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1 EXECUTIVE SUMMARY

This document defines the preliminary Basis of Design for the SURF and the Flexible Line relevant to Development Project. The document comprises reservoir characteristics, fluid properties and well production data. It also contains the available geomorphological and meteocean design data. The document also provides a description of the preliminary system configuration, which will be further developed by the Tenderers.

This document will be enriched and updated as necessary along the project roadmap and possibly at the beginning of each new Project phase.

2 INTRODUCTION

2.1 Development

The discovery is located in the REGION (Op. 40%, Pertamina 30%, Neptune 30%) operated by Ltd., within the Kutai basin, offshore East Kalimantan area in Borneo island - Indonesia. REGION was awarded in 22nd August 2019 with gross- split REGION terms, however the effective date is 26th January 2020.

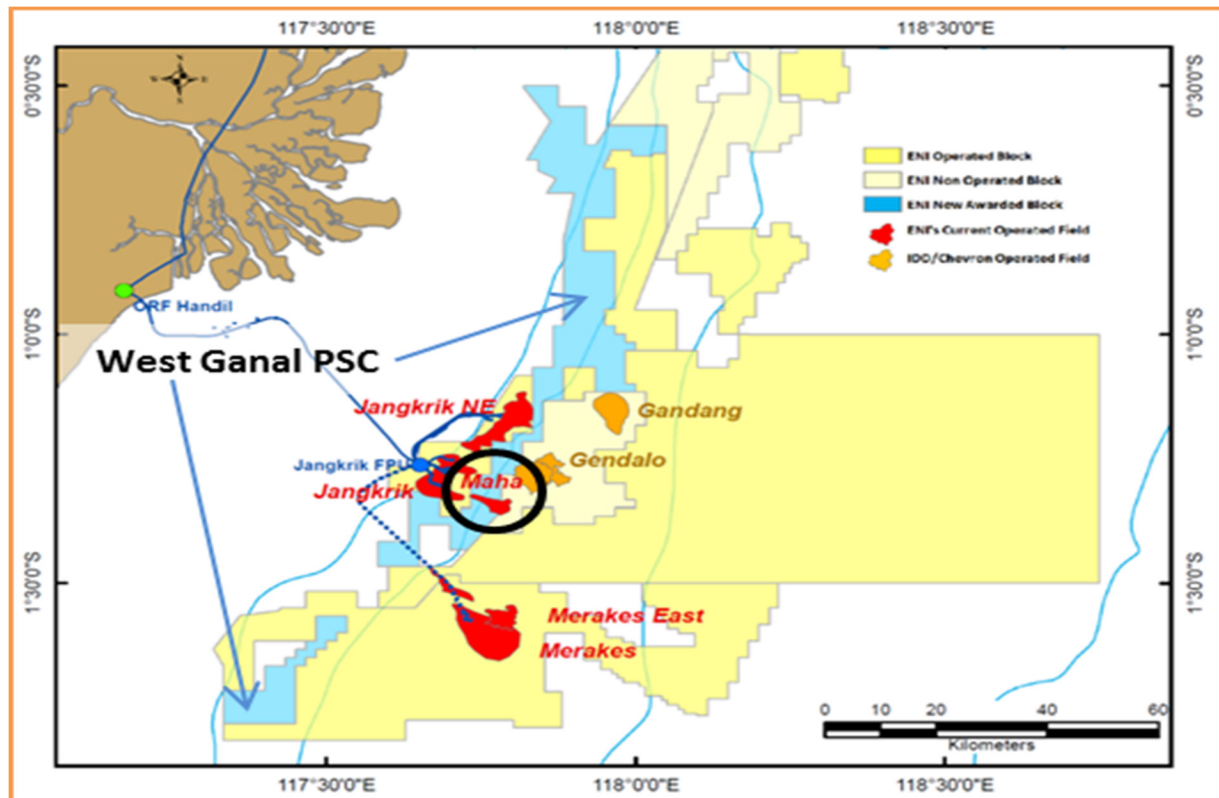


Figure 1: Location Map

-1 well, operated by Gas Brand, was spud on 21st May 2002 in water depth of -2,436 ft. The well reached a TD of 13,441 ftMD (-13,100 ftTVDSS) on 7th June 2002.

The discovery was already successfully explored by the Gendalo-4 operated by Unocal in 2001. Both wells lie to the SW of Gendalo structure from which discovery is separated by a saddle.

2.2 Development Strategy

The development concept of is subsea tie-in to the current existing Jangkrik facilities considering the available ullage at the late life of Jangkrik and the location in vicinity of Jangkrik Main Clusters.

3 LOCAL ACTS, LAWS, RULES AND REGULATIONS

3.1 Environmental Emission Limits

Refer to [7].

Should some special operations related to field (e.g. pre-commissioning activities of flowline) imply a possible impact to the environment, these will have to be properly assessed with the HSE function to verify any constraints to be satisfied.

3.2 Regulatory Compliance

Refer to [3]**Errore. L'origine riferimento non è stata trovata..**

3.3 Order of Precedence

The local acts, laws, rules and regulations applicable to this project shall be the same of those relevant to Jangkrik field.

The most stringent rules shall be applied. In the event of scope overlapping of different rules, the most stringent requirement shall apply.

The following shall be the order of precedence, 1 being the highest precedence level (see ref. [3] for complete list of applicable standards):

1. Indonesian Laws, Regulations and International Conventions signed and/or endorsed by Indonesia, applicable to offshore installations.
2. Classification Rules (as applicable to the concerned type of equipment), Flag Regulations, Marine International Rules and Certification Society.
3. Project Documentation (Appendix D)
4. Company Standards (for new equipment, last revision of Company Standards shall be used – as per ref. [3]**Errore. L'origine riferimento non è stata trovata..**).
5. International codes and standards.

4 ABBREVIATIONS, REFERENCES, CODES & STANDARDS

4.1 Abbreviations and Acronyms

The followings will be applied to this document:

API	Degree(s) API
BOPD	Barrels of Oil Per Day
BLPD	Barrels of Liquid Per Day
BWPD	Barrels of Water Per Day
CDT	Cool Down Time
CPT	Cone Penetration Test
CGR	Condensate Gas Ratio
CITV	Chemical Injection Throttling Valve
CJB	Cable Jointing Box
E&I	Electrical and Instrumentation
EJB	Electrical Junction Box
EPU	Electric Power Unit
FPU	Floating Production Unit
FTHP	Flowing Tubing Head Pressure
HC	Hydrocarbon
HIPPS	High Integrity Pressure Protection System
HP	High Pressure
HPU	Hydraulic Power Unit
ID	Internal Diameter
ILT	In Line Tee
ITT	Invitation To Tender
JKK	Jangkrik Main
JNE	Jangkrik North East
LCP	Local Control Panel
LER	Local Equipment Room
LNG	Liquefied Natural Gas
LP	Low Pressure
MEG	MonoEthylen Glycol
MeOH	Methanol
MMBLPD	Million Barrel of liquid per day
MMSCFD	Million of Standard Cubic Feet per Day
MSL	Mean Sea Level
MWA	Mid Water Arch
ND	Nominal Diameter
OD	Outer Diameter
OJB	Optical Junction Box
ORF	Onshore Receiving Facilities
P&ID	Piping and Instrumentation

PLET	Pipe Line End Termination
PLR	Pig Launcher Receiver
ppmv	Parts per Million, Volumetric
PVT	Pressure, Volume, Temperature
PW	Produced Water
RAM	Reliability Availability Maintainability
ROV	Remotely Operated Vehicle
RVP	Reid Vapor Pressure
SCM	Subsea Control Module
SDU	Subsea Distribution Unit
SDV	Shut Down Valve
SoW	Scope of Work
SI	International System of Units
SITHP	Shut-In Tubing Head Pressure
SMLS	Seamless
SPS	Subsea Production System
SURF	Subsea, Umbilical, Riser and Flowline
SSIV	Subsea Safety Isolation Valve
TBD	To be Defined
TUTU	Topside Umbilical Termination Unit
TVDSS	True Vertical Depth SubSea
TVP	True Vapor Pressure
UPS	Uninterruptible Power Supply
UTA	Umbilical Termination Unit
XT	Christmas Tree
WD	Water Depth
WHFP	Well Head Flowing Pressure
WHSIP	Well Head Shut-In Pressure
WHFT	Well Head Flowing Temperature

4.3 Definitions

The following definitions apply to this document:

FLOWLINE	Generic term adopted for hydrocarbon transportation lines that connect onshore/offshore installations (synonym of pipeline)
PIPELINE	Generic term adopted for hydrocarbon transportation lines that connect onshore/offshore installations (synonym of flowline)
SEALINE	Term referred to hydrocarbon transportation lines that connect offshore installations to shore
STABILISED CONDENSATES	Treated HC Fluid that can be stored at ambient temperature and pressure in liquid phase without significant boil-off generation.

4.4 Reference Documents

[Ref n°] Document Name	Document Number	Notes
[1] Field General Layout and Details	220814BGDP00039	
[2] Subsea Block Diagram	220814BGRB00036	
[3] International Codes and Company Standards	220814BGES00006	
[4] Deleted	Deleted	
[5] Field Development - Basis of Design	220814FGRB00011	Feasibility document
[6] Health, Safety and Environmental (HSE) Philosophy	000589_DV_CS.HSE.0048.000_01	Feasibility document
[7] Indonesian Environmental Emission Limits	000589_DV_CS.HSE.0118.000_00	Feasibility document
[8] Development – Process Report	220814FPRA00013	Feasibility document
[9] Facilities Report	220814FGRV00012	Feasibility document
[10] e-EHXT P&ID	220814BUFM00053	
[11] Control System Block Diagram	220814BGFB00037	
[12] UTA P&ID	220814BUFM00052	
[13] HIPPS P&ID	220814BUFM00047	
[14] Subsea Structure P&ID	220814BUFM00045	
[15] TEE Structure P&ID	220814BUFM00046	
[16] Corrosion Control and Material Selection report	220814BXRV00026	
[17] Flow Assurance Report	220814BBRV00014	
[18] PROJECT field development drilling & COMPLETION PRE-FEASIBILITY STUDY	COAP/SU-P-1-P-28155	Pre-feasibility study

[19]	Pre-FEED Work for IDD Concept Evaluation	GLO-D200-UFA-BOD-WPI-000-10001	
[20]	Flow Assurance Design Basis	GLO-D200-UFA-BOD-WPI-000-10001	
[21]	Flow Assurance Report	220814FPRV00014	Feasibility document
[22]	Topside Process Description	220801DPRV10009	
[23]	Phase 2 – Process Verification Report – Dual Mode Case 750 Inlet	220801BPR00329	
[24]	Jangkrik Phase 2 – FEED Process Report	220801BGRV00151	
[25]	SPS Basis of Design	RP_A11111v1 – Main (Feb 2012)	
[26]	EPCI 2 – Basis of Design	220802BGRB45230	
[27]	Basis of Design and Functional Requirements for FPU detail design	220801DGSH45183	
[28]	Basis of Design for Merakes Project	220800BGRBM1366	
[29]	Subsea System and Subsea Control System Description and philosophy	220814BURB00041	
[30]	SCS (Subsea Control System) Data Sheet	220814BUGA00056	
[31]	Umbilical System Data Sheet	220814BUGA00057	
[32]	SURF Design pressure definition and verification	220814BUCA00040	

The original engineering design documentation relevant to existing facilities are to be taken into account for the design.

4.5 Codes & Standards

As a minimum all activities shall comply with Indonesia Regulation and International & Company Standards as detailed in document ref. [3].

4.6 Units of Measurements

The following reference conditions shall be applied when needed:

Reference	Temperature [°C]	Pressure [bara]
Standard Conditions	15.56	1.013
Normal Conditions	0	1.013

Table 1: Reference Conditions

The units of measurement will be generally expressed according to S.I. except for the following differences:

Unit	Symbol	Notes
Temperature	°C	
Pressure	barg	Gauge pressure
	bara	Absolute pressure
Time	h	
Reid Vapor Pressure (RVP)	psi	
True Vapor Pressure (TVP)	psia	
Mass Flow	kg/h	
Molar Flow	kmol/h	
Energy Flow	kWe	Electric Power Low duty
	MWe	Electric Power High duty 10 ⁶ W
	MWth	Thermal Power
Gas Flow	MMSCFD	10 ⁶ SCFD
	MMSCMD	10 ⁶ SCMD
Liquid Flow	BLPD	Barrels per day at standard conditions
		1 BLPD = 0.1589873 m ³ /day
	MMBLPD	10 ⁶ BLPD
Gas quantities	BSCF	10 ⁹ SCF
Liquid quantities	MMBBL	Barrels at standard conditions
		10 ⁶ BBL
		1 MMBBLS = 158,987.3 m ³
Contaminant content	ppmv	Parts per Million, Volumetric
	mg/Nm ³	10 ⁻³ grams per normal cubic meter
Gas Oil Ratio (GOR)	SCF/BBL	At standard conditions
Reservoir permeability	mD	milli-Darcy
Fouling Factor	m ² –h °C /kcal	
Steel and concrete strength	N/mm ²	
Diameter of pipe	Inches	
Gas Flowrate	MMSCFD	

Table 2: Units of Measurement

4.7 Coordinate Grid Reference System

All reported coordinates for the project were referenced to the World Geodetic System WGS84 datum based on the WGS84 spheroid, and are projected in Universal Transverse Mercator coordinates for Zone 50 in the southern hemisphere (UTM 50 S). Units are in meters.

Project will use the same system of Jangkrik Project.

Spheroid	
Spheroid name	WGS84
Semi-major axis (a)	6 378 137.000
Semi-minor axis (b)	6 356 752.314
Inverse flattng (1/f)	298.257 223 563
Eccentricity squared (e^2)	0.006 694 380 07
Projection Parameters – EPSG 32750	
Projection name	Universal Transverse Mercator (UTM)
Projection type	Transverse Mercator
Zone	50 South
Central Meridian (CM)	117° East
Origin latitude	0° North
False Easting	500,000 m
False Northing	10,000,000 m
Scale factor at CM	0.9996
Units	Meters

Table 3: Coordinate system

5 PROJECT DESCRIPTION

5.1 Development Scenario

The Gas discovery well, -1, was drilled by Gas Brand in 2,436' water depth (Indonesia partner at 20%) and reached TD on June 7th 2002 at -13,100' TVDSS.

After un-successful proposals on the Development of and other Gas discoveries in the Area, Gas Brand released the acreage.

Indonesia earned the ownership of the exploration and exploitation rights on acreage again after successful bidding at the Indonesia's 2019 bidding round.

development represents an excellent synergy opportunity to extend the life of the Jangkrik Asset: the declining production profile in Jangkrik will enable to provide additional value and reserves to .

The project is going to provide further value to the Government of Indonesia and to the stakeholders along the gas processing and commercialization chain, from the Field to the Terminals, the Bontang LNG plant.

The development concept of is subsea tie-in to the current existing Jangkrik facilities considering the available ullage at the late life of Jangkrik and the location in vicinity of

Jangkrik Main Clusters.

The n.2 new wells are tied-back to Jangkrik Trunkline 1 by means of one new subsea production flowline, while the production of Jangkrik Cluster 1 is sent to Jangkrik Cluster 3

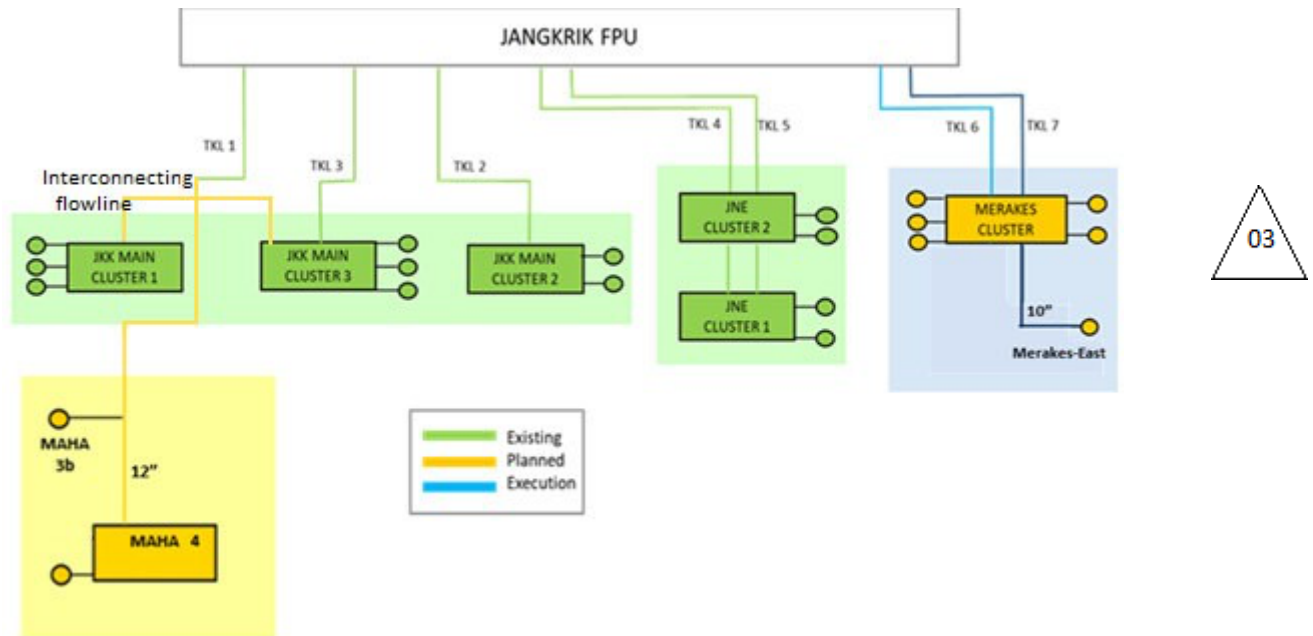


Figure 2 – Development Scenario

6 GENERAL LOCATION DATA

6.1 CLIMATOLOGY AND METOCEAN DATA

For the environmental data as seawater temperature, currents and waves, ref. to [25].

6.1.1 Water Depths

The water depths in the area ranges from 300 m to 1200 m below mean sea level.

6.1.2 Offshore Plant Location

Jangkrik FPU coordinates

Item	X [m]	Y [m]	Latitude	Longitude
FPU centre	572421	9860512	1° 15' 42,868" S	117° 39' 03,499 E

Table 4: Jangkrik FPU Coordinates

6.1.3 Onshore Plant Location

Jangkrik Existing ORF coordinates

The coordinates of the existing ORF for Jangkrik are as here described:

- Latitude: 9899144 N to 9899370 N
- Longitude: 519077 E to 519329 E

6.1.4 Enviromental Data

For the environmental data as seawater temperature, currents and waves, refer to following document (Ref.[25]):

Doc n°	Doc. title	Revision
RP_A11111v1 – Main (Feb 2012)	SPS Basis of Design	

Table 5: Metocean Data

Return periods for which oil and gas structures might be designed are set by national regulation or guidelines. For the typical return periods refer to Company Standard 28842.ENG.OFF.STD "Meteo-Oceanographic Design Basis".

6.2 GEOPHYSICAL AND GEOTECHNICAL DATA

6.2.1 Geotechnical

No geotechnical data are available for development area. A dedicated geotechnical survey will be performed in the next project phases, with the aim to define the soil characterization at the locations identified for the installation of the subsea structures, flowlines and umbilicals.

6.2.2 Geophysical

No geophysical data are available to date for development area. A dedicated geophysical survey will be performed in the next project phases, with the aim of gathering detailed information concerning the geomorphological characteristics of the seabed and the shallow subsurface. The survey results will provide detailed bathymetry, seabed features identification, shallow stratigraphy and related potential hazards.

6.2.3 Bathymetry Data

No detailed bathymetric/morphological data are available for the project area. Some preliminary information has been derived with a reprocessing of a 3D seismic volume, that provided a low resolution (12.5m x 12.5m) bathy-morphological map (Figure 3 and Figure 4). The area is characterized by several canyons (main and tributary), visible faults, steep slopes, indented profiles and also isolated mounds. Water depth in the development area ranges from 300 m to 1500 m.

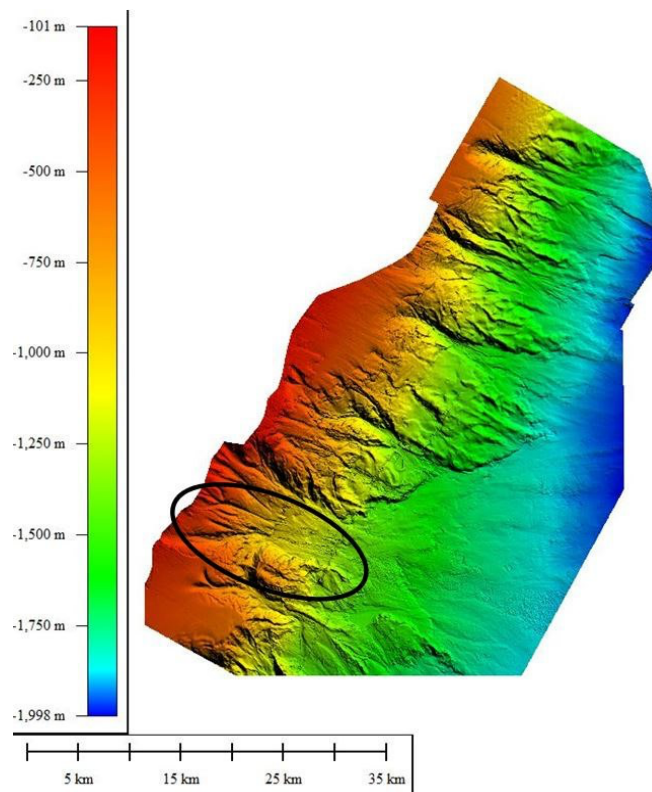


Figure 3 – General Morphology of the area derived from a 3D seismic volume. Black Circle defines the development area.

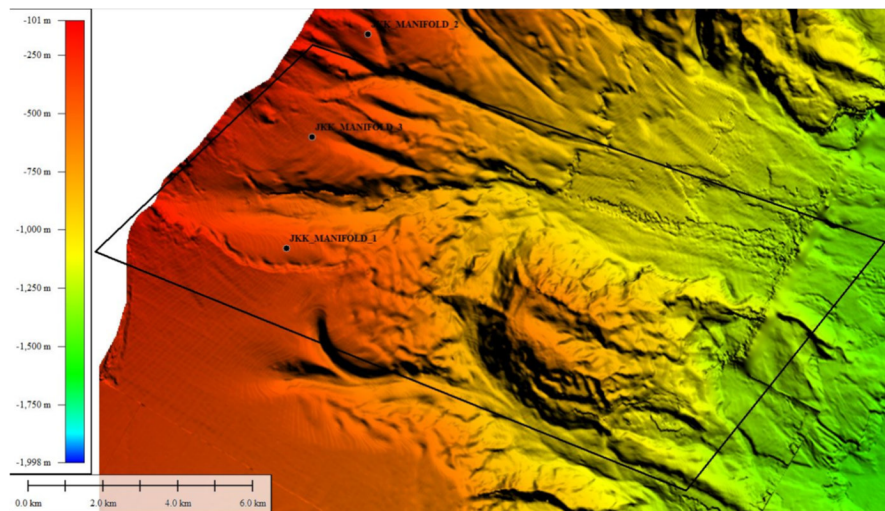


Figure 4 – General Morphology of the area derived from a 3D seismic volume. Detail of the area of interest

6.2.4 Geohazard Assessment

No geohazard studies have been performed with focus on development area.

6.2.5 Earthquake Data

ISO 19901-2 shall be considered for the design of subsea structures and foundations

7 RESERVOIR MANAGEMENT BASIS

7.1 Main Reservoir Data

The primary reservoir discovered in Field is T-090 (equivalent to 3130 based on previous Gas Brand nomenclature) and it was penetrated at a depth of approximately -2,400 to -2,600 meter subsea true vertical depth (TVDSS).

Secondary reservoirs are T-088-T-086 (equivalent to 3140 and 3150 based on previous Gas Brand nomenclature) and T-084 Segment-1 (equivalent to 3170 based on previous Gas Brand nomenclature).

field is a Pliocene turbidite deposited 3.5 million years ago as toe-of-slope fans that draped over an anticlinal structure that is part of the greater Gendalo Hub anticline. The trap at the field is stratigraphic, formed by the pinch-out of Pliocene turbidites up-dip into a slope valley.

The T-090 reservoir is the primary gas accumulation and contains approximately 74% of the total gas-in-place. The amplitude, ESP, and SpecD maps clearly show the toe-of-slope fan geometry and the opng neck of the slope valley feeding the fan from the northwest. Based on the revised depositional model is characterized by a channel-attached fan system with presence of potential barriers. The T-090 package thins up-dip into the slope valley and, while the entire package correlates well seismically, the internal stratigraphic complexities are not well defined. The depositional lobes show a compensational stacking; these events often can amalgamate laterally making difficult to define the reservoir architecture. No GWC was recognized at well locations; RMS amplitude shut off suggests a contact near to -2560 mssl.

The T-088/T-086 reservoirs was encountered 30-40 meters below the primary reservoir. The reservoir consists of two distinct sand bodies in the -1 and Gendalo-4 wells that share the same gas and water gradient based on MDT pressure data.

The up-dip -1 well found a GWC @ -2,556 meter while the down-dip Gendalo-4 was found wet. GWC at -1 well position was confirmed by the -1 and Gendalo-4 pressure gradient analysis. T088-T086 seems to be a more channelized systems with two main fairways oriented NW-S and NW-SE. In the SE area probably, there are some features that could be related to bottom currents reworking or crevasse splays.

The T-084 is the basal sand in the Pliocene slope valley depositional system. RMS amplitude extraction suggests a possible channels systems in -1 area and a stratigraphic expansion with depositional lobes in the area south of Gendalo-4. T-084 was found gas bearing in -1 well, while Gendalo-4 didn't reach this target.

-1 well encountered a GWC at -2,626 m TVDSS which is confirmed by MDT pressure points. -1 MDT pressure analysis shows that the T-084 is over-pressured relative to the shallower reservoirs.

Based on the petrophysical evaluation of the explorative wells done in 2020, as part of the Integrated Reservoir Study, -1 and Gendalo-4 penetrated the T90, T088-T086 and T084 encountering the thickness and founding petrophysical properties as indicated in table below.

Wells	Reservoir	Gross Interval m TVD	Net Reservoir m TVD	NTG Reservoir	Avg. PHIE Reservoir	Avg. Swe Pay	Avg. Perm. Reservoir
-1	T90	23	21	0.9	0.25	0.42	76 mD
Gendalo-4		54	43	0.8	0.26	0.45	129 mD
-1	T88/86	72	34	0.46	0.24	0.48	109 mD
Gendalo-4		55	24	0.43	0.25	-	177 mD
-1	T84	21	20	0.94	0.30	0.16	288 mD
Gendalo-4		Not Penetrated					

Table 6 – Summary of the average properties of reservoirs, based on the explorative wells.

A 3D model was built to capture all the correctly scaled reservoir characteristics that have been identified from seismic, well, and analog data, and delivers an original gas-in-place. The volumetric field average properties are reported in the table below.

Case	Avg NTG [%]	Avg Porosity [%]	Avg SW [%]
Reference Case	67%	27%	39%
T090	75%	27%	41%
T088-086	43%	25%	44%
T084	83%	33%	20%

Table 7 – Average reservoir properties from volumetrics

PVT experiments are not available in field. In order to characterize the reservoir fluid, gas composition and CGR from MDT sampling have been considered. The reference sample, taken in T090 level at a depth of 8158 ft (2486.6 m), pressure of 3903 Psia and a temperature of 151 °F, has a C1 content of 98.3%, a gas gravity of 0.58 and a CGR of 5.8 Stb/MMscf. The data have matched by means of an equation of state in PVTi software. The T90 PVT has been considered for the other levels of the field.

Properties	Value
Reservoir Pressure (bara)	270-272
Reservoir Temperature (°C)	73-74

Table 8 – Reservoir Fluid Conditions and Properties

-2 well was recently drilled (May 2021) and preliminary petrophysical analysis confirms the good reservoir quality of the primary target (T-090), on which the development of the field is based. PVT and core analysis results are not yet available at the time of the present BoD.

7.2 Reservoir Fluid Composition

The reservoir pressure, temperature and fluid properties for reservoir are reported at para.7.1, while its compositions is tabulated as follows .

Component	%mol	MW	Specific Gravity	Critical Temp. °C	Critical Pressure bara	Acentric factor	boiling Temp. °C	Critical vol. cm3/mol
N2	0.040	28.01		-147.0	33.9	0.0400	-195.8	89.8
CO2	0.919	44.01		31.1	73.8	0.2250	-78.5	94.0
C1	98.200	16.04		-82.6	46.0	0.0080	-161.6	99.0
C2	0.200	30.07		32.3	48.8	0.0980	-88.6	148.0
C3	0.090	44.10		96.7	42.5	0.1520	-42.5	203.0
i C4	0.020	58.12		135.0	36.5	0.1760	-11.8	263.0
nC4	0.020	58.12		152.1	38.0	0.1930	0.5	255.0
i C5	0.010	72.15		187.3	33.8	0.2270	27.9	306.0
nC5	0.010	72.15		196.5	33.7	0.2510	36.1	304.0
C6	0.011	86.18	0.664	234.3	29.7	0.2960	68.8	370.0
C7	0.097	96.00	0.702	260.7	28.7	0.3371	92.0	521.9
C8	0.079	107.00	0.730	282.3	26.8	0.3740	116.8	532.0
C9	0.065	121.00	0.754	306.9	24.6	0.4202	142.3	561.5
C10	0.052	134.00	0.776	328.2	23.5	0.4627	165.9	592.4
C11	0.041	147.00	0.795	348.0	21.8	0.5007	187.3	628.0
C12	0.031	161.00	0.813	368.1	20.6	0.5428	208.4	672.2
C13	0.023	175.00	0.829	387.1	19.7	0.5837	227.3	719.9

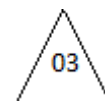
Table 9 – Reservoir Fluid Composition

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7.3 Production Capacity Overview and Profiles

Two reference Production profiles are reported below:

- Constrained case (max trunkline flowrate 230 MMSCFD)



Year	Month	Well Gas Rate (MMSCFD)		Well Cond Rate (STBD)		Well Water Rate (STBD)	
		-3	-4	-3	-4	-3	-4
2026	Jan	0	0	0,0	0,0	0,0	0,0
	Feb	0	0	0,0	0,0	0,0	0,0
	Mar	0	0	0,0	0,0	0,0	0,0
	Apr	0	0	0,0	0,0	0,0	0,0
	May	0	0	0,0	0,0	0,0	0,0
	Jun	0	0	0,0	0,0	0,0	0,0
	Jul	0	0	0,0	0,0	0,0	0,0
	Aug	4	4	0,0	0,0	0,0	0,0
	Sep	100	100	0,0	0,0	0,0	0,0
	Oct	107	107	0,0	0,0	0,0	0,1
	Nov	110	111	0,0	0,0	0,0	0,1
	Dec	115	116	0,0	0,0	0,0	0,1
2027	Jan	115	116	0,0	0,0	0,0	0,1
	Feb	116	116	0,0	0,0	0,0	0,1
	Mar	115	115	0,0	0,0	0,0	0,2
	Apr	114	114	0,0	0,0	0,0	0,2
	May	113	112	0,0	0,0	0,0	0,2
	Jun	112	111	0,0	0,0	0,0	0,2
	Jul	111	110	0,0	0,0	0,0	0,2
	Aug	110	108	0,0	0,0	0,1	0,2
	Sep	109	107	0,0	0,0	0,1	0,2
	Oct	108	106	0,0	0,0	0,1	0,2
	Nov	107	105	0,0	0,0	0,1	0,2
	Dec	106	103	0,0	0,0	0,1	0,2
2028	Jan	105	102	0,0	0,0	0,1	0,2
	Feb	104	101	0,0	0,0	0,1	0,2
	Mar	103	100	0,0	0,0	0,1	0,2
	Apr	100	97	0,0	0,0	0,1	0,2
	May	100	97	0,0	0,0	0,1	0,2
	Jun	99	96	0,0	0,0	0,1	0,3
	Jul	98	95	0,0	0,0	0,1	0,3
	Aug	97	94	0,0	0,0	0,1	0,3

	Sep	96	93	0,0	0,0	0,1	0,3
	Oct	94	91	0,0	0,0	0,1	0,3
	Nov	93	90	0,0	0,0	0,1	0,3
	Dec	92	89	0,0	0,0	0,1	0,3
2029	Jan	92	88	0,0	0,0	0,1	0,3
	Feb	91	87	0,0	0,0	0,1	0,3
	Mar	90	86	0,0	0,0	0,1	0,3
	Apr	89	85	0,0	0,0	0,1	0,3
	May	88	84	0,0	0,0	0,1	0,3
	Jun	88	83	0,0	0,0	0,1	0,3
	Jul	86	81	0,0	0,0	0,1	0,3
	Aug	86	81	0,0	0,0	0,1	0,3
	Sep	85	80	0,0	0,0	0,1	0,3
	Oct	84	79	0,0	0,0	0,1	0,3
	Nov	84	79	0,0	0,0	0,1	0,3
	Dec	85	79	0,0	0,0	0,1	0,3
2030	Jan	85	79	0,0	0,0	0,1	0,3
	Feb	85	79	0,0	0,0	0,1	0,3
	Mar	84	78	0,0	0,0	0,1	0,3
	Apr	83	77	0,0	0,0	0,1	0,3
	May	82	76	0,0	0,0	0,1	0,3
	Jun	80	75	0,0	0,0	0,1	0,3
	Jul	79	74	0,0	0,0	0,1	0,3
	Aug	78	72	0,0	0,0	0,1	0,3
	Sep	77	71	0,0	0,0	0,1	0,3
	Oct	76	70	0,0	0,0	0,1	0,3
	Nov	75	69	0,0	0,0	0,1	0,3
	Dec	74	68	0,0	0,0	0,1	0,3
2031	Jan	73	66	0,0	0,0	0,1	0,3
	Feb	72	65	0,0	0,0	0,1	0,3
	Mar	71	64	0,0	0,0	0,1	0,3
	Apr	70	63	0,0	0,0	0,1	0,3
	May	69	62	0,0	0,0	0,1	0,3
	Jun	68	61	0,0	0,0	0,1	0,3
	Jul	67	60	0,0	0,0	0,1	0,3
	Aug	67	59	0,0	0,0	0,1	0,3
	Sep	66	58	0,0	0,0	0,1	0,3
	Oct	65	57	0,0	0,0	0,1	0,3
	Nov	64	56	0,0	0,0	0,1	0,3
	Dec	63	55	0,0	0,0	0,1	0,3

Table 10 – Production Profile data (Constrained Case)

- Unconstrained case (max trunkline flowrate 270 MMSCFD)

Year	Month	Well Gas Rate (MMSCFD)		Well Cond Rate (STBD)		Well Water Rate (STBD)	
		-3	-4	-3	-4	-3	-4
2026	Jan	0	0	0,0	0,0	0,0	0,0
	Feb	0	0	0,0	0,0	0,0	0,0
	Mar	0	0	0,0	0,0	0,0	0,0
	Apr	0	0	0,0	0,0	0,0	0,0
	May	0	0	0,0	0,0	0,0	0,0
	Jun	0	0	0,0	0,0	0,0	0,0
	Jul	0	0	0,0	0,0	0,0	0,0
	Aug	6	6	0,0	0,0	0,0	0,0
	Sep	108	108	0,0	0,0	0,0	0,0
	Oct	107	107	0,0	0,0	0,0	0,1
	Nov	110	111	0,0	0,0	0,0	0,1
	Dec	115	116	0,0	0,0	0,0	0,1
2027	Jan	119	120	0,0	0,0	0,0	0,1
	Feb	122	122	0,0	0,0	0,0	0,2
	Mar	125	125	0,0	0,0	0,0	0,2
	Apr	129	128	0,0	0,0	0,0	0,2
	May	133	132	0,0	0,0	0,1	0,2
	Jun	131	130	0,0	0,0	0,1	0,3
	Jul	129	127	0,0	0,0	0,1	0,3
	Aug	126	124	0,0	0,0	0,1	0,3
	Sep	124	122	0,0	0,0	0,1	0,3
	Oct	122	120	0,0	0,0	0,1	0,3
	Nov	120	117	0,0	0,0	0,1	0,3
	Dec	118	115	0,0	0,0	0,1	0,3
2028	Jan	116	113	0,0	0,0	0,1	0,3
	Feb	114	111	0,0	0,0	0,1	0,3
	Mar	112	109	0,0	0,0	0,1	0,3
	Apr	111	107	0,0	0,0	0,1	0,3
	May	109	106	0,0	0,0	0,1	0,3
	Jun	107	104	0,0	0,0	0,1	0,3
	Jul	106	102	0,0	0,0	0,1	0,3
	Aug	104	100	0,0	0,0	0,1	0,3
	Sep	103	99	0,0	0,0	0,1	0,3
	Oct	101	97	0,0	0,0	0,1	0,3
	Nov	100	95	0,0	0,0	0,1	0,3
	Dec	98	94	0,0	0,0	0,1	0,3

2029	Jan	97	92	0,0	0,0	0,1	0,3
	Feb	96	91	0,0	0,0	0,1	0,3
	Mar	96	91	0,0	0,0	0,1	0,3
	Apr	94	90	0,0	0,0	0,1	0,3
	May	93	88	0,0	0,0	0,1	0,3
	Jun	92	87	0,0	0,0	0,1	0,3
	Jul	90	85	0,0	0,0	0,1	0,3
	Aug	89	84	0,0	0,0	0,1	0,3
	Sep	88	83	0,0	0,0	0,1	0,3
	Oct	87	82	0,0	0,0	0,1	0,3
	Nov	86	81	0,0	0,0	0,1	0,3
	Dec	84	80	0,0	0,0	0,1	0,3
2030	Jan	83	79	0,0	0,0	0,1	0,3
	Feb	82	77	0,0	0,0	0,1	0,3
	Mar	81	76	0,0	0,0	0,1	0,3
	Apr	80	75	0,0	0,0	0,1	0,3
	May	79	74	0,0	0,0	0,1	0,3
	Jun	78	73	0,0	0,0	0,1	0,3
	Jul	77	72	0,0	0,0	0,1	0,3
	Aug	76	70	0,0	0,0	0,1	0,3
	Sep	75	69	0,0	0,0	0,1	0,3
	Oct	74	68	0,0	0,0	0,1	0,3
	Nov	73	67	0,0	0,0	0,1	0,3
	Dec	72	66	0,0	0,0	0,1	0,3
2031	Jan	71	65	0,0	0,0	0,1	0,3
	Feb	70	64	0,0	0,0	0,1	0,3
	Mar	69	63	0,0	0,0	0,1	0,3
	Apr	69	62	0,0	0,0	0,1	0,3
	May	68	61	0,0	0,0	0,1	0,3
	Jun	67	60	0,0	0,0	0,1	0,3
	Jul	66	59	0,0	0,0	0,1	0,3
	Aug	65	58	0,0	0,0	0,1	0,3
	Sep	65	58	0,0	0,0	0,1	0,3
	Oct	64	57	0,0	0,0	0,1	0,3
	Nov	63	56	0,0	0,0	0,1	0,3
	Dec	62	55	0,0	0,0	0,1	0,3
	Dec	0	0	0,0	0,0	0,0	0,0

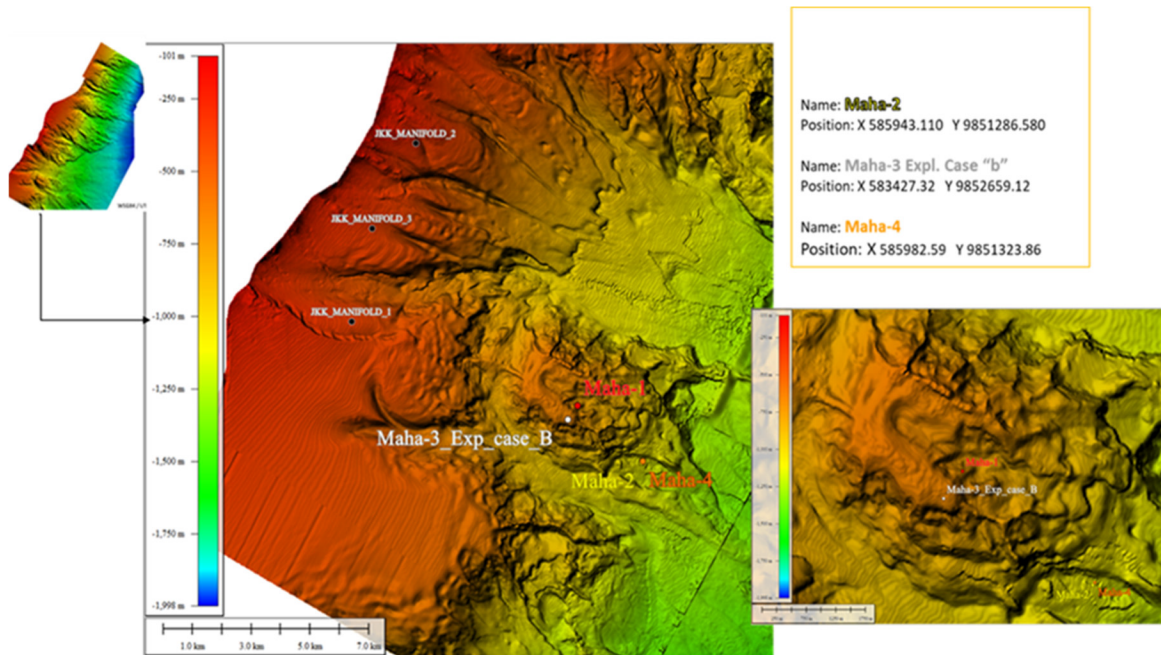
Table 11 – Production Profile data (Unconstrained Case)

8 DRILLING & COMPLETIONS

8.1 Drilling and Completions overview

development considers the drilling of two wells:

- -3
- -4



8.2 Wells targets coordinates

The following table resumes the preliminary Wellheads coordinates as per [18].

➤ **PROJECT-3**

Water depth	RKB elevation	Sea Bed (from RKB)
(m)	(m)	(m)
811	25	836

Well Head coordinates (Indonesia Offshore – PROJECT-3 Expl. Case "b")	
Northing (m) South:	9,852,056
Easting (m) East:	583,427
Latitude (y):	1° 20' 18.163" S
Longitude (x):	117° 44' 59.719" E
Geodetic System:	Universal Transverse Mercator
Geodetic Datum:	WGS 1984
MAP Zone:	Zone 50 S (114 E to 120 E)

➤ **PROJECT-4**

Water depth	RKB elevation	Sea Bed (from RKB)
(m)	(m)	(m)
1103	29	1128

Well Head coordinates (Indonesia Offshore - -4)	
Northing (m) South:	9,851,286
Easting (m) East:	585,820
Latitude (y):	1° 20' 43.223" S
Longitude (x):	117° 46' 17.159" E
Geodetic System:	Universal Transverse Mercator
Geodetic Datum:	WGS 1984
MAP Zone:	Zone 50 S (114 E to 120 E)

8.3 Preliminary Casing Design

A preliminary material selection, considering that a pore pressure study is not still available, we can chose like casing / liner string the same material and size already used for Merakes & Jangkrik projects and to consider what has been already "planned / mentioned" within Gas Brand IDD (Indonesia Deepwater Development) Project, POD June 2018.

CASING SETTING DEPTH "PROJECT-3" (proposed).								
Size (Inches)	Steel grade (//)	Wall thikness (Inches)	Weight (Lb/ft)	Connection type (//)	Csg shoe depth (TVDss) (m)	Csg shoe depth (TVD) (m)	Csg shoe depth (MD) (m)	Csg / Liner Lenght (MD) (m)
36	X52	1,5	552,7	Quick Connector	881	906	906	70
20	X56	0,812	166,4	Quick Connector	1461	1486	1486	650
13,625	P110	0,625	88,2	Premium	2075	2100	2171	1335
10,75	T95/P110	0.595	65.7	Premium	2674	2699	3178	1127

10-3/4 Liner	TOL (TVDss): 1989m	TOL (TVD): 2014m	TOL (MD): 2051m	Total liner length: 1127m MD	Liner Overlap: 120m MD
-------------------------	-----------------------	---------------------	--------------------	---------------------------------	---------------------------

-3 Csg /Lnr setting depth & Type

CASING SETTING DEPTH "PROJECT-4" (proposed).								
Size (Inches)	Steel grade (//)	Wall thickness (Inches)	Weight (Lb/ft)	Connectio n type (//)	Csg shoe depth (TVDss) (m)	Csg shoe depth (TVD) (m)	Csg shoe depth (MD) (m)	Casing / Liner Lenght (MD) (m)
36	X52	1,5	552,7	Quick Connector	1173.48	1198	1198	70
20	X56	0,812	166,4	Quick Connector	1703.48	1728	1728	600
13,625	P110	0,625	88,2	Premium	2225	2250	2272	1144
10,75	T95/P110	0.595	53,5	Premium	2844	2869	3302	1150
7	P110	0,453	32	Premium	3353	3378	4205	1023

Note: The contingency of 7" Liner will be set only to cover exploration tail incase needed.

10-3/4 Liner	TOL (TVDss): 2120m	TOL (TVD): 2145m	TOL (MD): 2152m	Total liner length: 1150m MD	Liner Overlap: 120m MD
-------------------------	-----------------------	---------------------	--------------------	---------------------------------	---------------------------

7 Liner	TOL (TVDss): 2777m	TOL (TVD): 2802m	TOL (MD): 3182m	Total liner length: 1023m MD	Liner Overlap: 120m MD
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-4 Csg /Lnr setting depth & Type

Based on experience, no H₂S is not present in the field.

Fluid sampling was obtained using the MDT tool in both the Gendalo-4 and -1 wellbores. All samples obtained using the MDT tool were contaminated with synthetic oil-based drilling fluids, resulting in questionable measurements of condensate yield. Since there are no specific lab analysis reports of the MDT samples collected for the secondary reservoirs in (3140/50 & 3170), the 3130 fluid properties can be assumed for the secondary reservoirs. The properties from sample # JFL2002074 are shown in table below. In order to estimate condensate yield, the observed MDT pressure gradient in the 3140/50 was matched using a fluid density calculation. The technique was found not to be sensitive to condensate gravity and results in condensate yield estimation of 2 bbl / mmcf.

Element		Mol percent
Nitrogen	N ₂	0.04
Carbon dioxide	CO ₂	0.92
Hydrogen Sulfide	H ₂ S	0.00
Methane	C ₁	98.36
Ethane	C ₂	0.20
Propane	C ₃	0.00
Iso-Butanes	iC ₄	0.02
n-Butanes	nC ₄	0.02
Iso-Pentanes	iC ₅	0.01
n-Pentanes	nC ₅	0.01
Hexanes	C ₆	0.00
Heptanes Plus	C ₇₊	0.33 SOBM Contamination
Molecular Weight		17.00
Gas Gravity		0.580
Plus Fraction Properties		
Molecular Weight of Heptanes Plus		142 Estimated
Density of Heptanes Plus, g/cc		0.827 Estimated
Properties of Produced Wellstreams		
Calculated gas viscosity, cP		0.021
Gas Deviation Factor (Z)		0.918
C ₅₊ Yield, bbl/MMscf		2.0 Estimated
Condensate API Gravity		50 Estimated

On -1 fluid samples indicate the need for corrosion resistant alloys in the flow-wetted tubulars. Main contributor on corrosion potential on field was CO₂ in formation. High partial pressure value shows the requirement of corrosive resistance material on flow wetted including 9 5/8" production liner and 5 1/2" production tubing. The use of 13 Cr (or Super 13 Cr) martensitic stainless steel could be a solution to prevent the corrosion phenomenon. For the casing above packer carbon or low alloy steel material is a suitable. It can be selected among sour service materials, according to mechanical strength required for the casing application according to API 5CT.

8.4 Completion Schematics

The design has been prepared in compliance with "Completion Design Procedure" (STAP-P- 1-M-26543).

The following considerations have been taken into account in the current completion design:

- Respect of HSE regulations.
- Capability to deliver forecasted hydrocarbon production rates.
- Capability to inject adequate water and gas rates.
- Safety of operations and reliability of equipment.
- Longevity for the full wells lifetime.
- Operational time optimization due to high daily rig cost.
- Simplicity of design with standard and field proven technology.
- Equipment cost and delivery time reduction achieved by standardization.
- Capability to cope with the worst anticipated operating loads and environment.
- In compliance with International Standards and good oilfield practices.

Three well completion typologies will be evaluated:

- 1) 3 (scenario 4) well would be completed in two production zones with CHFP in 10 3/4" liner and smart upper completion.
- 2) 4 well would be completed with 1 CHFP inside 10 3/4" liner with possibility to split into 2 stack. Upper smart completion will be also available incase required.

Current completion strategy designed to maximize well deliverability by upsize the completion size to allow higher gas rate in 10-3/4" liner system compared with 9-5/8" liner system.

Other options can be further evaluated at later stage of the project.

8.5 Preliminary Metallurgy and Elastomers Selection

No dedicated completion material study has been commissioned yet. However 13Cr material will be considered as most likely for the analogy with other Indonesian project already developed (Jangkrik, Merakes). This consideration will be applied also for cost evaluation. This aspect will be further analyzed in the following step of the project.

9 FLUID DATA AND PRODUCTION CHEMISTRY

9.1 Reservoir Fluid Properties

Due to expected high pressure and relatively low temperature during both normal and transient operations, fluids are expected to be susceptible to hydrate formation.

Hydrates formation shall be avoided in all scenarios by means of continuous hydrates inhibitor injection (Lean MEG solution MEG 80%wt). Similar hydrate prevention strategy as for JKK and Merakes field is considered.

MeOH is injected in start-up / restart due to avoid low temperature issues and hydrate formation risks.

No asphaltenes, foaming and emulsion formations are assumed present in the reservoir fluids. Scale formation is assumed present as for JKK and Merakes reservoir fluids.

9.2 Reservoir Fluid Composition

For the reservoir fluid composition, ref. to 7.2.

9.3 Scale Potential

Scale formation is assumed present as for JKK and Merakes reservoir fluids.

9.4 Wax Formation and Rheology

See 9.1, no waxes, foaming and emulsion formations are expected in the reservoir fluid.

9.5 Hydrate Equilibrium Curves

Hydrates curve have been calculated with the reservoir fluid composition reported in section 7.2 saturated at reservoir conditions (30 bar, 74°C).

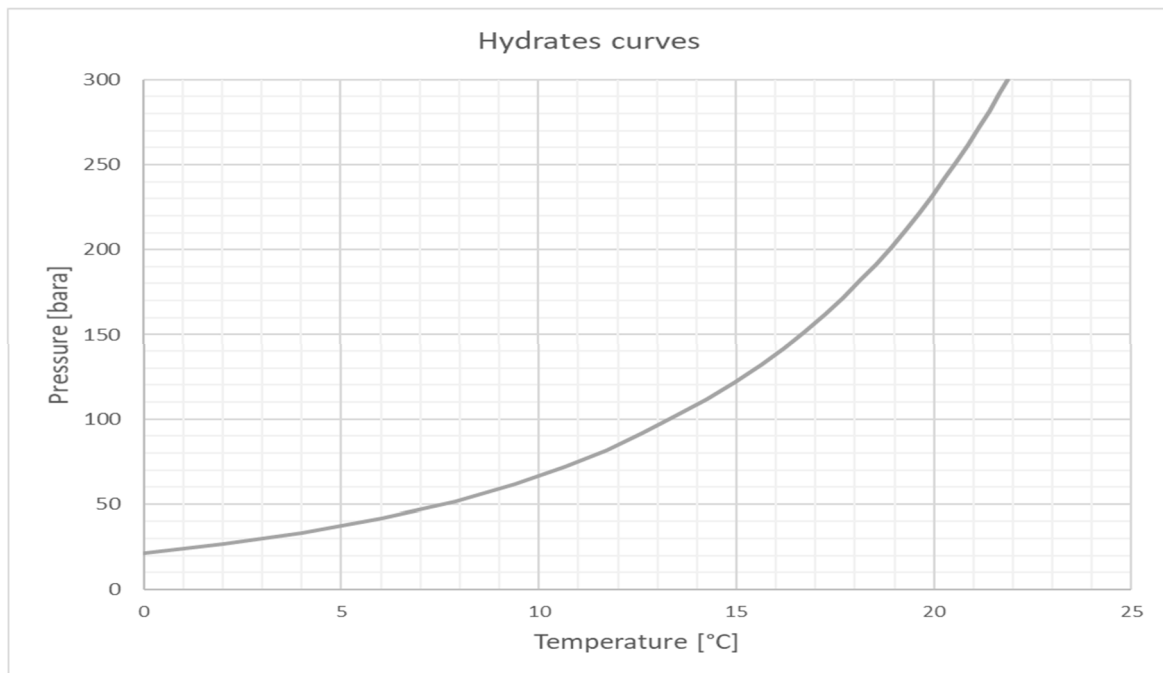


Figure 5: - Hydrate formation curves

9.6 Hydrogen Sulphide

The reservoir fluid is expected to be H₂S free.

9.7 Asphaltenes

No asphaltenes are expected in the reservoir fluid.

9.8 Material Selection

As no data are available on water analysis, the same chemical composition as for JKNE will be considered with as main constituent used for material selection carbonate with a content equal to 105 meq/l.

9.8.1 CO₂ Corrosion

Wet CO₂ corrosion is generally referred as 'sweet corrosion' when H₂S is absent. When CO₂ is present in the gas phase, any water in contact with this gas will dissolve CO₂ to a concentration proportional to the partial pressure pCO₂, of the CO₂ in the gas and temperature. The overall philosophy used in the selection of materials and corrosion control systems is based on conditions of operation with adequate integrity while minimizing capital costs and maintaining schedule for fabrication.

Corrosion shall be mitigated by sufficient application or combination of the following methods:

- Materials selection (corrosion allowance)
- Coatings
- Chemical treatment
- Cathodic protection
- Corrosion control/monitoring

The corrosion allowances for pipelines shall be specified with regard to the corrosion rates calculated after taking into account the effectiveness of inhibition, environmental conditioning and design life. Generally, process and corrosive utilities equipment and piping shall be specified with a minimum 3.0 mm corrosion allowance and maximum of 6.0 mm corrosion allowance while pipeline can be maximum 8 or 10 mm.

Calculated uninhibited corrosion rate is 0.9 mm/yr equivalent with 8.84 mm reduction thickness during 20 years design lifetime. By injecting corrosion inhibitor as per document Internal Corrosion - Fluids Classification and Corrosion Parameters Definition Ref. Doc. 02555.VAR.COR.PRG which may be assumed that inhibition can decrease the corrosion rate to 0.1 mm/year

Efficiency inhibitor will use formula as per standard.

$$C_{\text{Corr}} = (C_{\text{Rinhib}} \times \text{lifetime} \times \text{availability}) + C_{\text{Runhib}} \times \text{lifetime} \times \text{un-availability} \\ = (0.1 \times 25 \times 0.9) + (C_{\text{Runhib}} \times 25 \times 0.1)$$

Infield Pipeline, Formation Water Case

Description	Value	Unit
max. corrosion rate	2.0	mm/y
Inhibited corrosion rate	0.2	mm/y
total corrosion allowance with 95% CI availability (15 years)	4.35	mm

The result of evaluation for considered only water condensed can be summarized as below.

Infield Pipeline, Condensed Water Case

Description	Value	Unit
max. corrosion rate	2.8	mm/y
Inhibited corrosion rate	0.2	mm/y
total corrosion allowance with 95% CI availability (15 years)s	4.95	mm

Based on the all above cases, material selection for flowline is calculated as CS + 5 mm CA + >95% of corrosion inhibitor availability.

9.9 Flow Assurance Issues

For Flow Assurance details please see ref. 9.1.

9.10 Flowing And Shut In Condition

9.10.1 Flowing Well Head Pressure

The flowing well head pressure of considered for the analyses are reported below. Grey cells highlight that the wells or cluster is closed.



Expected Mode	Date	PROJECT	
		PROJECT-4	PROJECT-3
HP mode	Sep-26	206	196
	May-27	152	134
	Jun-28	125	110
	Dec-29	97	85
	Jun-30	90	80
LP mode	Jun-31	78	66
	Jun-32	68	57
	Jun-33	61	51
	Jun-34	56	46
	Jun-35	47	48
	Dec-36	38	40
	Jan-37		46

Table 12 – Unconstrained case - FTHP

9.10.2 Flowing Well Head Temperature

The flowing well head temperature of wells considered for the analyses are reported below. The two tables report the flowing temperature upstream and downstream PCVs:

Flowing Wellhead Temperature Upstream PCV		
Date	-4	-3
Sep-26	59.0	60.0
May-27	55.0	55.0
Jun-28	54.0	54.0
Dec-29	54.0	54.0
Jun-30	54.0	54.0
Jun-31	54.0	53.0
Jun-32	54.0	54.0
Jun-33	54.0	54.0
Jun-34	53.0	54.0
Jun-35	42.0	54.0
Dec-36	4.0	53.0
Jan-37	4.0	47.0

Table 13 – Unconstrained Case – FTHT u/s PCV

Flowing Wellhead Temperature Downstream PCV		
Date	-4	-3
Sep-26	41	41
May-27	50	52
Jun-28	51	52
Dec-29	53	54
Jun-30	54	54
Jun-31	52	53
Jun-32	53	53
Jun-33	53	54
Jun-34	53	53
Jun-35	42	53
Dec-36	4	53
Jan-37	4	46

Table 14 - Unconstrained Case – FTHT d/s PCV

9.10.3 Topside Arrival Pressure/Temperature

As per base case, is kept in production in Hybrid mode (HP or LP) as detailed in the previous chapters. The fluid temperature at FPU arrival is expected in the range -2-to-10°C, the lorelated to high flowrate.

9.10.3.1 Operating Cases

Base Case - with single flowline connection (Figure 6): the n.2 new wells are tied- back to Jangkrik trunkline 1 by means of 12" new subsea production flowline. Jangkrik Production from Cluster 1 will be sent to Jangkrik Cluster 3.

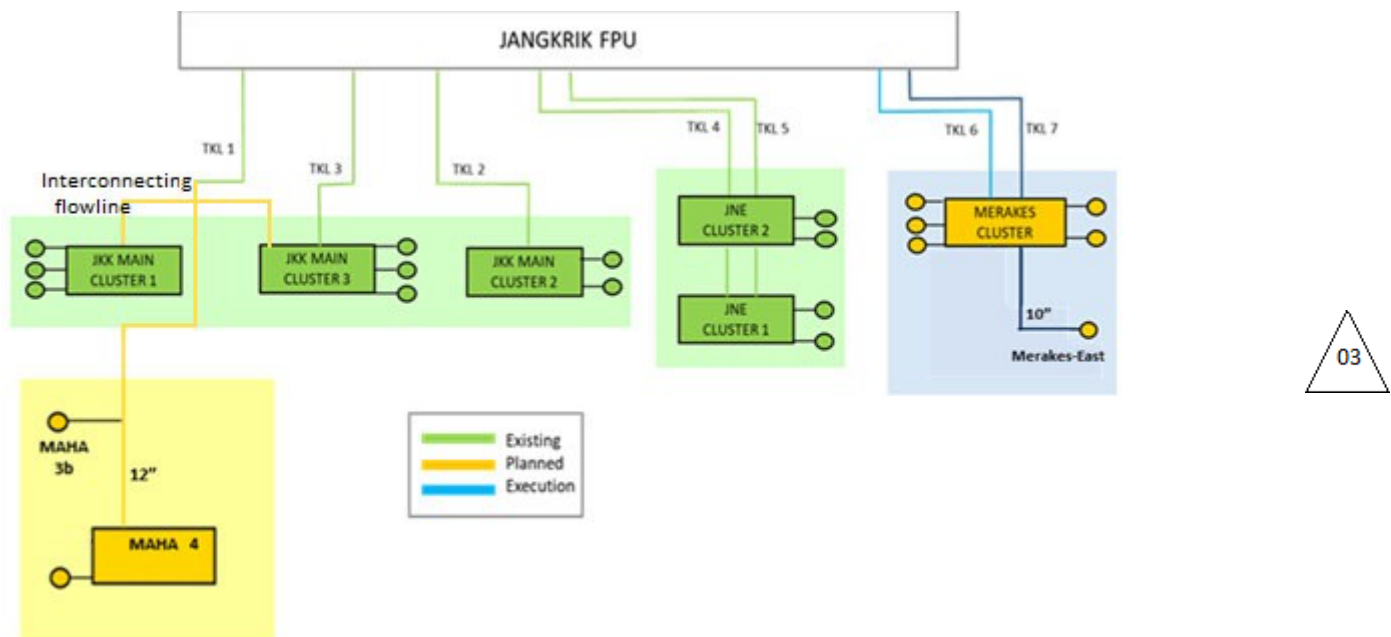


Figure 6 – Field Development

9.10.3.2 Inlet Flowrate FPU JKK

The following production cases are selected for design purposes (Table 15) and with the aim to verify the existing FPU capacities.

Field	TKLs	Flowrate (MMSCFD)	Inlet Pressure (barg)	Slug Catcher
Jangkrik	TKL1	223.6	40	Jangrjik North East
		0	40	
Jangkrik	TKL2	11.6	25	Jangkrik Main
	TKL3	45.3	25	
Jangkrik NorthEast	TKL4	9.71	25	
	TKL5	9.71	25	Merakes/Merakes East
	TKL6	190	25	
	TKL7	190	25	Merakes East 87.5 MMSCFD Merakes 292.6 MMSCFD -

Table 15: STRATEGIC PLAN (MKSE SU 1-Jul-25, PROJECT SU 1-Mar-25) with 2.8%DT

	JKK/JNE	MKS	PROJECT	MKSE
Flowrate [MMSCFD]	76.37	292.6	223.6	87.5

Slug Catchers Capacity:

	HP Mode	LP Mode
	MMSCFD	MMSCFD
JKK Main SC	463	342
JKK NE SC	309	228
Merakes SC	450	400

For fields the flowrates for gas, condensate and total free water @Jangkrik FPU inlet have been extracted from the production profiles received by HQ, where the gas, condensate and water flowrates used in the "Strategic Case" (i.e. the Dual Mode Case) with a maximum export capacity of about 750 MMSCFD @FPU inlet and with producing 230 MMSCFD as the maximum plateau in HP mode and 170MMSCFD plateau in LP mode, which Low pressure with an arrival pressure of 25 barg and High Pressure with an arrival pressure of 40 barg on FPU inlet. In the following Table 16, shown the gas flowrate in the various trunkline of JKK FPU from different case study and debottlenecking projects.

CASES		PRODUCTION PROFILES									
		JKK/JNE	MKS	Maha	MKSE	Gas Rates per TKL (MMSCFD)					Total
						CL-1	CL-2	CL-3	CL-JNE	CL-MKS	
Case 1	LP	320	400	-	-	107	38	85	90	400	720
						LP	LP	LP	LP	LP	
Case 2	Hybrid	155	269	195	131	230	20	50	50	400	750
						HP	LP	LP	LP	LP	
Case 3	LP	66	128	148	65	170	-	22	22	193	407
						LP	LP	LP	LP	LP	
Case 4	Hybrid	310	426	-	-	100	45	79	86	426	736
						LP	LP	LP	LP	HP	

Table 16: Design cases from debottlenecking projects

HP = 40 barg at FPU inlet

LP = 25 barg @ FPU Inlet

- Case 1: adjusted based on received profiles, January 2024 (total production 616 MMSCFD)
- Case 2: smoothly adjusted based on received profiles, July 2025 (total production 746 MMSCFD)
- Case 3: as per received profiles, February 2028. Requested only verification of inlet facilities (TKL-1 and Slug Catcher)
- Case 4: as per received profiles, March 2023. It should be covered by Case 2.

9.10.3.3 Target LP Max Flowrate

- ☐ 616 MMSCFD max flow in LP based on production profile
- ☐ Maximum production with minor modifications
 - 600 MMSCFD @ LP
 - Based on max seawater flowrate of 7500 m3/h
- ☐ 720 MMSCFD Target FPU capacity in LP for DBN Verification
 - According to previous study, the same modifications are required above 600 MMSCFD in LP up to 720 MMSCFD

Seawater consumption (from Saipem study): ~ 8400 m³/h

9.11 Product Specification

9.11.1 Produced Oil Specification

is connected to existing Jangkrik FPU and then the same specification on gas and condensates of Jangkrik project applies.

So following specifications for Gas and Condensate are assumed to be valid also for , based on Process Basis of Design for Jangkrik FPU.

Properties	Specs
HC Dew Point	12°C @ any pressure from 52 barg up to maximum export pressure;
Water Dew Point	9°C @ maximum export pressure
Associated water content	9 lb/MMSCF

Table 17: Produced Specifications

Properties	Specs
RVP	≤ 11 psia
TVP @ 40°C	≤ 13 psia
Water Content	< 0.1% vol.
BSW	< 10 PTB

Table 18: Sale Condensate Specifications

9.11.2 Produced Treated Water

The FPU is designed to handle, treat and dispose the produced water and any other waste water generated by the process and utility units aboard the FPU. A dedicated Produced Water Treatment unit of about 1150 Sbbbl/d is available.

Treated water discharged overboard shall meet the following specifications:

- Maximum HC content: 15 ppmv (30 days average), 42 ppmv maximum daily peak
- Maximum MEG content: 3500 ppmv
- Maximum discharge temperature: 40°C

Discharged water shall be continuously metered and its quality continuously monitored in line with local environmental regulations.

On-line analysis shall be based on Indonesian national standard SNI 06-6989.10-2004. In the event that the water quality requirements are not met, produced water shall be automatically routed to the slop oil tank.

A dedicated hull storage of 1300 m³ is provided for Treated Water.

9.11.3 H₂S Content

The reservoir fluid is expected to be H₂S free.

9.11.4 CO2 Content

The reservoir fluid from , as evident from the reservoir fluid compositions in Table 9, shows a CO2 content of 0.92 mol %.

9.12 Field Flowrates for Design Purpose

The following production cases are selected for design purposes (Table 19) and with the aim to verify the existing FPU capacities

Fluid	HP
Inlet Gas [MMSCFD]	223.6
Inlet Condensate [Sbbl/d]	1303.5
Inlet Water [Sbbl/d]	0.68

Table 19 - Development - Design cases

For field the flowrates for gas, condensate and total free water @Jangkrik FPU inlet have been extracted from the production profiles received by Reservoir HQ.

The saturation water and MEG associated to Jangkrik has been prorated according to the new gas flowrates taking into by assuming the same corresponding pro-rating values used for Jangkrik Main.

10 FACILITIES

10.1 Subsea, Umbilical and Flowlines

In the following, a description of the subsea system (incl. umbilical and subsea structures) and flexible flowline system foreseen for the field is provided.

10.1.1 FPU

For a FPU Process Description, refer to [22].

10.1.2 Design Life

The design life of the subsea production and control system shall be 20 years.

10.1.3 Maximum Water Depth

The whole subsea system shall be designed for 1.200m of water depth.

10.1.4 Main Subsea Equipment

A preliminary subsea equipment list and related design data is provided in the below tables.

Item	Quantity	Design Pressure	Design Temperature
Production Xmas Tree	2	10.000 psi	Upstream the choke: -18/+121 °C (1) Downstream the choke (included): -48/+121 °C
HIPPS System	1	(i) 270 Bar Header from HBV1 (valve not included) to inboard connector, Header from TIV1 (valve not included) to inboard connector & adjoining Hot Stab lines; (ii) 421 Bar remaining parts of Header, header valves and chemical injection lines	-20/+70°C

		& test port lines.	
TEE Structure	1	270 bar for header, 650 for branch up to branch valve (valve included)	-20/+70°C
Subsea Structure 4 Hub	1	520 bar for all parts of the structure exception made for the header connectors (270 bar)	-29/+70°C
UTA	1-off – Project UMB1 UTA A 1-off – Project UMB1 UTA B 1-off – Project UMB2 UTA A 1-off – Project UMB2 UTA B		
FLET	1	TBD	TBD



Table 20: Preliminary list of main subsea equipment

(1) As per Merakes XTR

(2) MEG pump design pressure = 340 barg (PSV set point). Including Pressure head at 1200m is therefore equal to 340 barg + 130bar = 470 bar. See Ref. [32] for Design pressure definition due to MEG packing condition.

(3) $3\&2\&4\text{WHSIP} \times 1.1 = 242.2 \times 1.1 = 270\text{bar}$

(4) DT=Max operating (55Deg) plus 15Deg of contingency

(5) A new FLET is foreseen for connecting the Jangkrik Cluster 1 to Jangkrik Cluster 3 already existing FLET 1, through a new Interconnecting Line

HIPPS valve set point max flowing plus contingency = 110bar

Note: As contingency approach, the DP of 7500psi is considering potential closure of Subsea Structure valve by mistake during installation of operation phase. As consequence, the DP of Subsea Structure and welljumper is driven by MEG packing (see note (2)).



10.1.5 Umbilicals

In order to control the Subsea Production System a dedicated electro-hydraulic umbilical system will be installed. The umbilical will supply to Subsea Production System equipment the hydraulic power, chemicals, electrical power and control signals, see ref. [12].

The following scenario will be considered

Umbilical from JKK Cluster 1:

This scenario considers using the existing JKK Main UMB 1 to control Field. An assessment was performed by subsea control vendor (refer to feasibility study for details). **Errore. L'origine riferimento non è stata trovata.**For such scenario the network of UMBILICAL consist in:

- UMB1: flying leads connect UMB1 UTA A to JKK Cluster 1 SDU and to HIPPS, all located near JKK Cluster 1. UMB1 UTA B connects to 3b and to Project UMB2 UTA A via flying leads.
- UMB2: UMB2 is connected in daisy-chain to UMB1 via flying leads. UMB2 UTA B connects to 4 Xtree via flying leads.

Block Diagram for this scenario is in Ref [2]. For further details of the umbilical system refer to Ref [31].

In order to benefit from existing design and equipment, the spare umbilical of Merakes infield UM1C will be used for UMB2. The umbilical UMB1 shall be designed to support the control of the HIPPS module, 3b and 4. The base case is to avoid additional design variant, therefore to use same design as UMB2. The aim is to to minimize customized design and engineering activities for project; however, further optimisation may be evaluated for the UMB1 design, e.g. 1-off 1.5" MEG.

10.1.6 Control System Description

Each Xtree and HIPPS will be controlled by its dedicated SCM. Flying leads will distribute control to the SCMs from the UTAs to the host structures. The subsea control system shall be compatible with the existing subsea control system and be designed in accordance with company standard 18010.ENG.STA.STD; HIPPS shall be designed based on requirements stated inside 28746.ENG.STA.STD.

Communication type will be "Communications On Power" (COPS) and the hydraulic system will be closed loop with a return line from subsea to surface.

The subsea system will be controlled topside by the existing Jangkrik topside control system. Modifications to the existing topside facilities will be required and include software and hardware updates. Hardware updates may be carried out one channel at a time and therefore could potentially be executed without need to shutdown JKK cluster 1. However, software updates on the topside system may require production shutdown. For more details see [30][31].

10.1.7 Flowlines System

Flexible pipeline shall be considered for the development of the development project.

The below table includes all the design input to be considered for the flexible pipeline design and routing analysis. Preliminary indications on flexible jumpers are also included.

Standard	23020.ENG.SSE.STD
International Code	API 17B API 17J
Inside Diameter for flowline 1 and 2	12" – 304.8 mm
Inside Diameter for flowline 3	11.5" – 292 mm (*)
Inside Diameter for Flexible Jumper (**)	12" – 304.8 mm

Inside Diameter for Well Jumpers	8" ID
Inside Diameter for Interconnecting Flowline	8" ID
Design Temperature	70°C
Design Pressure for flexible flowline 1, 2	270 bar
Interconnecting flowline	205 bar
Design Pressure for Flexible flowline 3 (*)	520 bar
Design Pressure for flexible jumper (**)	205 bar
Water depth	1200 mt

(*)Spare 11.5" flexible line will be used from Merakes Project.

(**) Flexible jumper will be needed to connect the existing JKK manifold 1 with the new FLET.

Use of flexible solution has been evaluated during the concept selection phase in terms of mechanical response to the required service conditions and to the foreseen water depth.

Flexible pipeline has been also compared against the rigid solution in terms of cost, schedule and installability.

Flexible jumpers are assumed to be needed also between 2 and 4 wells and relevant structure:

Flexible Well Jumper Design Pressure	520 bar
Flexible Well Jumper Design Temperature	70 °C
Flexible Well Jumper Length / nr.	~90 mt / 2

11 HEALTH, SAFETY, ENVIRONMENT

The project is developed in compliance with Indonesia and Upstream HSE policies, referring to ISO 14001 requirements for Environmental Management Systems, ISO 45001 and OHSAS 18001 for Occupational Health and Safety Management Systems.

Indonesia HSE Policy are considered as the reference to define HSE Project Requirements as well as the compliance to the Upstream Standards and 10 HSE policies.

HSE design criteria to be applied to the present Concept Definition Phase are reported in the preliminary Health, Safety and Environmental (HSE) Philosophy. The document aims to ensure an inherently safe design, in order to:

- Minimize the potential of hazardous occurrences;
- Minimize the risk and consequences of an accidental event;
- Ensure a safe working environment for personnel;
- Ensure adequate means of escape in case of emergency;
- Provide sufficient safety devices and redundancy to detect, isolate and minimize uncontrolled releases of flammable and toxic fluids;
- Provide appropriate fire protection systems to rapidly bring under control and extinguish any reasonably foreseeable fire which could develop during normal operations;
- Minimize the potential pollution of the environment.

The project development shall be supported by an HSE design based on a formal risk-based assessment process (e.g. HAZID, HAZOP, ESHIA, other safety studies). The aim of the formal safety assessment process is to ensure that all potential hazards have been identified, associated risks assessed, and measures taken to eliminate, reduce, control or mitigate the consequences of those hazards.

11.1 Safety Criteria

The objectives of the HSE Criteria are to:

- minimise the risk and consequences of an accidental event;
- minimise the potential for hazardous occurrences;
- maximise the benefits of protection measures;
- provide sufficient safety devices and redundancy to isolate and minimise uncontrolled releases;
- provide appropriate fire protection systems to control any reasonably foreseeable fire which could develop during normal operations;
- ensure adequate means of escape and rescue are provided from all areas;
- minimise the potential for pollution of the environment from accidental spills, venting or flaring of hazardous materials;
- ensure that all operational hazards and risks are minimised during construction including that in existing plant.

The goal of a safe facility design is to eliminate the high (intolerable) risks and to reduce the medium (tolerable) risks to a level that can be demonstrated to be ALARP. This is carried out by reducing the probability of occurrence of events and minimizing their consequences.

The main principles for safe facilities design and operation are:

- support for design decisions making based on sound safety reasoning;
- containment of hydrocarbons and prevention of hydrocarbon ignition;
- minimization of the chances of ignition;
- prevention of fire escalation and gas monitoring;
- provision of personnel protection and escape.

11.2 Health Considerations

The Project will meet the health and regulatory compliance requirements and assure the appropriate protection of worker health (employees and Contractors) from adverse health effects that may result from the design, construction, commissioning and operations activities.

As per above, the health related risk based approach will include the following objectives:

- Identify and evaluate health hazards/risks (e.g., occupational health risks / exposures, vector-borne disease, infectious disease, accommodations, food and water, medical support, etc.).
- Mitigate health hazards/risks.
- Communicate health hazard/risk information.
- Define staff medical fitness for duty evaluation programs.
- Assess health of potentially exposed workers.
- Verify satisfactory health management through health inspections and surveillance including industrial hygiene management.

In addition to the Project health specifications which will be further developed during the next Project phase, the following considerations, and not limited to, shall also be further defined and incorporated into facility design:

1. Facility Noise Sound Level Design Criteria.
2. Medevac arrangements.
3. Emergency Shower and Eyewash Facilities.
4. Design of Hazardous Materials Storage and Handling Facility.

11.3 SIMOPS

Simultaneous Operations (SIMOPS) refers to the multiple activities such as continuous production of hydrocarbons (oil or gas), executed concurrently, with drilling, maintenance, construction, commissioning or well operations in any existing oil and gas facility. The primary benefits of carrying out simultaneous operations whilst maintaining production are the economic incentives within controllable risk, thus minimising the deferment of hydrocarbon production.

The interaction between the multiple activities tends to result in an increased operational complexity and higher level of risk. This is because during each SIMOPS, more than one activity being conducted concurrently may result in the introduction of additional risk and increased probability of failure to control the hazard associated with these risks. For example, presence of additional ignition sources from hot work activities such as cutting, welding, etc., would increase the probability of ignition should there be a hydrocarbon leak on the process facility nearby.

11.4 RISK IDENTIFICATION

During current Project Phase the following studies will be carried on:

- HAZID Analysis:
HAZID is a structured review technique for the early identification of all significant hazards associated with the particular activity under consideration. HAZID is carried out by a systematic analysis of all the potential external threats with the potential to generate health, safety, environmental, asset and reputational risks.
- HAZOP Analysis:
HAZOP studies shall be used to analyze the design of operating facilities, new facilities or modifications to process and utility systems as a way of rigorously and systematically checking the design for safety, operability and conformity with codes of practice.

All these sessions have the aim to identify as soon as possible all risks associated to the production phase that can have impact principally on Safety, Environmental and Asset. Risk matrix that will be used for risk ranking (when required) as reported below:

Consequence					Increasing Annual Frequency					
Severity	People	Environ.	Assets	Reputation	0	A	B	C	D	E
					Practically non-credible occurrence	Rare occurrence	Unlikely occurrence	Credible occurrence	Probable occurrence	Likely/Frequent occurrence
					Could happen in E&P industry	Reported for E&P industry	Has occurred at least once in Company	Has occurred several times in Company	Happens several times/y in Company	Happens several times/y in one location
1	Slight health effect /	Slight effect	Slight damage	Slight impact	Continuous Improvement					
2	Minor health effect / injury	Minor effect	Minor damage	Minor impact						
3	Major health effect /	Local effect	Local damage	Local impact	Risk Reduction Measures					
4	PTD or 1 fatality	Major effect	Major damage	National impact						
5	Multiple fatalities	Extensive effect	Extensive damage	International impact						
					High Risk					

Table 21: Basic risk matrix (full qualitative approach)

All recommendations arisen during sessions will generate an action that will be in charge to the dedicated department.

All actions shall be correctly managed before the end of current Project phase, with evidence of their implementation.

11.5 Environmental, Social and Health Impact Assessment

During FEED Project phase a Environmental, Social and Health Impact Assessment SoW has been produced.

The outcomes of the study will be shared with Contractor for design purposes.

12 GHG EMISSION AND MITIGATION OF CLIMATE CHANGE EFFECTS:

The Company has a strong commitment to reduce GHG emissions in business initiatives: the impact shall be minimized deploying proper technologies and taking into account an optimization on the overall project production life. This shall be achieved through appropriate measures, depending on the specific project characteristics.

In particular:

- No routine flaring is allowed at any stage of the project.
- Non-routine flaring shall be minimized.
- Metering systems shall be installed for all gas streams.
- Continuous CO₂ venting from fluids nor Methane venting contained is allowed at any time of production.
- Stationary combustion emissions shall be minimized always preferring low energy intensity processes and deploying high efficiency fuel gas-based power generation systems or evaluating connection to local power network where feasible.

12.1 Water Management

The minimum general requirements to be adhered to are as follows:

- Reduction of the usage of water shall represent one of the main design criteria. Water re-use shall be preferable to recycle. Water recycle shall be preferable to water discharge.
- Installation of flow meters for each water stream (input and output) shall be assured.

Any discharge of water brought into contact with hydrocarbons, chemicals, and any potential source of contamination shall be routed to treatment system before final disposal.

13 REGULARITY AND OPERATION

The Regularity and operation principles of Development Project aim at ensuring uninterrupted exploitation operations, maximizing the ergonomics of installation and minimizing operation life-cycle cost, assuring the asset integrity, reducing the risk of accident occurrence, minimizing worker exposure to risks and protecting the environment.

The assurance will be achieved by having in place appropriate management control and engineering practices that meet the requirements of the Company, international standards and legal obligations and any other applicable national regulation (see also ref. [3]).

Asset Life Cycle processes will be formalized in Development Management System (DMS) and Operation Management System (OMS), providing directions and requirements for all those activities of Development and Production processes involving Indonesia.

The FPU will be permanently manned while a non continuous presence of workers is foreseen for the onshore facilities (i.e. unattended operations).

The staff onboard the FPU will operate in turning shifts and will be accommodated in the LQ module that will include living room, recreation room, first aid facilities and a Helideck.

In order to optimize the levels of the manning commensurate with the control technology adopted, the following criteria will be implemented:

- Utilize support infrastructure to manage staffing levels synergies;
- Ensure high levels of staff competence in all teams;

- Adopt empowerment approach to work;
- Adopt suitable staff competence assurance and development methods;
- Implement a contracting plan aimed to supplement staffing needs with external technical sources;
- Take into consideration the local content requirements.

14 SIMOPS AND CONOPS REQUIREMENTS

In this chapter all the specific requirements for SIMOPS and CONOPS coming from the development/project within or nearby existing or operating facilities or nearby other operations.

SIMOPS

It is preliminary considered that during the installation activities of EPCI facilities there is a risk that the following activities may be accomplished simultaneously:

- Drilling and completion activities
- Production from facilities already handed over to Company.

CONOPS

It is preliminary assumed that any FPU activity under EPCI scope will be performed simultaneously with FPU production.

Further analysis will be made to deeper comprehend the criticality and the advantages of this solution and eventually propose alternative options.

15 ATTACHMENTS

Annex 1 – Limits and Quality Standards