PROJECT ALPINE

Basis of Design

1 EXECUTIVE SUMMARY

This document establishes the preliminary **Basis of Design** for the offshore production facilities and associated subsea systems forming part of **PROJECT ALPINE**, located within the **Horizon South** offshore exploration block in the **Pelagia Basin**. The scope addresses both topside and subsea infrastructure intended to support the commercial development of the field, including provisions for integration with the **Central Nexus Facility**.

The content herein consolidates the current understanding of the **Aurora-1** and **Epsilon-4** wells, encompassing reservoir performance characteristics, produced fluid properties, and indicative well productivity profiles. It also incorporates the latest available geomorphological surveys and metocean design parameters relevant to installation and operational considerations in the northeastern seaboard waters of **Valmora Island**.

An initial conceptual arrangement of the field development system is provided, outlining potential subsea architecture, tie-back routes, and processing options. This arrangement is intended as a baseline reference for **PRIME ENERGY** and its project partners—**Stratos Energy Ltd.** (Operator, 40% interest), **Novara Petrochem** (30%), and **Helix GeoVentures** (30%)—to support further engineering definition by prequalified tenderers.

The document will be progressively refined as **PROJECT ALPINE** advances through its development phases. Updates are anticipated at key decision gates, including prior to Front-End Engineering Design (FEED) commencement, and following the incorporation of new data from drilling campaigns undertaken by **TerraNova Drilling Co.** and other service providers.

2 INTRODUCTION

The hydrocarbon resource under consideration is situated within the **Horizon South** offshore exploration block, part of the greater **Pelagia Basin** along the northeastern maritime boundary of **Valmora Island**. **Horizon South** is currently under the operatorship of **Stratos Energy Ltd.** (40% participating interest), in partnership with **Novara Petrochem** (30%) and **Helix GeoVentures** (30%). The concession was secured under a revised production-sharing arrangement tailored to distribute investment risk among stakeholders, with contractual rights awarded in August 2019 and commercial terms becoming effective in January 2020.

The first exploratory campaign in the block was executed through the drilling of the **Aurora-1** well, undertaken by **TerraNova Drilling Co.** The well was spudded on 21 May 2002 in water depths of approximately 2,436 feet, reaching a total measured depth of 13,441 feet (true vertical depth of 13,100 feet). Drilling operations concluded on 7 June 2002.

Historical exploration in the vicinity had already indicated hydrocarbon potential, most notably through the **Epsilon-4** well drilled in 2001 by former license holder **BlueArc Resources**. Both **Aurora-1** and **Epsilon-4** are positioned along the southwestern flank of the principal structural high, separated by a subsurface saddle feature that influences reservoir connectivity and development planning.

2.1 Field Development Strategy

The preferred development concept foresees a subsea tie-back to existing offshore facilities, leveraging underutilized processing and export infrastructure approaching late-life production. This approach provides a cost-efficient route to commercialization while mitigating the environmental footprint of new installations. The planned connection point is strategically located in proximity to the **Central Nexus Facility**, thereby reducing the extent of modifications required and facilitating smooth integration into the established production network.

3 LOCAL ACTS, LAWS, RULES, AND REGULATIONS

3.1 Environmental Emission Limits

Refer to [7].
Any project activities within **PROJECT ALPINE** that could potentially affect the surrounding environment—such as pre-commissioning or hydrotesting of subsea flowlines—shall undergo a detailed assessment in coordination with the project's HSE (Health, Safety & Environment) team. This ensures that any relevant environmental thresholds, as established under **Serandia's** legislative framework, are identified and adhered to prior to execution.

3.2 Regulatory Compliance

Refer to [3] *[Reference origin not found]*.

3.3 Order of Precedence

All applicable acts, laws, rules, and regulations for **PROJECT ALPINE** shall align with those enforced for offshore operations within **Serandia**. In cases where multiple regulatory frameworks overlap, the most stringent requirement will take precedence.

The hierarchy of application shall be as follows (with 1 being the highest):

1. **Serandian** national laws, regulations, and any international conventions ratified by **Serandia** pertaining to offshore exploration and production.
2. Applicable classification society requirements, vessel flag regulations, marine international standards, and certification body rules for the specific equipment category.
3. Approved **PROJECT ALPINE** documentation (Appendix D).
4. **PRIME ENERGY** corporate engineering standards (latest revision to be applied to new equipment per [3] *[Reference origin not found]*).
5. Internationally recognized codes and standards relevant to the scope of work.

4 PROJECT DESCRIPTION

4.1 Development Scenario

The **Aurora-1** gas discovery well was drilled in 2,436 ft water depth by **TerraNova Drilling Co.** under contract with a prior project operator, reaching total depth on 7 June 2002 at a true vertical depth subsea (TVDSS) of 13,100 ft. Following a series of unsuccessful development proposals for **Aurora-1** and nearby discoveries, the acreage was relinquished.

In 2019, the **Serandian Ministry of Energy** reoffered the block during its offshore licensing round, where **Stratos Energy Ltd.** (Operator, 40%), **Novara Petrochem** (30%), and **Helix GeoVentures** (30%) secured exploration and exploitation rights under the revised production-sharing framework.

The proposed development of **Aurora-1** provides a synergistic opportunity to extend the operational lifespan of the **Horizon South** asset. Declining output from nearby producing fields offers capacity in the existing infrastructure, enabling the new project to deliver incremental reserves and economic benefits to both the Government of **Serandia** and the project stakeholders along the gas processing and export value chain—from the subsea wellhead to the onshore terminals.

The selected concept is a subsea tie-back to the **Central Nexus Facility**, leveraging ullage in late-life infrastructure and proximity to existing manifold clusters. The base plan comprises two new production wells tied into **Horizon South Trunkline 1** via a new subsea production flowline. Production from **Cluster 1** will be redirected for processing through **Cluster 3**, optimizing field performance while minimizing additional topside modifications.

5 GENERAL LOCATION DATA

5.1 Climatology and Metocean Data

Environmental parameters for the **Pelagia Basin**, including seawater temperature profiles, current regimes, and wave statistics, are provided in Ref. [25]. These datasets form the baseline for offshore design criteria in compliance with **Serandian** regulatory requirements.

5.1.1 Water Depths

The **Horizon South** development area spans water depths between approximately 300 m and 1,200 m below mean sea level.

5.1.2 Offshore Facility Coordinates

The primary floating production unit (FPU) within the **Central Nexus Facility** is located at the following reference coordinates:

Item	X [m]	Y [m]	Latitude	Longitude
FPU Centre	572421	9860512	1° 15' 42.868" S	117° 39' 03.499" E

Table 1 – Central Nexus Facility FPU Coordinates

5.1.3 Onshore Processing Location

The coordinates for the onshore receiving and processing facilities (ORF) associated with **Horizon South** are as follows:

- Latitude: 9,899,144 N to 9,899,370 N
- Longitude: 519,077 E to 519,329 E

5.1.4 Environmental Reference Data

For detailed metocean parameters—including design return periods—refer to Ref. [25]:

Doc No.	Document Title	Revision
RP_A11111v1 – Main (Feb 2012)	SPS Basis of Design	—

Table 2 – Metocean Reference Data

Design return periods applicable to offshore oil and gas facilities are governed by national regulations or industry codes. For guidance specific to **PRIME ENERGY** projects, refer to Company Standard 28842.ENG.OFF.STD *"Meteo-Oceanographic Design Basis"*.

5.2 Geophysical and Geotechnical Data

5.2.1 Geotechnical

No dedicated geotechnical investigation has yet been performed for the **Aurora-1** development area. A comprehensive site survey is planned in upcoming project phases to characterize seabed soils at proposed subsea structure, flowline, and umbilical installation locations.

5.2.2 Geophysical

Geophysical survey data are not currently available for the **Aurora-1** project footprint. A future campaign will acquire high-resolution bathymetry and shallow sub-seabed profiles to support engineering and hazard assessments. This will include seabed morphology mapping, shallow stratigraphy, and identification of potential hazards to subsea infrastructure.

5.2.3 Bathymetry Data

Current bathymetric information is limited to low-resolution (12.5 m × 12.5 m grid) data obtained from reprocessed 3D seismic datasets. The development area is characterized by complex seabed topography, including multiple submarine canyons (both primary and tributary), distinct fault lines, steep escarpments, irregular slopes, and isolated mounded features. Water depths range from approximately 300 m to 1,500 m.

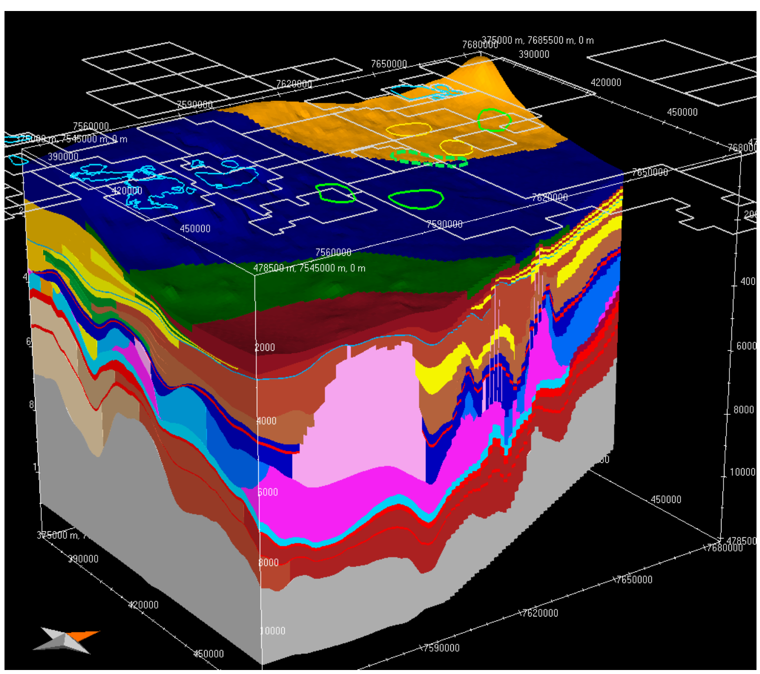

Figure 3 – Regional morphology of the Pelagia Basin development zone.

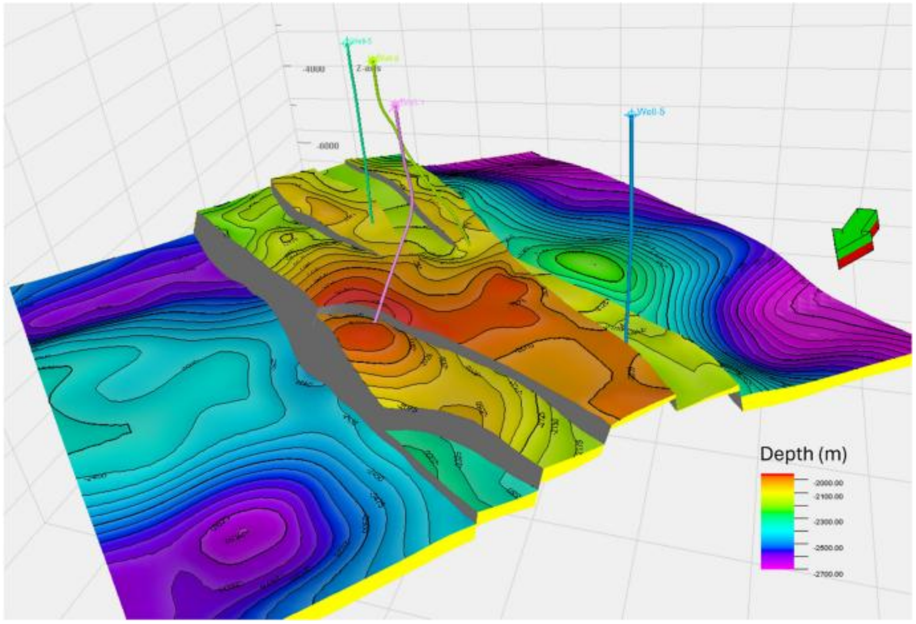

Figure 4 – Detailed bathymorphic interpretation of the Aurora-1 sector from reprocessed 3D seismic volume.

5.2.4 Geohazard Assessment

No dedicated geohazard studies have been carried out to date for the **Aurora-1** development area. This assessment will form part of the upcoming geophysical and geotechnical survey scope.

5.2.5 Earthquake Data

Seismic design criteria for subsea structures and associated foundations shall be in accordance with ISO 19901-2.

6 RESERVOIR MANAGEMENT BASIS

6.1 Main Reservoir Data

The primary reservoir identified within the **Aurora-1** structure of **PROJECT ALPINE** is classified as **T-090** (equivalent to legacy interval 3130 from the former operator's nomenclature). This unit was encountered at depths between –2,400 m and –2,600 m true vertical depth subsea (TVDSS).

Secondary accumulations include **T-088 / T-086** (equivalent to legacy 3140 and 3150) and **T-084 Segment-1** (equivalent to legacy 3170). The field is a **Pliocene-age turbidite system**, deposited approximately 3.5 million years ago as toe-of-slope fans prograding across an anticlinal structure associated with the broader **Pelagia Basin Hub anticline**. Hydrocarbon trapping is predominantly stratigraphic, driven by the up-dip pinch-out of turbiditic sequences into a slope valley.

The **T-090** interval represents the principal gas-bearing horizon, accounting for roughly 74% of the estimated gas-in-place. Seismic amplitude and envelope attribute analyses illustrate a channel-fed fan geometry sourced from the northwest. Depositional lobes display compensational stacking with evidence of lateral amalgamation, which complicates architectural interpretation. No gas–water contact (GWC) was directly observed in well control; however, amplitude cut-off suggests a contact near –2,560 m subsea level.

The **T-088 / T-086** reservoirs were encountered approximately 30–40 m below the primary target, comprising two distinct sand bodies identified in the **Aurora-1** and **Epsilon-4** wells. MDT pressure testing confirmed a consistent gas–water gradient across both wells, with GWC observed at –2,556 m in **Aurora-1**, while **Epsilon-4** proved water-bearing. These intervals are interpreted as more channelized deposits, with two primary fairways trending NW–S and NW–SE. Localized bottom-current reworking and crevasse splays are inferred in the southeastern portion of the block.

The basal **T-084** reservoir constitutes the lowest sand package of the Pliocene slope-valley system. Seismic RMS amplitude extractions indicate possible channelized features near **Aurora-1** and depositional lobe development to the south of **Epsilon-4**. Gas saturation was confirmed in **Aurora-1**, with GWC measured at –2,626 m TVDSS by MDT, while **Epsilon-4** did not penetrate this horizon. MDT data also indicate **T-084** is moderately overpressured relative to overlying sands.

Petrophysical evaluation from the 2020 **Integrated Reservoir Study** confirmed net pay and reservoir quality in both **Aurora-1** and **Epsilon-4** wells across T-090, T-088 / T-086, and T-084 intervals. The results are summarized below.

Well	Reservoir	Gross Interval (m TVD)	Net Reservoir (m TVD)	NTG	Avg. Porosity (PHIE)	Avg. Water Saturation (Sw)	Avg. Permeability (mD)
Aurora-1	T-090	23	21	0.90	0.25	0.42	76
Epsilon-4		54	43	0.80	0.26	0.45	129
Aurora-1	T-088/086	72	34	0.46	0.24	0.48	109
Epsilon-4		55	24	0.43	0.25	—	177
Aurora-1	T-084	21	20	0.94	0.30	0.16	288
Epsilon-4		Not penetrated	—	—	—	—	—

Table 6 – Average Reservoir Properties from Aurora-1 and Epsilon-4 Wells

A 3D static model has been constructed, integrating seismic, well, and analogue data to better capture reservoir architecture and original gas-in-place estimates.

Case	Avg NTG [%]	Avg Porosity [%]	Avg Water Saturation [%]
Reference Case	67	27	39
T-090	75	27	41
T-088/086	43	25	44
T-084	83	33	20

Table 7 – Average Reservoir Properties from Volumetric Modeling

No PVT experiments have yet been conducted on recovered cores from **PROJECT ALPINE**. Fluid characterization was therefore derived from MDT sampling at T-090, with analysis performed at 2,487 m depth, 3,903 psia reservoir pressure, and 151 °F reservoir temperature. Results indicate a methane-rich gas (C1 content 98.3%), with a gas gravity of 0.58 and condensate–gas ratio (CGR) of 5.8 stb/MMscf. The dataset was calibrated through an equation-of-state model (PVTi), and the **T-090 fluid properties** are currently applied to secondary reservoirs for preliminary design.

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

Table 8 – Reservoir Fluid Conditions

The **Aurora-2** well, drilled in May 2021, further confirmed reservoir quality in the T-090 interval. Full core and PVT analysis remain pending at the time of this Basis of Design.

6.2 Reservoir Fluid Composition

The molar composition of the produced fluid from **Aurora-1 (T-090)** is summarized below:

Component	%mol	MW	Specific Gravity	Critical Temp. (°C)	Critical Pressure (bara)	Acentric Factor	Boiling Temp. (°C)	Critical Vol. (cm^3/mol)
N_2	0.040	28.01	—	–147.0	33.9	0.0400	–195.8	89.8
CO_2	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
n-C4	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

n-C5	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 (Aurora-1 MDT Sample, T-090)

7.0 DRILLING & COMPLETIONS

7.1 Overview

The field development concept foresees the drilling of two production wells, provisionally designated as **Well A-3** and **Well A-4**.

7.2 Target Coordinates

The following tables summarize the preliminary wellhead coordinates as defined under current geodetic references (UTM / WGS 1984).

Well A-3

Parameter	Value
Water depth (m)	811
RKB elevation (m)	25
Seabed from RKB (m)	836

Wellhead Coordinates – Offshore Development Area A-3 (Case B)

- Northing: 9,852,056 m
- Easting: 583,427 m
- Latitude: 1° 20' 18.163" S
- Longitude: 117° 44' 59.719" E
- Datum: WGS 1984, UTM Zone 50S

Well A-4

Parameter	Value

Water depth (m)	1103
RKB elevation (m)	29
Seabed from RKB (m)	1128

Wellhead Coordinates – Offshore Development Area A-4

- Northing: 9,851,286 m
- Easting: 585,820 m
- Latitude: 1° 20' 43.223" S
- Longitude: 117° 46' 17.159" E
- Datum: WGS 1984, UTM Zone 50S

7.3 Preliminary Casing Design

As no dedicated pore pressure study has yet been finalized, the casing program is based on analogues from previous deepwater projects in the same basin. The proposed casing/liner string dimensions and metallurgy are aligned with industry practice and prior successful campaigns.

Proposed Casing Setting Depths – Well A-3

- 36” Conductor – depth 906 m MD
- 20” Surface Casing – depth 1486 m MD
- 13-5/8” Intermediate – depth 2100 m MD
- 10-3/4” Liner – TOL 2051 m MD, length 1127 m, overlap 120 m

Proposed Casing Setting Depths – Well A-4

- 36” Conductor – depth 1198 m MD
- 20” Surface Casing – depth 1728 m MD
- 13-5/8” Intermediate – depth 2250 m MD
- 10-3/4” Liner – TOL 2152 m MD, length 1150 m, overlap 120 m
- 7” Contingency Liner (if required) – TOL 3182 m MD, length 1023 m, overlap 120 m

Corrosion Considerations

Formation fluid sampling indicates the presence of significant CO_2 partial pressure, requiring corrosion-resistant alloys for flow-wetted tubulars. The recommended material is

13Cr (or Super 13Cr) stainless steel for production liner and tubing. For casing above the packer, carbon or low-alloy steel qualified for sour service in accordance with API 5CT is considered suitable.

7.4 Completion Schematics

The well-completed strategy has been developed in line with international standards and internal well design procedures, incorporating the following principles:

- Compliance with HSE regulations
- Delivery of forecasted production rates
- Capability for gas and water injection as needed
- Operational safety and equipment reliability
- Well longevity over full life cycle
- Optimization of rig time and cost efficiency
- Use of standardized, field-proven technology
- Resilience against worst-case operating conditions

Completion Concepts Under Evaluation

1. **Well A-3**: Dual-zone completion within 10-3/4" liner, using Controlled Hydraulic Flow Profile (CHFP) and smart upper completion.
2. **Well A-4**: Single-zone CHFP inside 10-3/4" liner, with provision for future dual-zone configuration if required. Smart completion capability will be retained for operational flexibility.

The strategy emphasizes larger completion sizes to maximize gas deliverability compared with conventional 9-5/8" liner systems. Alternative designs may be considered in later project phases.

7.5 Preliminary Metallurgy & Elastomer Selection

A dedicated completion material and elastomer compatibility study has not yet been undertaken. Based on analogues from prior basin developments, 13Cr (or enhanced grades thereof) is anticipated to be the baseline metallurgy for cost and corrosion considerations. This selection will be revisited during subsequent project phases once reservoir fluid characterization is further refined.

8.0 FLUID DATA AND PRODUCTION CHEMISTRY

8.1 Reservoir Fluid Properties

Given the combination of high pressure and relatively low temperature expected during both steady-state and transient operations, the reservoir fluids are predicted to be susceptible to hydrate formation.

Hydrate risks will be mitigated under all scenarios through continuous injection of lean MEG solution (80% wt). A supplementary injection of methanol will be applied during start-up and restart operations to counteract low-temperature excursions and hydrate risks.

No issues are anticipated with asphaltenes, foaming, or emulsion stability. However, scale formation potential is assumed to be present, consistent with analogue reservoirs in the basin.

8.2 Reservoir Fluid Composition

Reservoir fluid composition is referenced in Section 7.2.

8.3 Scale Potential

Scaling tendencies are considered comparable to neighbouring developments within the basin. Preventive strategies will be aligned with established operating practices for carbonate-rich produced water systems.

8.4 Wax Formation and Rheology

No wax deposition, foaming, or emulsion challenges are expected under reservoir or production conditions (see Section 9.1).

8.5 Hydrate Equilibrium Curves

Hydrate equilibrium curves were generated for reservoir fluid composition (Section 7.2), saturated at reservoir conditions of 30 bar and 74°C.

Figure 5: Hydrate formation curves (to be inserted).

8.6 Hydrogen Sulphide

The reservoir fluid is expected to be free of H_2S.

8.7 Asphaltenes

No asphaltenes are expected in the produced hydrocarbons.

8.8 Material Selection

8.8.1 CO_2 Corrosion

Produced fluids exhibit CO_2 partial pressure sufficient to cause sweet corrosion in the absence of H_2S. Dissolution of CO_2 into condensed water is expected, with concentrations proportional to partial pressure and temperature.

The material and corrosion-control philosophy emphasizes maintaining integrity across the design life while minimizing cost and fabrication delays. Mitigation methods include:

- Corrosion-resistant alloys and/or corrosion allowance
- Protective coatings
- Chemical inhibition programs
- Cathodic protection systems
- Continuous monitoring and inspection

Design corrosion allowances:

- Process equipment and piping: 3–6 mm
- Pipelines: up to 8–10 mm, depending on service

Uninhibited corrosion rate: estimated 0.9 mm/yr → ~8.8 mm wall loss over 20 years
With inhibition: reduced to 0.1 mm/yr (based on analogous fluid classification studies)

Formation Water Case

- Max corrosion rate: 2.0 mm/yr
- Inhibited rate: 0.2 mm/yr
- Corrosion allowance (15 years, 95% CI inhibitor availability): 4.35 mm

Condensed Water Case

- Max corrosion rate: 2.8 mm/yr
- Inhibited rate: 0.2 mm/yr
- Corrosion allowance (15 years, 95% CI inhibitor availability): 4.95 mm

Flowline material basis: Carbon steel + 5 mm corrosion allowance, assuming >95% inhibitor availability.

8.9 Flow Assurance

Flow assurance considerations are detailed in Section 9.1.

8.10 Flowing and Shut-In Conditions

8.10.1 Flowing Wellhead Pressure

The forecasted flowing wellhead pressures (FWHP) for the development wells are presented in Table 12.

Date	Project-4 (barg)	Project-3 (barg)
Sep-26	206	196
May-27	152	134
Jun-28	125	110
Dec-29	97	85
Jun-30	90	80
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, Flowing Wellhead Pressure (FWHP)

8.10.2 Flowing Wellhead Temperature

Forecasted flowing wellhead temperatures upstream and downstream of the pressure control valves are summarized in Tables 13 and 14.

8.10.3 Topside Arrival Conditions

For the base case, wells are produced in hybrid HP/LP mode, with arrival fluid temperatures expected between -2°C and +10°C depending on flowrate.

8.10.3.1 Operating Cases

Base Case: two new development wells are tied back via a 12” subsea production line into the existing trunkline system, routed through an intermediate cluster before reaching the central production hub.

8.10.3.2 Inlet Flowrate at Host Facility

Representative production cases for host facility inlet conditions are summarized in Table 15. These cases are used to confirm processing and slug catcher capacity.

8.10.3.3 Target LP Max Flowrate

- 616 MMSCFD max flow in LP mode (per production profile)

- With minor modifications, 600 MMSCFD is achievable
- With debottlenecking, 720 MMSCFD can be managed in LP mode (up to ~8,400 m^3/h seawater consumption)

8.11 Product Specifications

8.11.1 Produced Hydrocarbons

Produced gas and condensate will be processed at the host facility. Applicable sales specifications are:

Property	Specification
HC Dew Point	≤ 12°C at any pressure between 52 barg and max export pressure
Water Dew Point	≤ 9°C at max export pressure
Water content	≤ 9 lb/MMSCF

(Table 17: Produced Gas/Condensate Specifications)

8.11.2 Produced Water

Produced water will be treated onboard the host facility. Key discharge specifications:

- Max HC content: 15 ppmv (30-day avg), 42 ppmv (daily peak)
- Max MEG content: 3,500 ppmv
- Max discharge temperature: 40°C

Discharge streams will be continuously monitored per applicable national and environmental regulations.

8.11.3 H_2S Content

Reservoir fluids are expected to be free of H_2S.

8.11.4 CO_2 Content

Reservoir CO_2 content is ~0.92 mol%.

8.12 Field Flowrates for Design Basis

Table 19 summarizes the design case flowrates used for facility capacity verification.

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

(Table 19 – Development Design Cases)

9.0 FACILITIES

9.1 Subsea, Umbilical and Flowlines

The following section provides an overview of the subsea architecture for **PROJECT ALPINE**, covering subsea production hardware, umbilicals, subsea control systems, and flexible flowline arrangements.

9.1.1 Floating Production Unit (FPU)

For the overall process description of the Floating Production Unit, refer to [22].

9.1.2 Design Life

The subsea production and control system shall be designed for a service life of **20 years**.

9.1.3 Maximum Water Depth

All subsea equipment shall be rated for an installation water depth of **1,200 m**.

9.1.4 Main Subsea Equipment

A preliminary list of key subsea components and associated design parameters is provided below.

Table 20 – Preliminary List of Main Subsea Equipment

Item	Quantity	Design Pressure	Design Temperature
Production Xmas Tree	2	10,000 psi	Upstream choke: -18 / +121 °C Downstream: -48 / +121 °C
HIPPS System	1	(i) 270 bar header from HBV1 to inboard connector; header from TIV1 to inboard connector, incl. hot stab lines (ii) 421 bar for remaining header sections, valves and chem. injection lines	-20 / +70 °C
ALPINE Manifold Structure	1	270 bar for header; 650 bar for branch up to branch valve (valve included)	-20 / +70 °C
Subsea Hub Structure	1	520 bar across structure except header connectors (270 bar)	-29 / +70 °C

Umbilical Termination Assembly (UTA)	4 (2 per umbilical system)	—	—
Flowline End Termination (FLET)	1	TBD	TBD

Notes:

1. Xmas Tree conditions in line with ALPINE field specification.
2. MEG pump design pressure: 340 barg (PSV set point). Including hydrostatic head at 1,200 m = ~470 barg. See [32] for pressure definition under MEG packing conditions.
3. Subsea structure pressure defined by wellhead shut-in pressure (WHSP) × 1.1 = ~270 bar.
4. Design temperature includes operating maximum (55 °C) plus contingency margin (+15 °C).
5. A new FLET is anticipated for connecting ALPINE Cluster 1 with Cluster 3 through a new interconnecting line.

9.1.5 Umbilicals

A dedicated electro-hydraulic umbilical system will be deployed to provide hydraulic power, chemicals, electrical supply, and control signals to the subsea production equipment [12].

Umbilical Deployment Scenario (Cluster 1):

- The existing Cluster 1 Main Umbilical (UMB1) will be extended to support ALPINE subsea facilities.
- UMB1: Flying leads will connect UTA-A to the Cluster 1 SDU and to the HIPPS. UTA-B will connect to Well ALPINE-3B and to UMB2 UTA-A.
- UMB2: Configured in daisy-chain from UMB1. UTA-B will connect to Well ALPINE-4 via flying leads.

Block diagrams and detailed layouts are provided in [2] and [31].

Where practical, existing spare umbilicals from previous developments will be utilized to optimize design and reduce customization. For ALPINE UMB2, the spare infield UM1C from the LOCATION asset will be repurposed.

9.1.6 Control System

Each Xmas Tree and HIPPS unit will be operated by a dedicated Subsea Control Module (SCM). Flying leads will distribute power and control between UTAs and host subsea structures.

- The subsea control system shall be fully compatible with the existing ALPINE host system.
- Design shall comply with COMPANY standard **ENG.STA.STD.18010**, with HIPPS designed to standard **ENG.STA.STD.28746**.
- Communications will be via **COPS (Communications on Power)**.
- Hydraulic system design: closed-loop with return to the host facility.

Topside integration will be through the existing ALPINE control system. Hardware modifications (one channel at a time) may be performed without shutting down Cluster 1. Software updates, however, could require temporary production shutdown. See [30] and [31] for integration details.

9.1.7 Flowline System

Flexible pipelines have been selected for the ALPINE development. The table below summarizes preliminary design inputs for the flexible pipeline system and associated routing analysis.

Table 21 – Flexible Pipeline Design Inputs

Parameter	Value
Standard	23020.ENG.SSE.STD
International Codes	API 17B / API 17J
Flowline 1 & 2 ID	12” (304.8 mm)
Flowline 3 ID	11.5” (292 mm)*
Flexible Jumper ID**	12” (304.8 mm)
Well Jumper ID	8”
Interconnecting Flowline ID	8”
Design Temperature	70 °C
Design Pressure Flowline 1 & 2	270 bar
Design Pressure Flowline 3*	520 bar
Design Pressure Interconnecting Line	205 bar
Design Pressure Flexible Jumper**	205 bar
Water Depth	1,200 m

* Flowline 3 will reuse spare 11.5” flexible pipe from prior project inventory.

** Jumper required to connect the existing Cluster 1 manifold to the new FLET.

Flexible Well Jumpers:

- Design Pressure: 520 bar
- Design Temperature: 70 °C
- Length / Quantity: ~90 m / 2 units

Flexible solutions were confirmed during concept selection for suitability under mechanical, operational, and environmental conditions at 1,200 m water depth. Rigid alternatives were evaluated but flexible lines were selected due to advantages in cost, schedule, and install ability.

10.0 HEALTH, SAFETY, AND ENVIRONMENT (HSE)

The Project shall be developed in alignment with applicable **national regulations** and **corporate HSE requirements**, taking into account international standards such as:

- ISO 14001 (Environmental Management Systems)
- ISO 45001 (Occupational Health and Safety Management Systems)
- OHSAS 18001 (Occupational Health and Safety)

Corporate HSE policies and internal standards are used as the basis for defining the project HSE requirements. Preliminary HSE Philosophy has been prepared for the Concept Definition Phase, with the aim of ensuring an inherently safe design that:

- Minimises the likelihood of hazardous events.
- Reduces the potential consequences of accidental events.
- Ensures a safe working environment for all personnel.
- Provides adequate escape and rescue provisions in emergencies.
- Includes sufficient protective systems and redundancy to detect, isolate, and control accidental releases of flammable or toxic substances.
- Ensures effective fire detection, control, and extinguishing systems.
- Minimises potential environmental pollution.

HSE development will be supported by a **formal risk-based assessment process** (e.g. HAZID, HAZOP, ESHIA, and other safety studies). The goal is to identify hazards, evaluate risks, and implement effective mitigation and control measures.

10.1 Safety Criteria

The objectives of the Safety Criteria are to:

- Minimise the likelihood and consequences of accidental events.
- Reduce the potential for hazardous occurrences.
- Maximise the effectiveness of protective measures.
- Provide redundancy and safety devices to contain uncontrolled releases.
- Implement fire protection systems capable of controlling foreseeable fire scenarios.
- Ensure safe escape and rescue from all areas.
- Limit environmental pollution from accidental releases (spills, flaring, venting).
- Reduce construction-phase risks, including work in brownfield areas.

The overall design approach shall aim to eliminate intolerable risks and reduce tolerable risks to a level that is demonstrably **ALARP (As Low As Reasonably Practicable)**, through:

- Sound decision-making based on safety considerations.
- Containment of hydrocarbons and prevention of ignition.
- Reduction of ignition likelihood.
- Fire and gas detection and prevention of escalation.
- Ensuring personnel protection and evacuation provisions.

10.2 Health Considerations

The Project shall comply with all **health and regulatory requirements**, ensuring that the health of employees and contractors is protected during design, construction, commissioning, and operations.

The health risk-based approach will include:

- Identification and evaluation of occupational and community health risks (e.g., exposure, infectious disease, accommodations, water, food, vector-borne illness, medical support).
- Implementation of risk mitigation measures.
- Communication of health risk information.
- Medical fitness-for-duty programs.

- Health assessments for potentially exposed workers.
- Regular inspections and monitoring, including industrial hygiene programs.

Additional health-related design considerations include:

1. Facility noise level design criteria.
2. Medevac arrangements.
3. Emergency shower and eyewash stations.
4. Safe design for hazardous material storage and handling.

10.3 SIMOPS (Simultaneous Operations)

SIMOPS refers to conducting multiple activities concurrently (e.g., hydrocarbon production alongside drilling, construction, commissioning, or maintenance).

While SIMOPS allow production continuity and reduce downtime, they introduce additional operational complexity and risk, including:

- Higher probability of hazards due to concurrent activities.
- Increased ignition risks from hot work (e.g., welding, cutting) in areas near hydrocarbon systems.

Effective planning and control are required to manage SIMOPS risks while maintaining production.

10.4 Risk Identification

During the current Project Phase, the following structured studies will be performed:

- **HAZID (Hazard Identification):** Systematic early-stage review of potential external threats with the potential to create health, safety, environmental, asset, or reputational risks.
- **HAZOP (Hazard and Operability):** Detailed review of design and operations for new or modified process/utility systems, ensuring compliance with safety and operational standards.

The purpose of these assessments is to identify risks early and define mitigation actions.

Table 21: Example of Qualitative Risk Matrix

Consequence \ Likelihood	Rare	Unlikely	Possible	Likely	Almost Certain
Insignificant	Low	Low	Low	Medium	Medium
Minor	Low	Low	Medium	Medium	High
Moderate	Low	Medium	Medium	High	High
Major	Medium	Medium	High	High	Extreme
Catastrophic	Medium	High	High	Extreme	Extreme

Note: This qualitative risk ranking is subject to project-specific calibration.

All recommendations raised during the studies shall be tracked, assigned, and closed prior to completion of the Project Phase.

10.5 Environmental, Social and Health Impact Assessment (ESHIA)

An **ESHIA** has been developed during the FEED phase.
The results of the study will be provided to the Contractor for incorporation into detailed design.

11.0 Greenhouse Gas (GHG) Emissions and Climate Change Mitigation

The Project is committed to reducing greenhouse gas (GHG) emissions throughout all phases of development and operation. Emission reduction will be achieved through the adoption of appropriate technologies, optimization of energy consumption, and application of best industry practices across the asset lifecycle.

General Requirements

Requirement	Description
Flaring	Routine flaring is **not permitted** at any stage. Non-routine flaring shall be strictly minimized.
Venting	Continuous venting of CO_2 or methane is **not allowed** under normal operating conditions.
Gas Metering	Metering systems shall be installed for all gas streams.
Stationary Combustion	Emissions from stationary sources shall be minimized by prioritizing: (i) low energy intensity processes, (ii) high-efficiency fuel-gas-based power generation, or (iii) connection to local grid, where feasible.

11.1 Water Management

Water management is a core element of environmental protection. The following design and operational requirements apply:

Requirement	Description
Water Use Reduction	Water use shall be minimized; re-use is preferred over recycling; recycling is preferred over discharge.
Flow Measurement	Flow meters shall be installed on all intake and discharge streams.
Water Discharge	Any water contaminated with hydrocarbons, chemicals, or other pollutants must be routed to treatment facilities before final disposal.

12.0 Regularity and Operations

The Project's operational strategy aims to ensure continuous and reliable production while prioritizing safety, cost efficiency, and environmental protection. Key objectives include:

- Uninterrupted production operations.
- Safe and ergonomic facility design.
- Optimization of operational lifecycle costs.
- Protection of asset integrity.
- Reduction of accident risks and worker exposure.

Compliance will be ensured through management systems aligned with **international standards**, **industry best practices**, and **applicable national regulations**. Asset lifecycle processes will be governed under the **Development Management System (DMS)** and the **Operations Management System (OMS)**.

Operational Staffing

Facility	Manning Strategy
Floating Production Unit (FPU)	Permanently manned with rotating shifts. Accommodation facilities shall include living quarters, recreational areas, first aid, and helideck.
Onshore Facilities	Designed for unattended or periodically manned operations.

Staffing Principles

- Leverage support infrastructure to optimize staffing levels.
- Ensure high levels of competence across operational teams.
- Adopt empowerment approaches for efficient work execution.

- Implement continuous competence development and assurance.
- Utilize contracting plans to supplement workforce with specialized expertise.
- Align workforce planning with local content requirements.

13.0 SIMOPS and CONOPS Requirements

This section outlines requirements for **Simultaneous Operations (SIMOPS)** and **Concurrent Operations (CONOPS)** in relation to new project developments near existing or operating facilities.

SIMOPS

During installation and commissioning, the following activities may be conducted concurrently, introducing additional complexity and risk:

SIMOPS Activity	Potential Concurrent Operations
Drilling & Well Completion	Installation or commissioning of new facilities
Ongoing Production	Operation of nearby production units handed over earlier

Risk assessments shall be carried out to evaluate interactions between simultaneous activities and define mitigation measures.

CONOPS

For the Floating Production Unit (FPU), it is assumed that certain activities under the Engineering, Procurement, Construction, and Installation (EPCI) scope may occur concurrently with production operations. Further studies will determine:

- Criticality of simultaneous execution.
- Benefits and risks of maintaining concurrent operations.
- Alternative strategies if concurrent execution is deemed unsuitable.