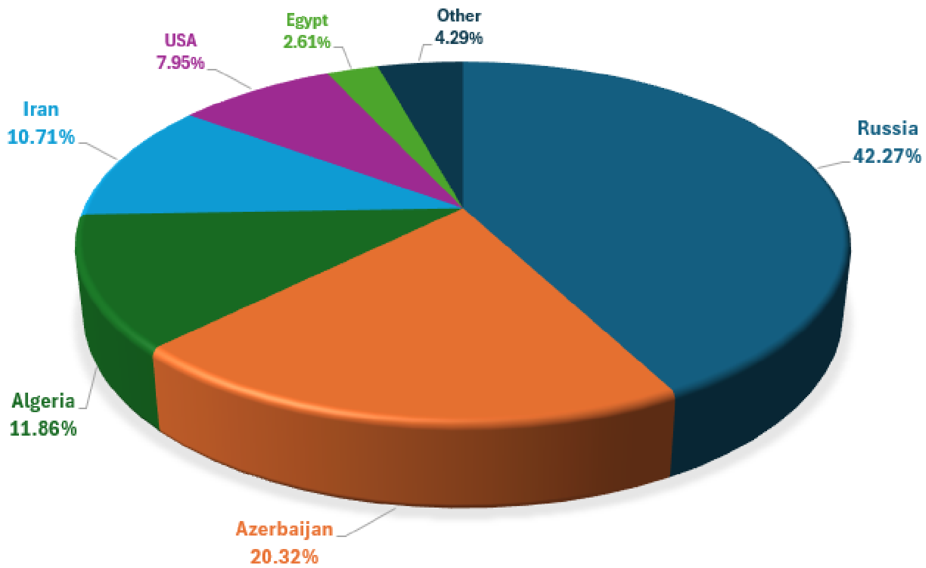

Figure 3-28: Share of Imported Natural Gas by Source Country in 2023

The Blue Stream Natural Gas Pipeline and TurkStream Gas Pipeline between Russia and Türkiye, the natural gas pipeline between Iran and Türkiye, Trans-Anatolian Natural Gas Pipeline Project (TANAP) between

Azerbaijan and Türkiye were built and put into operation for supply through pipeline. TANAP and TurkStream Gas Pipelines also reach Europe over Türkiye and contribute to meet Europe's natural gas demand.

Natural gas import has become mandatory for Türkiye due to the fact that domestic reserves and production amounts remain at very limited levels in order to meet the current and potential use of natural gas, whose usage rate and areas are increasing due to the advantages it has in parallel with the increase in energy demand.

However, a shortage of supply is encountered frequently due to political issues or technical problems. Due to these reasons arising from suppliers and transit countries and technical reasons, Türkiye has faced with situations where natural gas supply was realized below the daily gas contract values, especially in winter, and thus difficulties were experienced in maintaining the daily supply-demand balance.[5]

Offshore exploration activities, which were accelerated in order to increase the rate of meeting Türkiye's increasing oil and natural gas demand with domestic production, gave its first results with the natural gas reserve detected in the Sakarya Gas Field in 2020.

Production within the scope of SGFD Phase 1 commenced at a rate of up to 10 million Sm^3/day, equivalent to approximately 3.5 billion Sm^3 annually. Currently, the production capacity has reached over 6 million Sm^3/day. With the completion of Phase 2, the capacity is projected to increase to 20.5 million Sm^3/day, or roughly 7.5 billion Sm^3 annually, which will account for approximately 15% of Türkiye's total annual natural gas consumption. With the realization of the Phase 2 Project, Türkiye will be able to use its own resources more in the near future, and thus, will decrease the share of energy in total importation significantly and make great contributions to the country's economy.

3.4 Project Parties

- **TPAO:** Investor, responsible for exploration and drilling activities, operation processes will be taken over by TPAO
- **TP-OTC:** Project owner, subsidiary of TPAO, responsible for conducting Project Management and EPCI for the Project, operator of subsea and onshore facilities.
- **Sakarya Gas Field Development Directorate:** Project executor under the Frame Agreement between TPAO and TP-OTC.
- **BOTAŞ (Petroleum Pipeline Corporation):** state-owned crude oil and natural gas pipelines and trading company in Türkiye, responsible for design, construction and operation of the FMS and the BOTAŞ pipelines.
- **Subsea Integration Alliance (SIA) & Saipem Consortium:** EPCI Contractor of the SGFD Phase 2 Project including OneSubsea, SubSea7, Saipem, and Schlumberger.

[5] TR. Energy Market Regulatory Authority, 2023, Natural Gas Market 2023 Sector Report

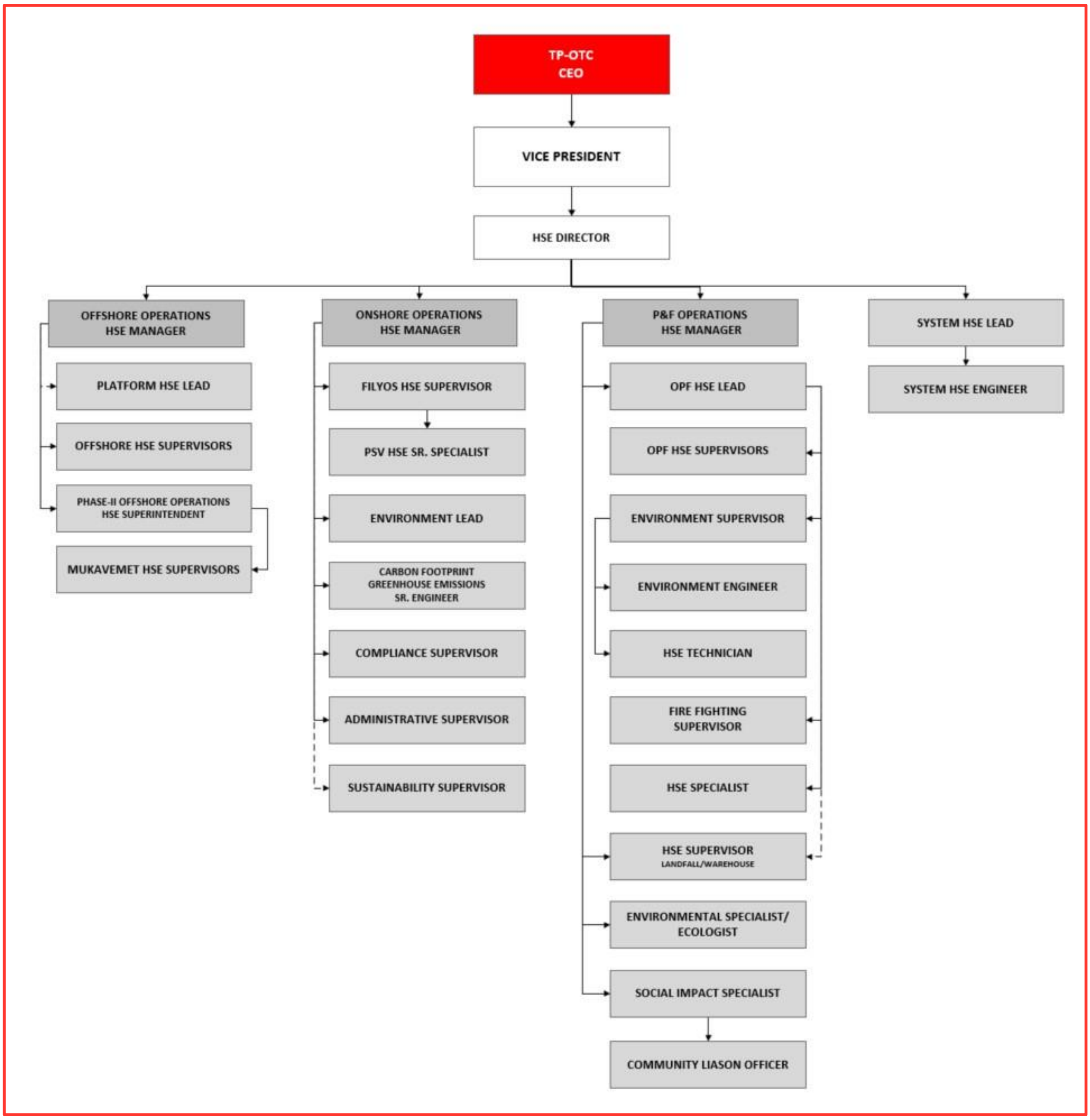

Figure 3-29: TP-OTC Project Organization Chart

Main contractors responsible for the engineering, procurement, construction and installation works are listed below.

Table 3-4: Project Main Contractors and Scope of Works

Contractor	Scope of Work
Baker Hughes	Design, supply, and installation of lower and upper completions. Consulting and supervision during well completions. Ensure compatibility for monitoring and control of the subsurface system.

Contractor	Scope of Work
Schlumberger (SLB)	Design, supply, and installation of flowback equipment for upper completion. Perforation, Gravel Pack equipment installation for lower completion. Design and execution of Perforation, Gravel Pack and Flowback operations Consulting and supervision during upper completions.
OneSubsea	Design, supply, and installation of subsea production systems (SPS). Provide internal tree caps, Christmas trees (XTs), tubing hangers, and subsea control systems. Responsible for subsea control system input to data transfer requirements.
SubSea7 (SS7)	Design, supply, and installation of infield SURF systems from wells to gathering manifold and from subsea gathering manifold to central manifold. Responsible for subsea tie-ins with spools and support for the trunkline and riser systems. Responsible for the design and installation of riser systems of FPU. Lead development of control systems and umbilicals design. Installation of the FPU mooring system. Develop field lay-out and incorporate data from FPU Contractor and TP-OTC into design. Responsible for pigging facilities and flow assurance assessments.
Saipem	Design, supply, and installation of export pipeline. Perform stress analysis and ensure monitoring of the CP system during the EPC phase. Responsible for temporary and permanent cathodic protection for onshore pipeline Sections.
FPU Contractor	Responsible for the design of riser hang-off and balcony configuration. Integration of supplied hardware into FPU topsides. Pre-commissioning, tie-in, and commissioning of the subsea control system. Responsible for telecommunications design. Responsible for the design of pigging arrangement in line with operational philosophy, including pigging equipment for use during the operational phase. Responsible for the design of the FPU mooring system.

3.5 Project Schedule

The representative draft schedule shared by TP-OTC for the Project is presented in Figure 7. According to the schedule, the construction of the export pipeline and the SPS is expected to be completed in 2025. The FPU vessel is anticipated to arrive at the Sakarya Gas Field, with connections to the SURF and SPS expected to be completed in early 2026. The connection of the processed gas to the BOTAŞ grid is targeted for 2nd half of 2026. Phase 2 (Project) schedule is depicted in Figure 3-30.

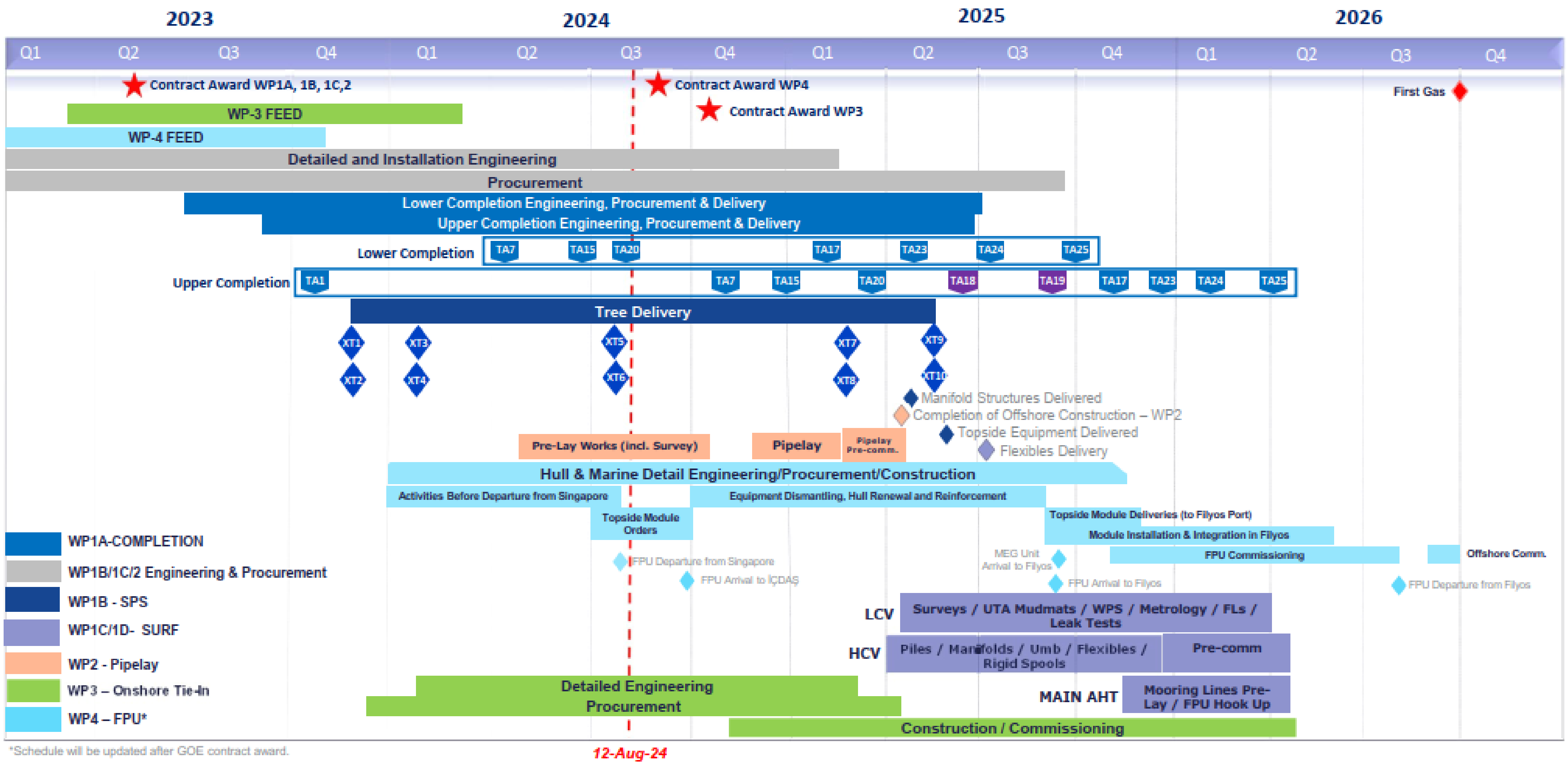

Figure 3-30: Phase 2 (Project) Schedule

3.6 Project Location and Land Ownership

The onshore facilities of the Project will be located in Zonguldak City, Çaycuma District, 25 km from Zonguldak city centre and 15 km from Çaycuma district centre beeline. The nearest settlement to the SGFD site is Sazköy Village, which is located at approximately 300 meters east.

SGFD is bounded by:

- North: Black Sea
- Northeast: Coastal Logistics Centre
- East: Sözköy Village
- West: Filyos River and Filyos Industrial Zone (under construction)
- South: Derecikören Village
- Southeast: Aşağıihsaniye Village

Figure 3-31 provides the distance of the Project facilities from the closest settlements.

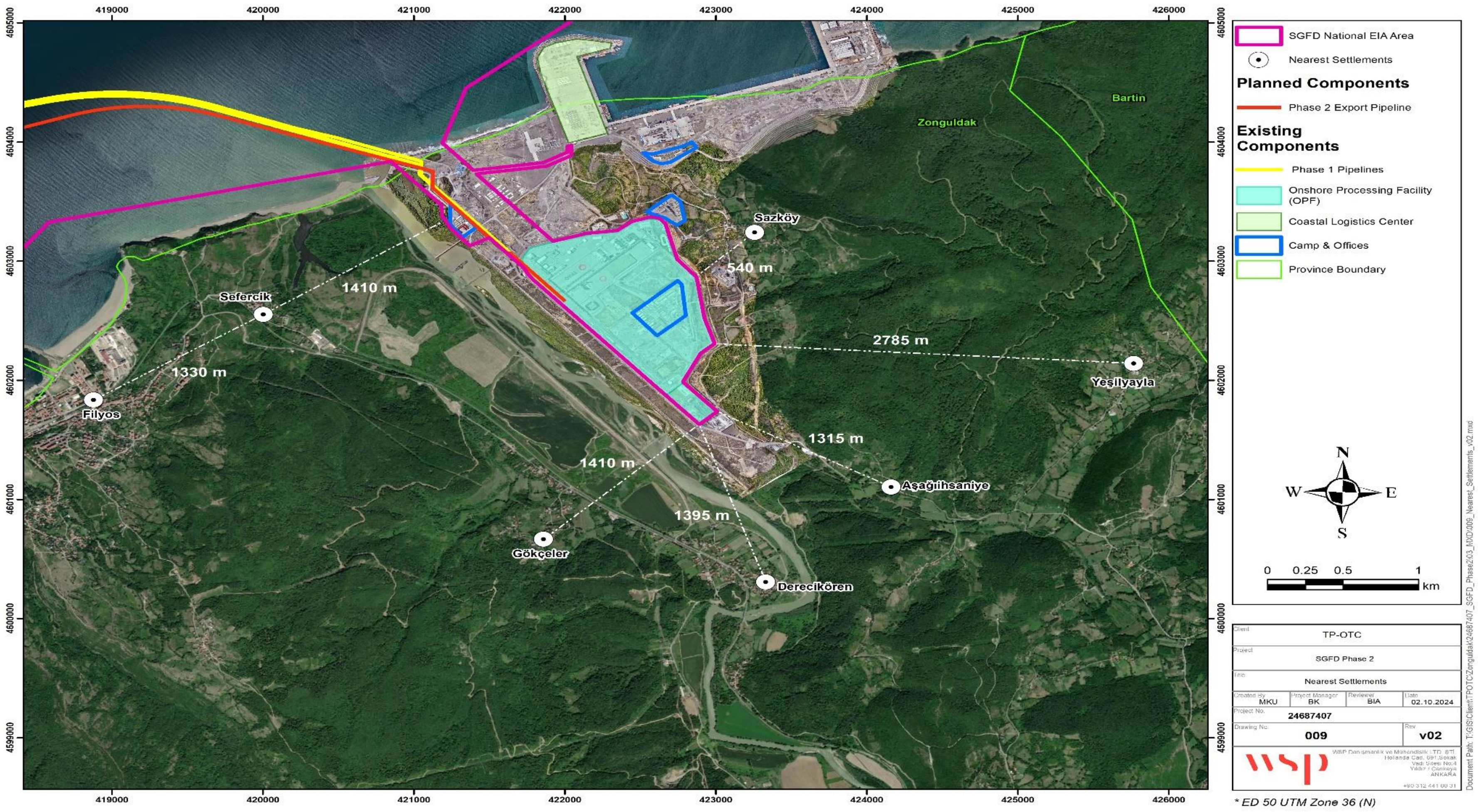

Figure 3-31: Nearest Settlements Map

The ownership status of the onshore and offshore areas of the Project is summarized below:

- TPAO has obtained a usage permit for 347,664.39 m² on the land side and 133,019.43 m² on the seaside. These permits, issued by the General Directorate of National Property, are valid for 30 years.
- The land side of the coastal edge line of the Project consists of the onshore processing facility located in the area allocated to the Project in the Industrial Zone, and a portion of the seabed cordon and pipelines located in the area between the coastal edge line and the boundary of the area allocated to the OPF.
- The area between the shoreline and OPF, where the SURF and Phase 2 pipeline passes through, is partly in the industrial zone and partly in the area where the right of easement was given in favour of the Turkish Ministry of Industry and Technology. Right of easement was granted by General Directorate of National Real Estate to TPAO for 30 years for the Project, with the consent of Ministry of Industry and Technology. With the Presidential Decree No. 5071 published in the Official Gazette dated 6 January 2022, this area was removed from the Filyos Industrial Zone area and allocated to TPAO as a special economic zone. Previous and current status of the land is illustrated in Figure 3-32. The Phase 2 onshore pipeline, which will be a continuation of the offshore pipeline, will pass through this allocated land.
- The onshore portion of the seabed cordon and pipelines pass partially through the Industrial Zone and partially through the area granted easement rights in favor of the Ministry of Transport and Infrastructure and designated as coastal logistics center in the zoning plans.OPF is located in the Industrial Zone according to the 1/100.000 scale Environmental Plan of Zonguldak-Bartın-Karabük Planning Region, and 1/25.000 scale Environmental Plan, 1/5.000 scale Master Plan and 1/1.000 scale Implementation Zoning Plan of Zonguldak province. 96.6 hectares of land has been allocated for this area.

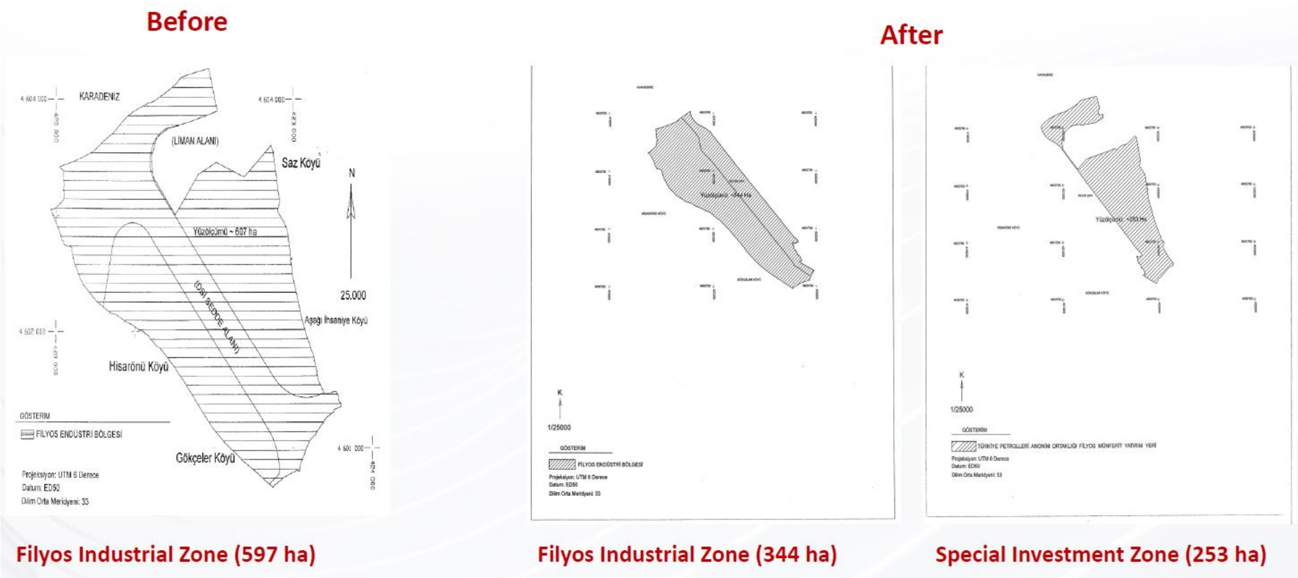

Figure 3-32: Previous and Current Land Status of the Filyos Industrial Zone and TPAO Special Investment Zone

The part of the SGFD located on the seaside of shore edge line (onshore stretch of the Phase 1 SURF: MEG pipeline + gas pipeline and Phase 2 pipeline) is situated within the state-owned lands, and the utilization permit for the area up to the boundary of territorial waters have been obtained from the Directorate General of National Property.

In the Project's offshore Section, subsea production system, subsea umbilicals and one side of the pipelines are located in Türkiye's territorial waters with a width of 12 nautical miles, while the other part is located in Türkiye's exclusive economic zone. The entire subsea production system is located over approximately 170 km offshore, at a depth of approximately 2,200 m, within the Türkiye exclusive economic zone. Türkiye's right of usage for the territorial waters located on the seaside of the Project is set out in the Territorial Waters Law. TPAO is not required to acquire any lands in this area.

The onshore part of the Project site was used as a stockpile area during the construction of Filyos Port before it was declared an industrial zone. After the area was declared as special investment zone and EIA Positive Decision for Phase 1 was obtained, pre-easement of this land was granted to TPAO.

The existing roads will be used in the Projects' construction phase and no new access road is planned.

3.7 Labor and Working Conditions

Phase 2 construction works will include the construction of the export pipeline within approximately 12 months, followed by the construction of the SPS, SURF, FPU integration, and pre-commissioning works, which will also take approximately 12 months. These activities will occur in different periods and will not be simultaneous. Construction activities are expected to be performed over 25 days per month, for 16 hours a day (2 shifts).

Production activities will continue as they currently do, for 12 months, 30 days a month, and 24 hours a day (3 shifts).

Onshore

It is planned that approximately a total of 515 personnel will be involved in the onshore **construction** activities. 24 staff will be working onshore **operation** stage, dedicated to FPU.

Vessels

The maximum crew capacity for each vessel to be used during **construction** is presented in Table 3-8, totalling to 2,818 maximum crew capacity.

Vessels during **operation** are the PSVs and maintenance vessels. It is assumed that the PSV will have 18 crew members, operating 3 times a week.

FPU

During **construction**, it is anticipated that 1,980 people will be working during the FPU reactivation stage (installation of top site equipment) at Filyos Port.

In the **operation** phase of the Phase 2 Project, it is planned to employ a total of 156 personnel, of which 132 of them will work on the offshore FPU and 24 of them will be additional to the current personnel of existing OPF.

Temporary Worker Accommodation

During **construction**, a large proportion of the workforce are/will be accommodated in the pre-existing camps & offices located within TP-OTC facilities that were established during the Phase 1.

Details about the campsites are given in Section 3.8.

During **operation,** the accommodation structure in the FPU is designed for 140 people, where 132 crew is anticipated onboard during operation. Details regarding the accommodation facilities in the FPU are given in 3.2.3.2.

3.8 Camp Sites

The pre-existing camp and office areas located within TP-OTC facilities remained from the Phase 1 construction works will be used for camps during the construction phase of Phase 2. Additionally, there is an area belong to TP-OTC that includes social facilities and VIP containers for guests. Information about the existing camps and capacity of each camp is given below.

- TP-OTC O&M Camp site: 178
- TP-OTC Contractor Campsite: 600
- Landfall Campsite: 150

Campsites are fully equipped with:

- Accommodation with water and electricity supplies
- Office buildings
- Boundary fences/walls with gate, security office and traffic barrier
- Toilets and washrooms
- Kitchens and cold storage for food
- Dining rooms
- Laundry
- Medical treatment room
- Recreation facilities
- Offices with telephones, data and postal services
- Diesel generators
- External lighting to roads and walkways
- Waste accumulation and storage area
- Wastewater treatment plants
- Water treatment units
- Emergency muster point

Most of the installed housing units are prefabricated containers on pre-installed concrete sleepers and connected to the pre-installed water and sewage lines and electric cabling. All campsites are within the security zone, fenced, lighted and guarded. Locations of the campsites and the social facilities are shown in Figure 3-33.

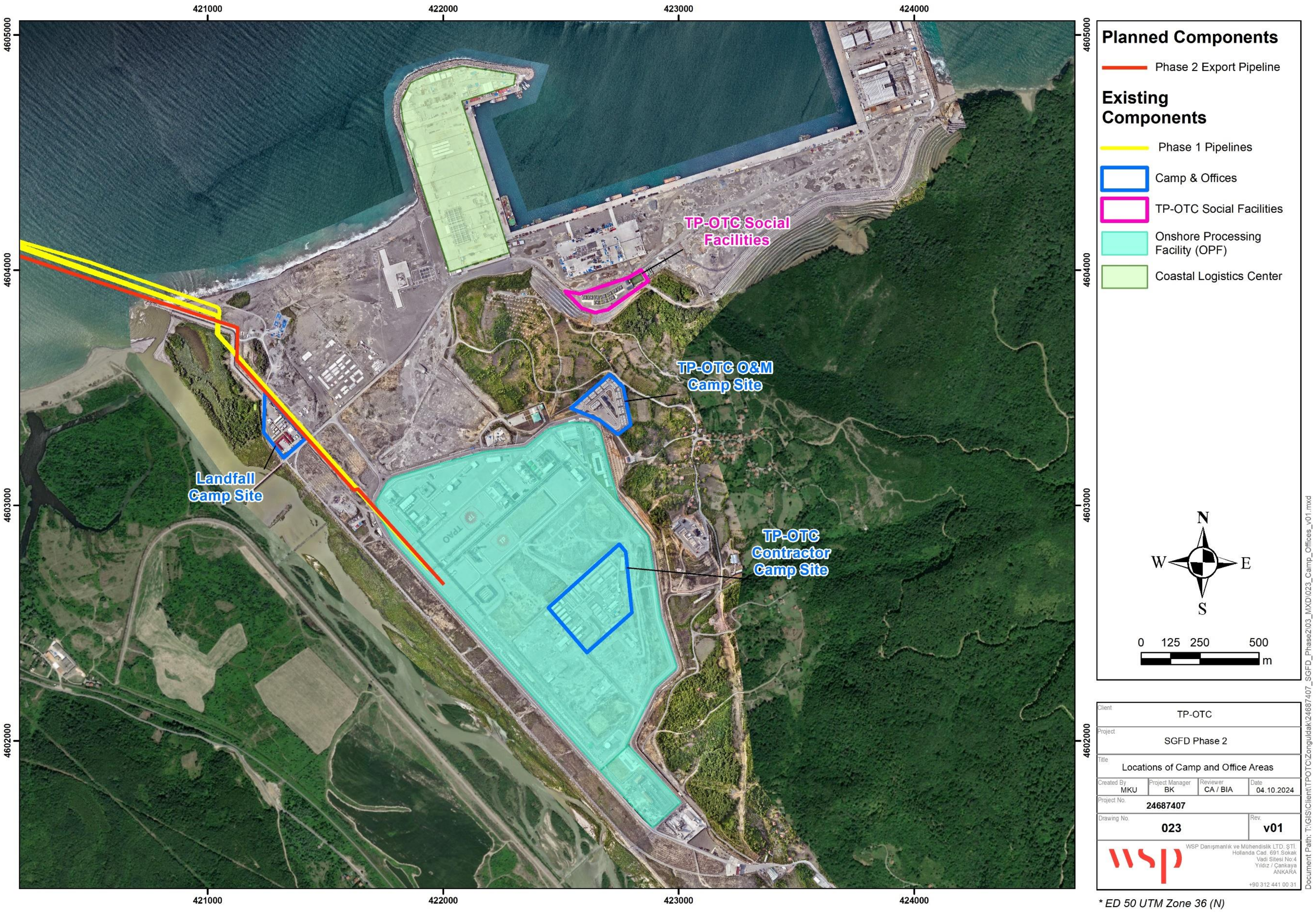

Figure 3-33: Locations of Camps & Offices

Utilities associated with the camp facilities areas include:

- Power – Construction camps' energy need are/will be supplied by the national electricity network.
- Water – The drinking water of the personnel will be bottled water. The potable water and any water needed for construction purposes will be supplied from Filyos and Saltukova Municipalities, stored in water tanks and distributed through potable water infrastructure.
- Sewage – Domestic wastewater generated by personnel at the campsites will continue to be collected by sewage infrastructure and treated in package wastewater treatment plants that have been/will be established by contractors and subcontractors exceeding the legal limit (84 people) and the treated wastewater will be discharged to Filyos River during construction phase.
- Drainage – The drainage system within the construction camp area has been designed to collect the runoff water and discharge it into the Filyos River after proper outlet structures to prevent off-site sediment transport.
- Waste disposal area – Temporary waste storage areas are allocated within each camp site for collection, segregation and temporary storage prior to transport offsite.
- Hazardous materials storage – An area are/will be allocated within each campsite for safe storage of hazardous materials.
- Fuel – Camps will use diesel as fuel for electric generators (emergency case) and construction vehicles and propane, LNG and diesel for boiler system
- Heating – Each camp site has its own heating center and alternatively each room has AC heating. AC heating is used for on-site office containers.
- Medical – There are/will be infirmaries of each contractor. Also, Health Center established by TPAO at the south entrance of the Project site will be utilised in case of need.

3.9 Resource and Infrastructure Requirements

3.9.1 General

Waste Management Facilities

The existing licensed waste management infrastructure including landfills and other recycling/recovery facilities in Zonguldak City is given below.

Table 3-5: Waste Management Facilities in Zonguldak

Facility Type	Number
Landfill Facilities (Municipality)	1
Licensed Collection, Sorting Facilities and Recycling Facilities	12
Hazardous Waste Recovery Facilities	1
Waste Oil Recovery Facility	0
Vegetable Waste Oil Recovery Facility	0
Waste Battery and Accumulator Recovery Facility	0
End-of-life Tire Recovery Facility	0
End-of-Life Vehicle Temporary Storage Areas	0
End-of-Life Vehicle Processing Facility	0
Medical Waste Sterilisation Facility	1
Non-Hazardous Waste Recovery Facility	14
Waste Electrical and Electronic Equipment Processing Facility	0
Mine Waste Disposal Facility	0
Waste Oil Refining Plant	0
Coastal Waste Receival Facility*	3

Source: Zonguldak Provincial Environmental Status Report for 2022, 2022 (zonguldak-ilcdr-2022-20230906093456.pdf (csb.gov.tr)).

*There are 3 coastal waste receival facilities in Zonguldak Province whose are operated by Zonguldak Turkish Hard Coal Enterprise General Directorate, Ereğli Iron and Steel Factories Inc. and Eren Energy Electricity Generation Inc. In addition, BER Environmental Logistics Inc., operating under the port operation of the Zonguldak Turkish Hard Coal Enterprise General Directorate has 2 waste receiving ship.

Wastewater Infrastructure

Urban wastewater management facilities in Zonguldak are listed below.

Table 3-6: Urban wastewater Management Facilities in Zonguldak

Settlement	Treatment Facility	Capacity (m^3/day)
Filyos	Deep Sea Discharge	**1,850**
Çaycuma	Wastewater Treatment Plant	**3,950**
Central District	Wastewater Treatment Plant	34,000
Kdz. Ereğli	Wastewater Treatment Plant	59,875.20

Settlement	Treatment Facility	Capacity (m^3/day)
Devrek	Wastewater Treatment Plant	8,000
Gülüç	Deep Sea Discharge	1,400
Alaplı	Deep Sea Discharge	3,924
Nebioğlu	Wastewater Treatment Plant	200

Source: Zonguldak Provincial Environmental Status Report for 2022, 2022 (zonguldak-ilcdr-2022-20230906093456.pdf (csb.gov.tr)).

3.9.2 Construction Phase

3.9.2.1 Materials

Table 3-7: Onshore Section Construction Materials and Estimated Quantities

Material	Quantity
Onshore Construction	
Crushed limestone (bedding-padding)	4,000 tons
Cement (DSM)	12,500 tons
Ready-mixed concrete (bored pile)	8,442 m^3
Stone	107,000 tons

The material needed for the construction activities, including bedding, back padding and concrete will be provided from companies which have permits/licenses in accordance with national regulations.

3.9.2.2 Vessels

Information on vessels utilized during construction is presented in Table 3-8 .

Table 3-8: The Vessels to be Utilized During Construction Phase of Offshore and Coastal Crossing Sections

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Power (kW) (BHP)
Offshore section	Well completion	Drill Ship	DS Yavuz	1	365	200	Available	43,200 kW
	Well completion	Drill Ship	DS Kanuni	1	365	200	Available	42,000 kW
	Drilling activities only	Drill Ship	DS Fatih	1	365	200	Available	43,200 kW
	Drilling until the beginning of 2026, well completion after the beginning of 2026 (until the end of the project)	Drill Ship	DS Abdülhamid Han	1	365	200	Available	48,000 kW
	Pipelay barge for near shore	Pipe Lay Barge	Castoro10	1	58	187	Yes (min WD 5m)	5x800 KW (main generators)
	Pipelay vessel for Offshore	Pipe Laying DP 3 Vessel	Castorone	1	128	702	Yes	8x8,400 kW
	Structures installation, surveys and LBL set up	MSV	Normand Frontier	1	44	100	Enwa RO unit MT25TSRH (15m3 /day) Evaporator 14 m3/day)	2x3,500 kW
	Castoro 10 support	SV	MV Neta	1	17	9	N/A	4x478 kW
	Castoro 10 support	TB	Britoil 71	1	17	15	N/A	2x3,634 BHP

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Power (kW) (BHP)
	Pipes transportation to C10	Tug boat	Fort	1	17	8	N/A	2x2,206 kW
	Castoro 10 support	Multycat	Ledekol	1	12	5	N/A	2,200 BHP
	Perform rock dumping at defined areas	Rock Dumping	Simon Steven	1	130	TBD	N/A	4x3,350 kW
	Perform prelay surveys for C10 and support C10 with Touch Down point monitoring	Survey Vessel	Denar	1	56	7	N/A	-
	TA7 and TA15 Umb and Flex lay	Flex lay Vessel	7Pacific	1	25	100	Reverse Osmosis Plant - Hatenboer Water – Demitec SW 8040/2 Duplex. 2 x 25m3/day.	2x3,360 kW 2x3,840 kW
	It will operate for material and need supplies.	Suply Vessel	DS Platform Supply Vessel (Korkut, Altan, Osman Bey, Hakan İlhan etc. or similar)	2	160	18	NIL	2x2,030 kW
	Project mob and Interim Mob	Flex lay Vessel	7Seas	1	210	110	Available	6x3,240 kW (Diesel electric)

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Power (kW) (BHP)
	Mob and Interim Mob during campaign	Rigid pipe vessel	7Vega	1	40	110	Available	3x3,500 kW 3x4,000 kW
	TA7 and TA15 Survey / Mudmat instal / FL's Inst / Pre-com	LCV - Mukavemet	LCV - Mukavemet	1	50	100	Available	3x1,686 kW
Coastal Crossing Section	Project mob and Interim Mob	7Pacific - Flex lay Vessel	1	1	15	100	Reverse Osmosis Plant - Hatenboer Water – Demitec SW 8040/2 Duplex. 2 x 25 m^3/day.	2x3,360 kW 2x3,840 kW
	Dumping operations	Split Barge	Doku 3	1	113	4	N/A	235 kW
	Dumping operations	Split Barge	Doku 7	1	136	4	N/A	235 kW
	Dregder Operastions	Becho Dredger	Burak UDHB	1	136	9	N/A	2x450 BHP
	Support tug , personnel transfer	Tug Boat	Gulsun Ana	1	137	4	N/A	2x555 kW
	Mob and Interim Mob during campaign	LCV - Mukavemet	LCV - Mukavemet	1	10	100	N/A	3x1,686 kW
	Project mob and Interim Mob	Flex lay Vessel	7Seas	1	50	110	Available	6x3,240 kW (Diesel electric)
	Mob and Interim Mob during campaign	Rigid pipe vessel	7Vega	1	15	110	Available	3x3,500 kW 3x4,000 kW

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Power (kW) (BHP)
	Dumping operations	Split Barge	Klepe-6	1	62	4	N/A	330 kW
	Dregder Operations	Becho Dredger	Rota Nehir	1	63	6	N/A	3x 330 KW
	Dumping operations	Split Barge	Rota Osman	1	62	4	N/A	315 BHP
	Support tug for pipe laying ops.	AHT	Aras Salvor	1	22		N/A	4x1590 KW
	Excavation and dumping operations	Hopper Suction	Erk Tarama-1	1	55	21	N/A	1x1081 KW 1x1165 KW
	Support boat , personnel transfer	Service Boat	Albatros	1	139	2	N/A	2x208 BHP
	Bathymetry Survey operations	Service Boat	Yunus-6	1	223	2	N/A	2x170 BHP

The vessels to be used during the construction phase of the Project will operate with diesel fuel. The amount of the fuel needed was calculated as approximately 544 tonnes/day according to Table 3-9. Support vessels will be used for refuelling of ships and waste receival.

Table 3-9: Fuel Consumption Calculations of the Vessels to be used during Construction

Vessel Type	Vessel Name	Number of Vessels	Engine Power (kW)	Engine Power (BHP)	K (g/BHP*hour)	Duration of Use (days)	Total Fuel Consumption (tonnes/day)	Fuel Type
Drill Ship	DS Yavuz	1	43,200	57,800	100	365	33.21	MGO (Marine Gas Oil)

Vessel Type	Vessel Name	Number of Vessels	Engine Power (kW)	Engine Power (BHP)	K (g/BHP*hour)	Duration of Use (days)	Total Fuel Consumption (tonnes/day)	Fuel Type
Drill Ship	DS Kanuni	1	42,000	56,280	100	365	22.27	MGO (Marine Gas Oil)
Drill Ship	DS Fatih	1	43,200	57,800	100	365	34.90	MGO (Marine Gas Oil)
Drill Ship	DS Abdülhamid Han	1	48,000	64,320	100	365	29.06	MGO (Marine Gas Oil)
Pipe Lay Barge	Castoro10	1	5x800			58	6.40	MGO (Marine Gas Oil)
Pipe Laying DP 3 Vessel	Castorone	1	8x8,400			128	in shallow water 110 ton/day in deep water: About 70-85 ton/day St-by DP "during project preparation: 40-50 tons/day Stand-by offshore WoW: 50 ton/day Mob /demob off shore: 50 ton/day Consumption in port: 17 – 20 ton/day Transit 95 – 105 ton/day weather permitting	DMA (Distillate Marine Fuel)
MSV	Normand Frontier	1	2x3,500	4,600		44	service speed (11,5 kn) – 25 ton/day eco speed (9,2 kn) – 12,7 ton/day DP ops – 17 ton/day port – 3 ton/day	DMA (Distillate Marine Fuel)
SV	MV Neta	1	4x478	2564		17	0.83	MGO (Marine Gas Oil)
TB	Britoil 71	1		2x3634		17	1.27	MGO (Marine Gas Oil)

Vessel Type	Vessel Name	Number of Vessels	Engine Power (kW)	Engine Power (BHP)	K (g/BHP*hour)	Duration of Use (days)	Total Fuel Consumption (tonnes/day)	Fuel Type
Tug boat	Fort	1	2x2,206			17	0.97	MGO (Marine Gas Oil)
Multycat	Ledekol	1		2200		12	0.43	MGO (Marine Gas Oil)
Rock Dumping	Simon Steven	1	4x3,350			130	40.00	MGO (Marine Gas Oil)
Survey Vessel	Denar	1	2x285			56	0.06	MGO (Marine Gas Oil)
Flex lay Vessel	7Pacific	1	2x3,360 2x3,840	2 x 4,502 2 x 5,145	300g/BHP/Hour	25	Transit 50[m³], DP 26[m³] Harbour 8[m³]	MGO (Marine Gas Oil)
Suply Vessel	DS Platform Supply Vessel (Korkut, Altan, Osman Bey, Hakan İlhan etc. or similar)	2	2x2,030	2x 2722		160	10.00	MGO (Marine Gas Oil)
Flex lay Vessel	7Seas	1	6x3,240 kW (Diesel electric)	6 x 4,345 BHP	8.5 g/BHP*hr engine actual NOx emission value	210	Transit 45[m³], DP 25[m³] Harbour 10[m³]	MGO (Marine Gas Oil)
Rigid pipe vessel	7Vega	1	3x3,500 3x4,000	3 x 4,693 BHP 3 x 5,364 BHP		40	Transit 45[m³], DP 17[m³] Harbour 8[m³]	MGO (Marine Gas Oil)

Vessel Type	Vessel Name	Number of Vessels	Engine Power (kW)	Engine Power (BHP)	K (g/BHP*hour)	Duration of Use (days)	Total Fuel Consumption (tonnes/day)	Fuel Type
LCV - Mukavemet	LCV - Mukavemet	1	3x1,686			50	8.00	MGO (Marine Gas Oil)
Flex lay Vessel	7Pacific	1	2x3,360 2x3,840	2 x 4,502 2 x 5,145	300g/BHP/Hour	15	Transit 50[m³], DP 26[m³] Harbour 8[m³]	MGO (Marine Gas Oil)
Split Barge	Doku 3	1	235	315		113	0.07	MGO (Marine Gas Oil)
Split Barge	Doku 7	1	235	315		136	0.06	MGO (Marine Gas Oil)
Becho Dredger	Burak UDHB	1		2x450		136	0.13	MGO (Marine Gas Oil)
Tug Boat	Gulsun Ana	1	2x555			137	0.09	MGO (Marine Gas Oil)
LCV - Mukavemet	LCV - Mukavemet	1	3x1,686			10	8.00	MGO (Marine Gas Oil)
Flex lay Vessel	7Seas	1	6x3,240 kW (Diesel electric)	6 x 4,345 BHP	8.5 g/BHP*hr engine actual NOx emission value	50	Transit 45[m³], DP 25[m³] Harbour 10[m³]	MGO (Marine Gas Oil)
Rigid pipe vessel	7Vega	1	3x3,500 3x4,000	3 x 4,693 BHP 3 x 5,364 BHP		15	Transit 45[m³], DP 17[m³] Harbour 8[m³]	MGO (Marine Gas Oil)
Split Barge	Klepe-6	1	330			62	0.04	MGO (Marine Gas Oil)

Vessel Type	Vessel Name	Number of Vessels	Engine Power (kW)	Engine Power (BHP)	K (g/BHP*hour)	Duration of Use (days)	Total Fuel Consumption (tonnes/day)	Fuel Type
Becho Dredger	Rota Nehir	1	3x330			63	0.22	MGO (Marine Gas Oil)
Split Barge	Rota Osman	1		315		62	0.05	MGO (Marine Gas Oil)
AHT	Aras Salvor	1	4x1,590			22	0.36	MGO (Marine Gas Oil)
Hopper Suction	Erk Tarama-1	1	1x1,081 1x1,165			55	0.79	MGO (Marine Gas Oil)
Service Boat	Albatros	1		2x208		139	0.50	MGO (Marine Gas Oil)
Service Boat	Yunus-6	1		2x170		223	0.48	MGO (Marine Gas Oil)

3.9.2.3 Onshore Equipment

Table 3-10 provides equipment list to be utilized for the landfall construction works during the construction phase of the Project.

Table 3-10: Equipment List

Equipment	Number
Landfall and Pipeline Construction	
Roller	1
Concrete Pump	1
Excavator	2
Loader	1
Paywelder	2
Grader	1
Hi-Up	1
Side Boom	3
Generator	1
Truck	2
Tractor	1
JCB	1
Crane	1
Low-Bed	1
Concrete Mine Truck	1

3.9.2.4 Infrastructure

Electricity

During the construction phase of the Project, it is planned to meet the electricity demand by means of the local electricity grid.

The diesel fuel to be used in the construction phase during emergency cases will be brought to the Project site by road tankers having necessary permissions and licenses. Specific supply areas are established to supply fuel to the vehicles. These areas are designed with prevention measures to protect surface waters, ground waters and surface water drainage lines. The diesel fuel brought to the area will be stored inside tanks. Secondary containments having 110% of the fuel capacity of the tanks will be placed under the fuel tanks to store the fuel to prevent spills to the environment.

Offshore Section – Water Supply and Consumption

During the construction phase, some vessels will be equipped with desalination equipment to obtain utility water. Support vessels will supply water to the vessels that are not equipped with desalination equipment. Drinking water will be supplied from local vendors in demijohns.

It is assumed that a maximum of 2,818 crew will be employed in the vessels, during Phase 2 in the offshore Section during the Project construction phase. Water demand per capita is estimated as 223 L/person day based on 2022 data of TUIK (Turkish Statistical Institute) Municipal Water Statistics. As such, the water consumption per day is calculated as follows:

Water demand of the personnel = 2,818 individuals x 223 L/person day = 628,414 L/day = 628.4 m³/day

The water consumptions of the vessels that will be used in offshore section during the construction phase are given in Table 3-11 below.

For pre-commissioning activities of the offshore section of the gas export trunkline and infield flowlines will be filled with seawater. Approximately 42,523 m³ seawater will be used. Seawater will be supplied from an intake structure (water winning spread) that will be located at Filyos Port quayside.

Table 3-11: Water Consumption Data for the Vessels to be used in the Offshore Section during the Construction Phase

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Water Demand (m^3/day)
Offshore section	Well completion	Drill Ship	DS Yavuz	1	365	200	Available	44.6
	Well completion	Drill Ship	DS Kanuni	1	365	200	Available	44.6
	Drilling activities only	Drill Ship	DS Fatih	1	365	200	Available	44.6
	Drilling until the beginning of 2026, well completion after the beginning of 2026 (until the end of the project)	Drill Ship	DS Abdülhamid Han	1	365	200	Available	44.6
	Pipelay barge for near shore	Pipe Lay Barge	Castoro10	1	58	187	Yes (min WD 5 m)	41.7
	Pipelay vessel for Offshore	Pipe Laying DP 3 Vessel	Castorone	1	128	702	Yes	156.5
	Structures installation, surveys and LBL set up	MSV	Normand Frontier	1	44	100	Enwa RO unit MT25TSRH (15m3 /day) Evaporator 14 m3/day)	22.3
	Castoro 10 support	SV	MV Neta	1	17	9	N/A	2.0
	Castoro 10 support	TB	Britoil 71	1	17	15	N/A	3.3
	Pipes transportation to C10	Tug boat	Fort	1	17	8	N/A	1.8
	Castoro 10 support	Multycat	Ledekol	1	12	5	N/A	1.1

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Water Demand (m³/day)
	Perform rock dumping at defined areas	Rock Dumping	Simon Stevin	1	130	47[6]	N/A	10.5
	Perform prelay surveys for C10 and support C10 with Touch Down point monitoring	Survey Vessel	Denar	1	56	7	N/A	1.6
	TA7 and TA15 Umb and Flex lay	Flex lay Vessel	7Pacific	1	25	100	Reverse Osmosis Plant - Hatenboer Water – Demitec SW 8040/2 Duplex. 2 x 25m3/day.	22.3
	It will operate for material and need supplies.	Suply Vessel	DS Platform Supply Vessel (Korkut, Altan, Osman Bey, Hakan İlhan etc. or similar)	2	160	18	NIL	4.0
	Project mob and Interim Mob	Flex lay Vessel	7Seas	1	210	110	Available	24.5
	Mob and Interim Mob during campaign	Rigid pipe vessel	7Vega	1	40	110	Available	24.5
	TA7 and TA15 Survey / Mudmat instal / FL's Inst / Pre-com	LCV - Mukavemet	LCV - Mukavemet	1	50	100	Available	22.3
	Project mob and Interim Mob	Flex lay Vessel	7Pacific	1	15	100	Reverse Osmosis Plant - Hatenboer Water –	22.3

[6] Assumed based on publicly available data on vessel's crew numbers.

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Water Demand (m³/day)
Coastal Crossing Section							Demitec SW 8040/2 Duplex. 2x25 m^3/day.	
	Dumping operations	Split Barge	Doku 3	1	113	4	N/A	0.9
	Dumping operations	Split Barge	Doku 7	1	136	4	N/A	0.9
	Dregder Operastions	Becho Dredger	Burak UDHB	1	136	9	N/A	2.0
	Support tug , personnel transfer	Tug Boat	Gulsun Ana	1	137	4	N/A	0.9
	Mob and Interim Mob during campaign	LCV - Mukavemet	LCV - Mukavemet	1	10	100	N/A	22.3
	Project mob and Interim Mob	Flex lay Vessel	7Seas	1	50	110	Available	24.5
	Mob and Interim Mob during campaign	Rigid pipe vessel	7Vega	1	15	110	Available	24.5
	Dumping operations	Split Barge	Klepe-6	1	62	4	N/A	0.9
	Dregder Operations	Becho Dredger	Rota Nehir	1	63	6	N/A	1.3
	Dumping operations	Split Barge	Rota Osman	1	62	4	N/A	0.9
	Support tug for pipe laying ops.	AHT	Aras Salvor	1	22	20[7]	N/A	4.5

[7] Crew number is assumed based on similer vessel information.

Field of Activity	Construction Activity/purpose of activity	Vessel Type	Vessel Name	Number of Vessels	Duration of Use (days)	Max. Crew Capacity	Desalination Equipment	Water Demand (m^3/day)
	Excavation and dumping operations	Hopper Suction	Erk Tarama-1	1	55	21	N/A	4.7
	Support boat, personnel transfer	Service Boat	Albatros	1	139	2	N/A	0.4
	Bathymetry Survey operations	Service Boat	Yunus-6	1	223	2	N/A	0.4

Onshore Section – Water Supply and Consumption

- Potable water needs of the personnel:

The personnel who will work in the onshore construction phase and FPU reactivation will need drinking and utility water. A maximum of approximately 2,500 people (515 + 1480) will be employed during Phase 2 construction phase. Water demand per capita is estimated as 223 L/person day based on 2022 data of TUIK (Turkish Statistical Institute) Municipal Water Statistics. As such, the water consumption per day is calculated as follows:

Water demand of personnel = 2,500 individuals x 223 L/person day = 557,500 L/day ≈ 557.5 m³/day.

The drinking water of the personnel will be bottled water. The potable water needed for construction purposes and personnel needs at the construction camps will be supplied from Filyos Municipality by water tankers and from the municipality water network for offsite accommodation.

- Water needs for dust suppression during dry periods:

Any water need for construction purposes will be provided from Filyos Municipality by water tankers.

- Water needs for fire extinguishing:

Any water needed for construction purposes will be provided from Saltukova Municipality by water tankers.

- Pre-commissioning activities:
- For pre-commissioning activities of the onshore section of the export pipeline will be filled with potable water. Approximately, 2,850 m^3 potable water will be used. The potable water will be supplied from Filyos or Saltukova Municipalities.

Onshore and offshore water consumption during construction are summarised below:

Table 3-12: Summary of Indicative Water Use During Construction Phase

Project activity	Water requirements		
	Water supply source	Water amount	Supply Period
Construction Phase			
Domestic potable water (onshore)	Filyos Municipality Offsite accommodation: Municipality water network	Total: 557.5 m^3/day, calculated according to 2,500 people during peak construction period (the amount includes offsite accommodation)	Throughout the onshore construction
Domestic potable water (offshore vessels)	N/A	628.4 m^3/day	Throughout the offshore construction
Dust suppression	Filyos Municipality	140 m^3/day	During dry season
Fire extinguishing	Saltukova Municipality	N/A	Throughout the onshore construction

Project activity	**Water requirements**		
	Water supply source	**Water amount**	**Supply Period**
Pre-commissioning (Onshore)	Potable water	2,850 m^3	During onshore pre-commissioning activities
Pre-commissioning (Offshore)	Sea water	42,523 m^3	During offshore pre-commissioning activities

N/A: Not provided as of this report

Stormwater

The drainage system within the construction camp and construction facilities area will be designed to collect the runoff water and discharge it into the Filyos River after proper outlet structures to prevent off-site sediment transport.

Traffic

The existing roads will be used and no road is planned for the construction or operation phase of the Project.

3.9.3 Operation Phase

3.9.3.1 Materials

Utilization of any materials other than the materials to be used in the maintenance and repair operations is not expected during the operating phase.

Chemical injection system is provided inside the FPU to supply chemicals as required by the wells, subsea infrastructure, and process facilities. Chemicals will be injected both at the subsea wells and within the facility to efficiently process fluids, improve performance and help meet product specifications or protect the equipment and lines from corrosive elements. Chemical tanks on FPU are presented in Table 3-13.

Table 3-13: Chemical Tanks on FPU

Compartment	**Volume (m^3)**
NaOH Tank	496.0
Na_2CO_3 Tank	1,333.0
Lean Meg Tank	33,275.0
Back UP Tank	23,406.0
Rich MEG Tank	35,127.6
Subsea Methanol Storage Tank	48.0
Topsides Methanol Storage Tank	24.0
Scale Inhibitor Storage Tank	3.2
Corrosion Inhibitor Storage Tank	6.4

3.9.3.2 Equipment

Onshore Section - Equipment

The use of equipment other than that intended for the maintenance and repair of existing components is not anticipated during the operation phase.

Offshore Section – Equipment

The use of equipment other than that intended for the maintenance and repair of existing components is not anticipated during the operation phase.

Vessels

Logistical support for the FPU will be provided by platform supply vessels (PSVs), ensuring the continuous supply of goods, consumables, and personnel. Similar to ship features supporting drilling ships (Korkut, Altan, Osman Bey, Hakan İlhan etc.) may be utilized if maintenance or repairs are required during the operational phase.

3.9.3.3 Infrastructure

Onshore Section – Electricity

The national electrical grid will be the primary energy source for camps and offices. Also, the emergency generators powered by diesel fuel will be available inside the facility.

It is anticipated that there will be no additional electricity demand for the onshore part of the Phase 2.

Offshore Section – Electricity

The Floating Production Unit (FPU) is powered primarily by three steam turbine generators (STGs), each rated at 10 MW, providing a total capacity of 30 MW, though typically only two are required to meet maximum load demands. These STGs generate power at 6.6 kV, 3 phase, 60 Hz, and are driven by steam from deck-mounted boilers, with exhaust cooled by seawater-cooled condensers. Power is distributed to auxiliary consumers through step-down transformers at 440V or 220V. For backup power, there are three essential diesel generators, each rated at 1.2 MW, providing a total of 3.6 MW at 440V, and one emergency diesel generator rated at 750 kW, also at 440V. These generators ensure essential power generation and black start capability, while additional features like uninterruptible power supplies (UPS) and battery backups support critical systems and emergency operations. The FPU's power demand ranges from 8.77 MW to 10.46 MW, depending on the use of high-pressure compressors.

Onshore Section – Water Supply and Consumption

The units/processes that will need water during the operation phase are listed below. The volumes are estimates and will be finalized during the design stage.

- Potable water for the personnel;

24 people additional to the existing personnel of the SGFD will be employed during operation phase of Phase 2. Water demand per capita is estimated as 223 L/person day based on 2022 data of TUIK Municipal Water Statistics. As such, additional water consumption per day due to the realization of Phase 2 is calculated as follows:

Maximum water demand of personnel = 24 individuals x 223 L/person day = 5,352 L/day = 5.4 m^3/day

The drinking water of the personnel will be bottled water. The potable water needed for operation purposes and personnel needs will be supplied from groundwater following a treatment. As of October 2024, there are 3 potable treatment plans operated by TP-OTC to comply with potable water quality standards defined in Appendix C.

- Fire-fighting water:

The Firefighting System consisting of two fire water storage tanks, each is sized to provide a minimum of 6 hours supply based on fire system design case of 4,000 gpm will be used for also during Phase 2 operation. Each tank has a capacity of 5,572 m^3.

The potable water, utility water, process water, and fire-fighting water will be supplied by the permitted groundwater well. The raw water will continue to be treated at Demineralized and Potable Water Generation Package and distributed to the network. The pre-treatment system shall have backwashing and regeneration requirements of activated carbon filter, multimedia filter and ultrafiltration systems.

Indicative water use during the operation phase is summarized below.

Table 3-14: Indicative Water Use During Operation Phase

Project activity	Water requirement		
	Water supply source	Water amount	Supply Period
Operation Phase			
Domestic potable water	Groundwater	5.4 m^3/day (calculated according to 24 individuals)	Throughout the operation
Firewater tanks		N/A	Will be used during emergencies
Total		5.4 (m^3/day)	

Offshore Section – Water Supply and Consumption

Vessels

During the operation phase, PSVs will serve to FPU 3 times a week, with a crew capacity of 18. The water demand for PSV operations has been calculated by estimating per capita water consumption at 223 liters per person per day, based on 2022 data from the Turkish Statistical Institute (TUIK) Municipal Water Statistics:

Water demand of PSV crew = 18 individuals x 223 L/person.day x (3day/7day) = 1,720 L/day ≈ 1.7 m^3/day.

FPU

Seawater will be the sole water source for the process. It is estimated that, the FPU will withdraw a total of 294,000 m^3/day of seawater, 144,000 m^3/day for power generation cooling and 150,000 m^3/day for topside equipment (MEG Regeneration) cooling, for the operational needs using five pumps running at 20% capacity each, with an installed capacity of 352,800 m^3/day.

For the vessel needs, the FPU will withdraw 18,000 m³/day using one pump at 100% capacity, with an installed capacity of 36,000 m³/day. The total withdrawal including power generation cooling, topside equipment cooling and vessel needs amount to approximately 312,000 m³/day.

The personnel who will work on FPU will need drinking and utility water. A maximum of 132 people will be employed on board. Water demand per capita is estimated as 223 L/person day based on 2022 data of TUIK (Turkish Statistical Institute) Municipal Water Statistics. As such, the water consumption per day is calculated as follows:

Water demand of personnel = 132 individuals x 223 L/person day = 29,436 L/day ≈ 29.4 m³/day.

Fresh water used on the ship will also be obtained from seawater at a rate of 90 m³/day using a Reverse Osmosis (RO) unit, with an installed capacity of 180 m³/day for the crew consumption and the boiler feed water needs. The FPU is equipped with a freshwater bunkering facility as a backup to the RO units, though it needies not anticipated to be used.

Table 3-15: Sea Water Useage (FPU Operation)

Type	Usage Area	Technical Details	Maximum Capacity Required (m³/day)
Cooling Water	Power generation turbines	Maximum demand, based on two turbines running at full capacity	144,000
Cooling Water	MEG regeneration (Topside)	Required to cool down maximum volume of Rich MEG Feed	150,000
Ship-Sourced Water	General ship operations (various smaller heat exchangers including HVAC and coolers for lube oil on rotating equipment)	Installed capacity is 36000 m³/day (1x100% pump running, 1x100% pump standby).	18,000
Freshwater Production	Crew consumption and boiler feed water	Produced via onboard RO	90
Total			**312,090**

- Firewater:

The fire-fighting water system for the FPU will consist of two independent, 100% capacity pumps designed to meet the fire-fighting water and foam demand. Each pump will be powered by an autonomous diesel system, including a hydraulically driven lift pump, diesel engine, hydraulic power unit (HPU), booster pump, and local control panel, housed within a protective enclosure. The pumps will be strategically located at opposite ends of the FPU (one forward and one aft) to prevent common mode failure and ensure operational redundancy. These pumps are situated in safe zones and are protected against fire and explosion loads.

- Stormwater

Offshore

The open drain system on FPU will consist of bunding, drip trays, drain pots/boxes, fire seals, piping and valves, pumps, as necessary to collect and safely dispose rainwater, firewater, deck wash, spills and leaks. Separate and physically segregated (no cross connection) drain systems will be provided for areas classified as hazardous and non-hazardous.

The Open Hazardous Drain will collect rainwater, green water (if relevant), firewater and accidental spills from areas classified as hazardous. No continuous streams will be routed to the open hazardous drain system. Collected liquids will be drained by gravity or pumped to the slop tank.

The Open Non-Hazardous Drain is a system of drains originating from non-hazardous areas, typically utility areas, e.g. E-House module, Seawater Treatment or Utility Module. The Open Non-Hazardous Drain will collect rainwater, green water, firewater and other liquids originating from the non-hazardous areas. Water drained from non-hazardous modules will be routed through a liquid seal/fire seal before entering the Open Non-Hazardous Drain header. The Open Non-Hazardous Drain header will lead drained water to the dirty slop tank.

Traffic

The roads to access to the Project site will be the same used during the construction phase.

No major regular load transfer is planned during the operation phase of the Project.

Although offshore facilities do not require any regular maintenance, vessels may operate in case of need for maintenance/repair during the operation phase. In order to ensure safety during maintenance and repair activities, a safety perimeter will be determined and Navtex announcement will be made to restrict third-party vessels entrance to the operation area.

3.10 Emission, Wastewater and Waste

3.10.1 Construction Phase

Emission

Construction activities may generate emission of fugitive dust caused by a combination of on-site excavation and movement of earth materials, contact of construction machinery with bare soil, and exposure of bare soil and soil piles to wind.

Exhaust gas emissions such as Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Hydrocarbon (HC), Particulate Matter (PM) and Sulphur dioxide (SO_2) will occur due to the diesel engines that will be used for construction equipment and vessels that will be operated during the onshore land preparation / construction activities and offshore activities.

During construction and decommissioning activities, noise and vibration may be caused by the operation of pile drivers, earth moving and excavation equipment, cranes, offshore vessels and the transportation of equipment, materials and people.

Wastewater

<u>Offshore Section</u>

Sources of wastewater to be produced during construction and pre-commissioning works at the offshore Section of the Project, as anticipated as of the date of this ESIA report, is listed below:

- Domestic wastewater due to maximum crew number in vessels;

Water demand of personnel is estimated 628.4 m³/day based on 2022 data of TUIK Municipal Water Statistics. It is assumed that all the domestic water to be used by the Project crew will be converted to domestic wastewater. As such, the wastewater generation per day is calculated as 628.4 m³/day. Domestic wastewater will be taken by waste ships and will be transferred to Zonguldak TTK Waste Reception Facility.

- Bilge water (leachate and oily wastewater) from machinery spaces in vessels;

Bilge water will be transferred to Zonguldak TTK Waste Receival Facility for disposal and will not be discharged into sea.

- Ballast and storage displacement water due to water pumped into and out of storage during loading and off-loading operations;

All ships using ballast water exchange will conduct ballast water exchange at least 50 nautical miles (NM) from the nearest land and in water at least 200 m in depth, taking into account Ballast Water Management Convention and Guidelines developed by International Maritime Organization (IMO).

- Wastewater resulting from offshore pre-commissioning activities (typically filtered seawater, or filtered seawater with chemical additives including corrosion inhibitor, oxygen scavenger, biocide, and dye to prevent internal corrosion or to identify leaks, MEG or umbilical transportation liquid). All discharges will be managed according to the permits to be obtained.

After the completion of the construction phase and before the pipelines and SPS components are put into operations, all the pipes will be pre-commissioned to detect possible faults in the junctions and prevent leakage. Such test, as described in Section 3.2.1 and 3.2.2 for SPS and SURF, respectively. Amount of wastewater resulting from pre-commissioning activities are given below.

Table 3-16: Discharges related with Pre-commissioning Activities of SPS, SURF, and Offshore Pipeline

Discharge Type	Estimated Amount (m³)
Chemically Treated Sea Water	23,699.0
Non-Chemically Treated Sea Water	18,824.0
Offshore Discharged MEG (@ 2200m WD)	191.0
Additive (RX 5255 @2200m WD)	11.3
Additive (RX 5102D @2200m WD)	1.9
Total	42,523.0

Resulting wastewater is planned to be discharged deep sea, in correspondence to the SPS site (i.e., at a depth of 2,200 m, 155 km offshore).

<u>Onshore Section</u>

Sources of wastewater to be produced during construction works at the onshore Section of the Project is listed below:

- Domestic wastewater due to personnel working at the onshore Section of the Project;

Estimated water demand per capita is provided as 223 L/person.day in 2022 TUIK (Turkish Statistical Institute) Municipal Water Statistics. It is assumed that all the domestic water to be used by the Project personnel will be converted to domestic wastewater. As such, the maximum wastewater generation per day during the construction period is calculated as 557.5 m³/day including offsite accommodation (if applicable) and construction camps. Domestic wastewater generated by personnel at the camp site will be collected by sewage infrastructure and treated in sewage wastewater treatment plants that have been established by TP-OTC. As of October 2024, there are 3 sewage treatment plants operated by TP-OTC. The generated wastewater from these plants is discharged to Filyos River in line with the environmental permit that was secured from the Provincial Directorate of Environment, Urbanization and Climate Change as per the Regulation on Environmental Permits and Licenses.

- Wastewater generated by backwashing of filters in the potable water treatment plants

There are 3 onshore potable water treatments plants operated by TP-OTC which generates backwash wastewater of approximately 106.5 m³/day calculated according to 928 people of camp capacity. Campsite capacities are not expected to be increased due to the construction phase of the Phase 2 since there are sufficient capacity in the camp sites. Treated wastewaters will be discharged to the receiving environment in line with the environmental permit to be secured from the Provincial Directorate of Environment, Urbanization and Climate Change as per the Regulation on Environmental Permits and Licenses.

Table 3-17: Wastewater Expected to be Generated During the Construction Phase and Planned Management Methods

Wastewater Source	Wastewater Type	Treatment Package	Estimated Daily Amount / Outlet Flowrate	Continuous/ Intermittent	Discharge Location	Discharge Permit*
Construction Phase						
Sewage wastewater (onshore)	Domestic	Sewage treatment plants: OPF (75 m^3/day) TP-OTC former contractor campsite area (400 m^3/day for 600 people) ACD (40 m^3/day for 150 people)	Total: 557.5 m^3/day, calculated according to 2,500 individuals during peak construction period (the amount) includes offsite accommodation WWTP Capacity: 515 m^3/day	Intermittent	Filyos River (from plants) Offsite accommodation-sewage network> licensed WWTPs	Obtained
Sewage wastewater (offshore)	Domestic	N/A	628.4 m^3/day	Intermittent	Shipped by licensed waste barge to the Zonguldak TTK Waste Reception Facility	Not required
Backwash wastewater from potable water treatment plants	Industrial – includes high TSS (Total suspended solid) may include chloride sulphate and iron, may require pH adjustment	Chemical treatment package including coagulation and flocculation	106.5 m^3/day, calculated according to 928 individuals of camp capacity, camp capacity can be increased with the increasingg number of individuals	Intermittent	Filyos River	Obtained

Wastewater Source	Wastewater Type	Treatment Package	Estimated Daily Amount / Outlet Flowrate	Continuous/ Intermittent	Discharge Location	Discharge Permit*
Wastewater from Pre-commissioning activities (onshore)	Industrial – High TSS and TDS, include chemical additives, MEG, umbilical transportation liquid	No treatment envisaged, analysis as per Project Standards before Filyos River discharge is necessary to confirm	2,850 m^3 (total)	Intermittent	Filyos River	Required
Wastewater from Pre-commissioning activities (offshore)	Industrial – High TSS and TDS, include chemical additives, MEG, umbilical transportation liquid	No treatment envisaged, analysis as per Project Standards before deep sea discharge is necessary to confirm	42,523 m^3 (total)	Intermittent	Deep sea (SPS site, at a depth of 2,200 m, >155 km offshore)	Required

* As per Regulation on Environmental Permits and Licenses.

** It is recommended to obtain opinion of the Ministry/Provincial Directorate of Environment, Urbanization and Climate Change.

Waste

General non-hazardous and hazardous wastes generated due to construction activities are mainly, municipal waste, packaging waste, waste oil, contaminated packaging wastes, hydraulic fluids, used batteries, empty paint and chemical containers, filters, fluorescent tubes, scrap metals and cables, welding waste, end-of-life tires, electrical and electronic wastes, treatment sludge, concrete sludge and medical waste. Significant additional waste stream specific to vessel operations are residues/sludge from scrubbers (exhaust gas cleaning), scrubber systems washing water, incinerator ash (if any), sludge from engine rooms, fuel tanks and/or oil sediments of vessels. Generated wastes will be stored in separate cans, drums, boxes, bags, or other containers. The wastes that fall under the scope of MARPOL 73/78 will be transported via support vessels to the TTK Zonguldak Port Waste Reception Facility. All other wastes will be sent to the onshore temporary storage area at Filyos Port before being transported to a licensed waste reception facility for disposal. Wastes generated onshore will be stored at the temporary waste storage area and then disposed of by licensed companies.

3.10.2 Operation Phase

3.10.2.1 Emission

There will not be any air emission on onshore section due to operation of Phase 2 other than the ones defined in the Phase 1 ESIA. The main sources of air emissions resulting from FPU operations in Phase 2 include: combustion emissions from power and heat generation (gas engines and boilers), operation of flare and fugitive emissions (gas/fuel oil leaks from the connection points of the pipeline and entrance/exist points of the units). Principal pollutants from these sources include nitrogen oxides, sulfur oxides, carbon monoxide, particulates, volatile organic compounds (VOC), methane and ethane and greenhouse gases. For the onshore section of Phase 2, fugitive VOC emissions is expected from the connection points of the pipeline.

During operations, the main sources of noise and vibration pollution will be produced by gas engines and rotating equipment. Noise sources include flares, pumps, compressors, generators, and heaters.

3.10.2.2 Wastewater

3.10.2.2.1 Onshore

There will not be any wastewater discharge on onshore section due to the operation of Phase 2 other than the ones defined in the Phase 1 ESIA. Sources of wastewater to be produced during the operation phase of FPU are listed below.

The only wastewater generated due to the onshore operation of Phase 2 will be domestic wastewater to be generated due to personnel. Water demand per capita is estimated as 223 L/person.day based on 2022 data of TUIK Municipal Water Statistics. It is assumed that all the domestic water to be used by the Project personnel will be converted to domestic wastewater. As such, the wastewater generation per day is calculated as 5.4 m^3/day for 24 individuals.

3.10.2.2.2 Offshore

Process-generated wastewater on the FPU will include produced water and the cooling seawater:

- Produced water is expected to reach a maximum of 773 m^3/day based on peak gas production rates, though actual volumes are anticipated to be around 500 m^3/day. Produced water will include monovalent salts.

- As explained in Section 3.9.3.3, seawater withdrawal will be a total of approximately 312,090 m^3/day for cooling water for power generation and MEG regeneration, as well as the general ship operations, crew consumption combined. In the worst case scenario, the whole volume generated will be discharged.

All of the above streams are planned to be discharged into the Black Sea after meeting the discharge standards issued by the Ministry of Environment, Urbanization and Climate Change and MARPOL. Cooling water discharge temperature will not exceed 35°C.

Table 3-18: Project Specific Discharge Standards, issued by the MoEUCC

Parameter	Unit	2 hr Composite Sample
Chemical Oxygen Demand	(mg/L)	250
Oil and grease	(mg/L)	15
Total Kjeldahl Nitrogen	(mg/L)	20
Total Phosporus	(mg/L)	2
Total Phenol	(mg/L)	2
Hydrocarbons	(mg/L)	15
Toxicity Dilution Factor (Fish Bioassay, ZSF)		6
pH		6-9

Ballast, Bilge and Slop Discharges:

Infrequent ballast water discharge will be necessary during ballast water exchange on the FPU vessel. The ballast water will be stored in Water Ballast Tanks (WBT), which are isolated from contamination sources. When discharge is required, it will be released into the sea without treatment, provided no contamination is detected. If contamination is detected before discharge, the affected ballast water will be transferred onshore via PSV for proper disposal.

The Black Sea is designated as a Special Area under MARPOL Annex I for the prevention of pollution by oil. This means that stricter regulations apply for the discharge of bilge water and slop oil in this area:

- **Bilge Water (Black Sea - Special Area): (Transferred to waste reception facilities)**
  - The bilge water must not originate from the cargo pump-room bilges.
  - The bilge water must not be mixed with oil cargo residues.
  - The ship must be proceeding en route.
  - The oil content of the discharge, without dilution, must not exceed 15 parts per million (ppm).
  - The ship must have operational oil filtering equipment that complies with Regulation 16(7) of this Annex.
  - The filtering system must be equipped with an automatic stopping device to halt discharge if the oil content exceeds 15 ppm.

- **<u>Slop Oil (Black Sea - Special Area): (Transferred to waste reception facilities)</u>**
  - The discharge of slop oil (from cargo tanks on oil tankers) is prohibited in the Black Sea, except under specific conditions.
    - If slop oil discharge is allowed, it must meet the following conditions:
    - The ship must be more than 50 nautical miles from the nearest land.
    - The ship must be en route.
    - The discharge rate must not exceed 30 liters per nautical mile.
    - The total discharge of slop oil must not exceed 1/15,000 of the total quantity of cargo for ships ≥ 70,000 GT, or 1/30,000 for smaller ships.
- **<u>Reception Facilities:</u>**
  - Ships are encouraged to use available reception facilities in the Black Sea ports for disposing of oily waste (bilge and slop oil) to avoid discharges into the sea.

In summary, the discharge of bilge water and slop oil into the Black Sea is heavily restricted due to its status as a Special Area under MARPOL, and vessels must comply with stringent standards to minimize environmental pollution.

In this regard, Project will not discharge its bilge water and slop oil to the Black Sea.

Domestic Wastewater

132 people personnel are expected to work on FPU during operation. Water demand per capita is estimated as 223 L/person.day based on 2022 data of TUIK Municipal Water Statistics. It is assumed that all the domestic water to be used by the Project personnel will be converted to domestic wastewater. As such, the wastewater generation per day is calculated as 29.4 m^3/day for 132 personnel. Domestic wastewater (sewage) generated by the personnel on FPU will be treated by a sewage treatment plant designed for 140 people on board, and then discharged into the sea.

During the operation phase, PSVs will serve to FPU 3 times a week, with a crew capacity of 18. Water demand per capita is estimated as 223 L/person.day based on 2022 data of TUIK Municipal Water Statistics. It is assumed that all the domestic water to be used by the PSV crew will be converted to domestic wastewater. As such, the wastewater generation per day is calculated as 1.7 m^3/day for 18 crew personnel working three days a week. Domestic wastewater will be taken by waste ships and will be transferred to Zonguldak TTK Waste Reception Facility.

Summary of the wastewater sources, amounts, treatment methods and discharge locations are given in below tables. Technical specifications of the treatment packages are given in Section 3.9.3. Effluent discharge limits are presented in Appendix C.

Table 3-19: Wastewater to be Generated During the Operation Phase and Management Methods (Onshore)

Wastewater Source	Wastewater Type	Treatment Package	Outlet Flowrate/ Daily Amount	Continuous/ Intermittent	Discharge Location	Discharge Permit
Operation Phase						
Demineralized and Potable Water Generation Package backwash wastewater	Backwash - includes high TSS, may include chloride sulphate and iron, may require pH adjustment	Demineralized and Potable Water Generation Package- Sedimentation Package	2.7 m^3/day (capacity 185 m^3/d)	Intermittent	Filyos River	Obtained
Sewage wastewater	Domestic	Sewage Treatment Plant	5.4 m^3/day (capacity 75 m^3/day)	Continuous	Filyos River	Obtained

Table 3-20: Amounts of Different Types of Water to be Discharged (FPU Operation)

Type of Water to be Discharged	Discharge Method
Produced Water (Based on maximum gas production and water-to-gas ratio, up to 773 m^3/day) - Including monovalent salt	Discharged to sea (after limit values are met)
Cooling water (sea water withdrawn for cooling of power generation and MEG regeneration, and ship sourced water: up to 312,000 m^3/day)	Discharged to sea after 35°C thermal requirements are met
Ship-Based Sewage (approximately 29.4 m^3/day, will be treated via a shipboard sewage treatment plant)	Discharged to sea after treatment
Bilge Water	Discharged to reception facility
Reject Oily Wastewater from Separators	Transferred to shore with PSVs
Ballast Water	Discharged to sea If contamination is detected, transferred to Zonguldak TTK Waste Reception Facility
PSV Operation Sewage (1.7 m^3/day)	Shipped by licensed waste barge to Zonguldak TTK Waste Reception Facility

Waste

Offshore Section

- Solid and liquid wastes to be generated at the FPU will include divalent salts & monovalent salts (with an expected production of respectively 29.5 tonnes/day and 35 tonnes/day of dry salts based on the maximum produced water volume), domestic wastes, production chemical wastes, laboratory chemical wastes, process equipment lubricants, and medical wastes. All solid and liquid wastes (except monovalent salt) generated from the FPU will be managed by separating at the source and transferring to shore via PSVs.

Table 3-21: Solid and Liquid Waste Generation from FPU Operation

Type of Waste	Disposal Method
Solid Food Waste (Generated onboard, includes food scraps)	Managed according to regulations
Divalent Salt (up to 29.5 t/day)	Transferred to shore for disposal
Engine Room Equipment Lubricants	Transferred to shore for disposal
Solid Waste (e.g., PPE, oily rags)	Transferred to shore for disposal
Slop Oil	Transferred to shore for disposal

Onshore Section

Any waste generation on onshore section due to operation of Phase 2 other than the ones defined in the Phase 1 ESIA is not expected.

3.11 Field Life and Decommissioning

It is foreseen that the SGFD Project will remain in operation for 25-40 years. The operating period of the Project depends on natural gas production in the Sakarya Gas Field and may extend following new explorations.

Onshore Processing Facility including all its facilities, equipment and buildings shall have a design life of 25 years. After 25 years, the operational life of the OPF can be extended with the maintenance, repair and revision works. If the production reserve runs out, production feasibility is lost, or the service life of the facility ends, the OPF will need to be removed to enable subsequent land uses. Once the Onshore Processing Facility is shut down, all the units will be removed from the site and the rehabilitation operations will commence. If needed, the site grading will be completed, taking into account the surface drainage during operations. The ground surface will be covered according to appropriate vegetation selection (compatible with the soil, climate and flora of the region) after the rehabilitation operations are completed.

The FPU topsides have a design life of 20 years, and the FPU itself has a minimum design life of 20 years on station. The life extension scope for the hull, accommodation, and marine systems ensures that no hull or accommodation steelwork renewals will be required during its full design life. All marine systems and utilities within the hull and accommodation are designed to remain operable through inspection, maintenance, and repair or replacement. After the decommissioning of the FPU at the Sakarya Gas Field, the vessel may either be sold, loaned out, or remodified for other purposes. Depending on market conditions and industry needs at the time of decommissioning, the FPU could serve as a production vessel for other fields or undergo modifications to support other offshore operations.

Post-operation alternatives are removal of the facility components and restoration of the area or leaving the components as they are in the offshore Section. Pipelines left in place will be disconnected and isolated from all potential sources of hydrocarbons; cleaned and purged of hydrocarbons; and sealed at its ends. The two main issues to consider when evaluating these alternatives are risk posing for maritime traffic in the region and environmental impacts. Since no national legislation specifically regulating these areas is available, the General Assembly resolution No. A.672 (16) of the United Nations specialized agency International Maritime Organization (IMO), of which Türkiye is a founding member, should be taken into account. This resolution, which is a recommendation to the member states, addresses the alternatives of removing or leaving the marine structures in terms of marine traffic and suggests considering the factors such as the unacceptable risks for humans and the marine environment, use these facilities as an artificial reef for the development of fishing, removal costs, and technical impossibilities in the evaluation. The resolution states that structures at a depth of a minimum of 75 meters and weighing below 4,000 tones can be removed for marine traffic. Since this criterion was intended for offshore platforms, the project does not involve any unit subjected to this limitation. With reference to the pipelines, although IMO and also other International Conventions (e.g. Kuwait Protocol, 1990; OSPAR Convention, 1992) do not apply directly to the pipelines, it is a consolidated practice to evaluate the situation "case by case" according to some main guidelines:

- For pipelines buried under the seabed a remediation process is generally carried out - for example by cleaning and making them safe from any risks (e.g. chemical contamination or danger to navigation) - and they are then abandoned in situ.
- For the pipelines emerging from the seabed, the possible options of removal (partial or total) or, after a remediation process, sinking (natural or forced) in the sediment, or coverage or mechanical protection can be considered.

In particular, most international guidelines and also national laws of European countries allow abandonment on site if this ensures a lower environmental impact than removal and it does not pose a risk to other uses of the sea.

During the decommissioning phase, operations will be carried out based on the evaluations to be performed considering the technologies, applicable legislation, and the best practices worldwide on that date.